Native Excel Detail ATTACHMENT E [PDF: ATTACHMENT A]
Avista Utilities
2023 Capital Additions (System-Basis) - Summary by Business Case

Support of the 2023 capital pro forma and provisional additions were provided with the Company's direct filed case, including a description of each Business Case located within the respective direct testimony of Company witnesses Mr. Thackston (Exh. JRT-1T), Mr. Magalsky (Exh. KEM-1T), Ms. Rosentrater (Exh. HLR-1T), Mr. Kensok (Exh. JMK-1T), Mr. Howell (Exh. DRH-1T) and Mr. Kinney (Exh. SJK-1T). Additionally, an exhibit was filed with each witness's testimony including each full Business Case as noted in Column (F).
Additional support is provided as follows:

- Attachment B - Detail actual transfer-to-plant by month amounts and in-service dates
- Attachment C - Capital Variance Explanation Forms and supporting justification by Business Case
- Attachment D - Business Cases not included in direct filing under threshold
- Attachment E - Native Capital Adjustment excel file supporting transfers-to-plant and Net Plant After ADFIT balances
- Attachment F - Listing of Infrastructure Investment and Jobs Act and the Inflation Reduction Act Grant Opportunities

		(A)	(B)	(C)	(D)	(E)	(F)		(G)
Witness	**Business Case**	**2023 As-Filed TTP (1) Gross Plant**	**2023 Actual TTP (1) Gross Plant**	**Variance $** over/(under) **Gross Plant**	**Variance %** over/(under)	**$500k & +/- 10% TTP Threshold**	**Direct Filed Exhibit Exh. #**	**Direct Filed Exhibit Pg#**	**Attach-ment C Pg#**
Kensok	Atlas	$ 2,948,867	$ 745,956	$ (2,202,911)	-75%	yes	Exh. JMK-2	133	3
Kensok	Basic Workplace Technology Delivery	$ 800,005	$ 2,029,989	$ 1,229,984	154%	yes	Exh. JMK-2	3	9
Thackston	Cabinet Gorge Dam Fishway	$ 235,000	$ 754,676	$ 519,676	221%	yes	Exh. JRT-4	30	26
Thackston	Cabinet Gorge HVAC Replacement	$ 1,500,000	$ -	$ (1,500,000)	-100%	yes	Exh. JRT-4	169	30
Thackston	Cabinet Gorge Station Service	$ 5,152,936	$ -	$ (5,152,936)	-100%	yes	Exh. JRT-4	178	31
Thackston	Cabinet Gorge Stop Log Replacement	$ 1,200,000	$ -	$ (1,200,000)	-100%	yes	Exh. JRT-4	184	39
Thackston	Cabinet Gorge Unwatering Pumps	$ 395,016	$ 913,476	$ 518,460	131%	yes	Exh. JRT-4	192	42
Thackston	Clark Fork Settlement Agreement	$ 5,622,720	$ 4,869,944	$ (752,776)	-13%	yes	Exh. JRT-4	51	47
Kensok	Control and Safety Network Infrastructure	$ 1,282,468	$ 528,524	$ (753,944)	-59%	yes	Exh. JMK-2	227	48
Magalsky	Customer Experience Platform Program	$ 6,300,000	$ 3,951,593	$ (2,348,407)	-37%	yes	Exh. KEM-2	10	56
Magalsky	Customer Facing Technology Program	$ 4,699,999	$ 3,777,726	$ (922,273)	-20%	yes	Exh. KEM-2	19	64
Magalsky	Customer Transactional Systems	$ 3,500,000	$ 2,589,501	$ (910,499)	-26%	yes	Exh. KEM-2	31	65
Kensok	Data Center Compute and Storage Systems	$ 2,063,801	$ 3,871,280	$ 1,807,479	88%	yes	Exh. JMK-2	12	66
Kensok	Digital Grid Network	$ 2,121,419	$ 3,485,617	$ 1,364,198	64%	yes	Exh. JMK-2	22	73
Rosentrater	Distribution System Enhancements	$ 7,069,995	$ 12,761,899	$ 5,691,904	81%	yes	Exh. HLR-2	39	93
Rosentrater	Downtown Network - Performance & Capacity	$ 1,150,000	$ 567,566	$ (582,434)	-51%	yes	Exh. HLR-2	77	147
Rosentrater	Elec Relocation and Replacement Program	$ 5,399,984	$ 8,575,413	$ 3,175,429	59%	yes	Exh. HLR-2	88	148
Rosentrater	Electric Storm	$ 6,000,012	$ 4,195,427	$ (1,804,585)	-30%	yes	Exh. HLR-2	95	150
Kensok	Endpoint Compute and Productivity Systems	$ 3,416,996	$ 2,815,680	$ (601,316)	-18%	yes	Exh. JMK-2	32	151
Kensok	Energy Delivery Modernization & Operational Efficiency	$ 3,449,859	$ 7,639,536	$ 4,189,677	121%	yes	Exh. JMK-2	142	155
Kensok	Energy Resources Modernization & Operational Efficiency	$ 2,679,478	$ 3,400,806	$ 721,328	27%	yes	Exh. JMK-2	153	164
Kensok	Enterprise & Control Network Infrastructure	$ -	$ 736,619	$ 736,619	100%	yes	Exh. JMK-2	43	194
Kensok	Enterprise Security	$ 1,137,498	$ 4,583,151	$ 3,445,653	303%	yes	Exh. JMK-2	202	198
Kensok	ET Modernization & Operational Efficiency - Technology	$ 2,002,429	$ 3,786,095	$ 1,783,666	89%	yes	Exh. JMK-2	80	205
Kensok	Fiber Network Lease Service Replacement	$ 1,687,126	$ 2,876,485	$ 1,189,359	70%	yes	Exh. JMK-2	91	271
Kensok	Financial & Accounting Technology	$ 2,775,001	$ 3,586,986	$ 811,985	29%	yes	Exh. JMK-2	163	278
Rosentrater	Fleet Services Capital Plan	$ 5,608,016	$ 7,251,912	$ 1,643,896	29%	yes	Exh. HLR-2	252	284
Rosentrater	Gas Above Grade Pipe Remediation Program	$ 714,000	$ 180,173	$ (533,827)	-75%	yes	Exh. HLR-2	400	285
Rosentrater	Gas Isolated Steel Replacement Program	$ 850,008	$ 2,250,494	$ 1,400,486	165%	yes	Exh. HLR-2	340	349
Rosentrater	Gas Non-Revenue Program	$ 8,500,010	$ 10,779,650	$ 2,279,640	27%	yes	Exh. HLR-2	343	367
Rosentrater	Gas Overbuilt Pipe Replacement Program	$ -	$ 604,990	$ 604,990	100%	yes	Exh. HLR-2	348	381
Rosentrater	Gas PMC Program	$ 3,799,993	$ 1,494,316	$ (2,305,677)	-61%	yes	Exh. HLR-2	352	390
Rosentrater	Gas Regulator Station Replacement Program	$ 1,000,002	$ 1,742,782	$ 742,780	74%	yes	Exh. HLR-2	355	404
Rosentrater	Gas Replacement Street and Highway Program	$ 3,500,000	$ 6,457,715	$ 2,957,715	85%	yes	Exh. HLR-2	363	417
Rosentrater	Gas Transient Voltage Mitigation Program	$ 965,000	$ 78,325	$ (886,675)	-92%	yes	Exh. HLR-2	407	431
Kensok	Generation, Substation & Gas Location Security	$ 459,001	$ 1,189,311	$ 730,310	159%	yes	Exh. JMK-2	213	447
Thackston	HMI Control Software	$ 2,550,000	$ 1,772,317	$ (777,683)	-30%	yes	Exh. JRT-4	81	452
Kensok	Identity and Access Governance	$ 418,119	$ 963,456	$ 545,337	130%	yes	Exh. JMK-2	264	455

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		(A)	(B)	(C)	(D)	(E)	(F)		(G)
Witness	**Business Case**	**2023 As-Filed TTP (1) Gross Plant**	**2023 Actual TTP (1) Gross Plant**	**Variance $** over/(under) **Gross Plant**	**Variance %** over/(under)	**$500k & +/- 10% TTP Threshold**	**Direct Filed Exhibit Exh. #**	**Direct Filed Exhibit Pg#**	**Attach-ment C Pg#**
Thackston	KF_Fuel Yard Equipment Replacement	$ 30,367,127	$ 936,000	$ (29,431,127)	-97%	yes	Exh. JRT-4	214	462
Kensok	Land Mobile Radio & Real Time Communication Systems	$ 1,005,328	$ 2,123,879	$ 1,118,551	111%	yes	Exh. JMK-2	109	489
Thackston	Long Lake Stability Enhancement	$ -	$ 1,114,534	$ 1,114,534	100%	yes			496
Rosentrater	Metro 115kV Substation	$ -	$ 545,256	$ 545,256	100%	yes			507
Thackston	Monroe Street Abandoned Penstock Stabilization	$ 899,992	$ 36,917	$ (863,075)	-96%	yes	Exh. JRT-4	226	529
Kensok	Network Backbone	$ 3,879,878	$ 1,450,064	$ (2,429,814)	-63%	yes	Exh. JMK-2	246	535
Rosentrater	New Revenue - Growth	$ 67,348,997	$ 106,963,791	$ 39,614,794	59%	yes	Exh. HLR-2	124	543
Kensok	NexGen Control System Networks	$ -	$ 694,741	$ 694,741	100%	yes			544
Thackston	Nine Mile HED Battery Building	$ -	$ 1,647,013	$ 1,647,013	100%	yes	Exh. JRT-4	234	561
Thackston	Nine Mile Powerhouse Roof Replacement	$ -	$ 840,745	$ 840,745	100%	yes			562
Thackston	Nine Mile Units 3 & 4 Control Upgrade	$ 2,000,000	$ -	$ (2,000,000)	-100%	yes	Exh. JRT-4	251	572
Thackston	Noxon Rapids Spillgate Refurbishment	$ -	$ 3,694,444	$ 3,694,444	100%	yes			590
Kensok	Outage Management System & Advanced Distribution Management S	$ 10,000,000	$ 4,655,788	$ (5,344,212)	-53%	yes	Exh. JMK-2	256	591
Rosentrater	Protection System Upgrade for PRC-002	$ 11,879,164	$ 33,015	$ (11,846,149)	-100%	yes	Exh. HLR-2	135	612
Thackston	Regulating Hydro	$ 2,961,000	$ 3,652,796	$ 691,796	23%	yes	Exh. JRT-4	127	613
Rosentrater	Saddle Mountain 230/115kV Station (New) Integration Project Phase 2	$ -	$ 17,562,125	$ 17,562,125	100%	yes	Exh. HLR-2	144	618
Rosentrater	SCADA - SOO and BuCC	$ 736,223	$ 2,586,169	$ 1,849,946	251%	yes	Exh. HLR-2	151	621
Rosentrater	Strategic Initiatives - South Landing (Catalyst) - Clean Energy Fund 3	$ -	$ 2,633,563	$ 2,633,563	100%	yes	Exh. HLR-2	275	625
Rosentrater	Substation - Asset Condition	$ 58,412,186	$ 36,908,291	$ (21,503,895)	-37%	yes	Exh. HLR-2	175	635
Kensok	Technology Failed Assets	$ 556,208	$ 1,425,606	$ 869,398	156%	yes	Exh. JMK-2	119	653
Rosentrater	Telematics 2025	$ 808,250	$ 577	$ (807,673)	-100%	yes	Exh. HLR-2	297	673
Rosentrater	Transmission - Minor Rebuild	$ 3,343,418	$ 6,179,859	$ 2,836,441	85%	yes	Exh. HLR-2	182	676
Rosentrater	Transmission Construction - Compliance	$ 1,550,000	$ 2,087,169	$ 537,169	35%	yes	Exh. HLR-2	188	700
Rosentrater	Transmission Major Rebuild - Asset Condition	$ 12,000,000	$ 16,186,511	$ 4,186,511	35%	yes	Exh. HLR-2	197	701
Rosentrater	Transmission NERC Low-Risk Priority Lines Mitigation	$ 2,499,984	$ 818,164	$ (1,681,820)	-67%	yes	Exh. HLR-2	204	704
Magalsky	Transportation Electrification	$ 3,900,000	$ 1,523,470	$ (2,376,530)	-61%	yes	Exh. KEM-2	2	707
Thackston	Upper Falls Trash Rake Replacement	$ 1,500,000	$ 2,326,061	$ 826,061	55%	yes	Exh. JRT-4	275	720

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Atlas

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Atlas business case was expected to transfer to plant approximately $2.9M and ended up transferring approximately $0.75M. This equates to approximately $2.2M less than expected in 2023.
Within the Atlas Program, resources have been prioritized to alternative Avista efforts, resulting in a surplus of labor and funding within the Atlas area. Resources and funding for the Atlas area were reallocated to the Energy Delivery Operational Efficiency Business Case, and a partial offsetting TTP variance can be seen there.
More specifically:
The ESRI Utility Network effort in being deferred to avoid rework and create capacity in the Geographic Information System (GIS) and business teams to support other enterprise initiatives, such as the Advanced Distribution Management System (ADMS), the ArcMap 10.8.1 upgrade, and the Mobility in the Field (MIF) work. The MIF efforts support the portfolio of gas compliance programs such as Leak Survey and Atmospheric Corrosion.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The following business case change requests and governance documents are attached with further details surrounding the above explanations.
CPG CR1 ($950k) Attached
CPG CR2 (550k) Attached

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The above lag in transfers-to-plant does not impact indirect offsets that have been calculated.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Stephanie Myers
9A0C6744E70F48C...

DIRECTOR SIGNATURE:

X DocuSigned by: Hossein Nikdel
E4E2D9C7EE4747F...

Atlas

1.0 CHANGE REQUEST # 1 – 05/15/23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
5/15/23	*Revised Cost*	1	$2,500,000	-$950,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
2023	Scope Change				-950k
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	2,080,000					
2025	2,080,000					
2026	2,080,000					
2027	2,080,000					
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Atlas

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Work	Amount
ESRI Utility Network	-$720,000
Mobility in the Field	-$230,000
Total Change Request	**-$950,000**

Each of the above are described below in detail:

ESRI Utility Network Application – ($720,000). Current resources have been prioritized to larger Avista efforts resulting in a surplus of labor for this project. Our current run rate reflects the need to reduce the project budget for the rest of 2023.

Mobility in the Field – Application – ($230,000). Current resources have been prioritized to alternative Avista efforts resulting in a surplus of labor for this project. Our current run rate reflects the need to reduce the project budget for the rest of 2023.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Michael Mudge	BC Owner	DocuSigned by: Mike Mudge 44C0BE3C52404B4...	May-16-2023 | 10:52 AM PDT
Hossein Nikdel	BC Sponsor	DocuSigned by: Hossein Nikdel E4E2D9C7EE4747F...	May-12-2023 | 4:53 PM PDT
Josh DiLuciano	SC Review	DocuSigned by: A3C71874F6564DB...	May-13-2023 | 5:53 AM PDT
Heather Rosentrater	BC Sponser	DocuSigned by: B327AA65D6E64F6...	May-15-2023 | 7:34 AM PDT

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

1.0 CHANGE REQUEST #2 – 10.2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
5/15/23	*Revised Cost*	1	$2,500,000	-$950,000	-$950,000	$1,550,000
10/15/2023	*Scope Change*	2	$1,550,000	-$550,000		
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	**Request Type**	**Budgeted Savings /Offsets**[1]	**Revised Savings /Offsets**	**Currently Planned TTP**[2]	**Revised TTP**
06.2023	Revised Cost				-950k
10.2023	Scope Change				-550k
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	**Budgeted Approved Amount**[3]	**Updated Funding Anticipated as a result of request**	**Budgeted Benefits /Offsets**[4]	**Revised Benefits /Offsets**	**Budgeted TTP**[5]	**Revised TTP**
2024	$2,080,000					
2025	$2,080,000					
2026	$2,080,000					
2027	$2,080,000					
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
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THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Within the Atlas Program, resources have been prioritized to alternative Avista efforts, resulting in a surplus of labor within the Atlas area. The ESRI Utility Network effort in being deferred to create capacity in the Geographic Information System (GIS) and business teams to support other enterprise initiatives, such as the Advanced Distribution Management System (ADMS), the ArcMap 10.8.1 upgrade, and the Mobility in the Field (MIF) work. The MIF efforts support the portfolio of gas compliance programs such as Leak Survey and Atmospheric Corrosion.

The ESRI Utility Network projects have additional time to complete because the ArcMap 10.8.1 version will extend to the life of the current GIS platform from 2026 to 2028. Extending the GIS applications life, known as Avista Facility Management (AFM), reduces timeline risk. AFM is the system of record for spatial electric facilities in Washington and Idaho and gas facility data in Washington, Idaho and Oregon and provides the connectivity model to support GIS engineering and analysis applications. The AFM is a cornerstone to Avista’s ability to provide responsive service across its territory.

The prioritized efforts also fall with the Energy Delivery area, and the surplus Atlas labor is being applied to the Energy Delivery Modernization and Operational Effiency (EDMOE) business case. An offsetting change request is being submitted for EDMOE.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Mike Littrel	BC Owner	DocuSigned by: Mike Littrel 9DDE7FC806184AF...	Oct-13-2023 | 11:24 AM PDT
Kelly Magalsky	BC Sponsor	DocuSigned by: Kelly Magalsky E7A0F731C49442B...	Oct-13-2023 | 10:44 AM PDT
	Steering Committee (If applicable)		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Basic Workplace Technology

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Basic Workplace Technology business case responds to five essential functions that equip our staff to optimize our business and be responsive to our customers. The five essential functions include: Employee Onboard; Contractor Onboard; Job Function Change; Exchange of equipment; and General Additions. This requires a need to keep a small amount of inventory to meet business value timeframes.

The Basic Workplace Technology Business case was originally funded for 2023 at $800,000. The demand for basic workplace technology has historically been higher than the allocation and transfers-to-plant $1.2 -$1.4 million annually and increased to $2.1 million in 2022. In 2023, this business case transferred approximately $2M, which represents an underestimated variance of approximately $1.22M. A variety of factors contributed to the additional transfer-to-plant amount:

- An increase in employee/contractor onboards. The Company experienced a higher attrition rate of employees and contractors than ever before.
- A return to the office in a hybrid working scenario requiring the addition of technology hardware (docking stations, wireless headsets, mouse/keyboard, and monitors) for a large number of employees to allow for remote and office working moving forward.
- The completion of the Rugged Refresh project, where remaining inventory transferred to this business case.
- Lenovo tablets to support the business needs of Customer Project Coordinators (CPC).
- A safety initiative to secure iPhone 15's to allow Emergency SOS communication for Lone Workers.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. Please see the following Capital Planning Group change request documents that represent changes to the plan from the filed general rate case amount. These change requests represent additional spend that was needed, that will ultimately result in additional transfers-to-plant and go into more details regarding the reasons for the additional funding:

Request - BWT CR01	Lenovo Tablets for Customer Project Coordinators (CPC)	$50,000
Request - BWT CR02	Onboarding Employees and Contractors	$250,000
Request - BWT CR03	Rugged Equipment, iPads for Electric Operations, Desktops for Drafting Department, Restock Minimum Inventory Levels for Laptops, Microsoft Surface, Standard Desktop and Accessories	$250,000
Request - BWT CR04	Return to Work, Restock Minimum Inventory Levels for Laptops, iPhones, Headsets	$450,000
Request - BWT CR05	iPhone 15's for Lone Workers (Safety Initiative)	$90,000
		$1,090,000

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The Basic Workspace technology business case enables the issuance of new technology equipment to users which allows them to perform their job functions with the greatest efficiency. The absence of this equipment would render the user unable to perform their duties effectively, resulting in significant inefficiencies. The Company does not have a method to quantify such a broad indirect saving. Therefore, no indirect savings are included.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Dave Husted
798843B6996642A...

DIRECTOR SIGNATURE:

X DocuSigned by: Alexis Alexander
EA27BABA767F467...

Basic Workplace Technology

CHANGE REQUEST CR01 02.23

Previous Requests	Requested	Approved
5-Year Plan	$800,000	$800,000
CR01	$50,000	

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
02-2023	$75,630	$50,000	$50,000	$850,000

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	2/28/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

The Basic Workplace Technology business case is seeking additional funding for an off-cycle exchange in the total amount of $50,000 to allow 12 CPC's to begin using the Lenovo X12 tablets to provide efficiencies associated with field work. The CPC's currently use Lenovo Laptop devices, which currently limits the amount of work that can be done in the field. As a result, this requires additional drive time to return to an office environment to complete the tasks associated with the design work performed out in the field. The CPC team believes that by switching to X12 Tablets it will improve the overall customer experience and productivity by supporting our employees with the tools they need to do their job in the field. Productivity improvements are estimated to be $326,418 annually.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

The CPC's currently use Lenovo Laptop devices, which currently limits the amount of work that can be done in the field. As a result, this requires additional drive time to return to an office environment to complete the tasks associated with the design work performed out in the field. One of the biggest drivers for this request is improving the overall customer experience by supporting our employees with the tools they need to do their job in the field.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

DEPLOYMENT COSTS

Model	Qty	H/W price	Accessories	Deployment Labor	Annual License/Plan	Total Cost
X12 (Capital)	13	$3300	$100	$300		**$48,100**
Netmotion License ($10/mo.) per Device (Capital)	13				$1560	**$1,560**
Cellular Data Plan - Unlimited Data ($40/mo.) per Device (Expense)	13				$6240	**$6,240**

Basic Workplace Technology

Total One-Time Cost	**$48,100**
Total Recurring Cost (Annual)	**$7,800**

The following benefits are anticipated with the change to the proposed Lenovo X12:

1. Provides the CPCs with access to the tools needed at the time the work is performed.
   - iPads are unable to access Pole # and customer contact information through Maximo or Designer.
   - Ability to design in the field eliminates errors with the ability to map a design while on the job site. A risk of waiting to note and design until the CPC returns to the office is that angles may not match with Designer and the CPC would have to make repeat trips.
   - Department uses Teams heavily and experience is poor between devices (iOS, Windows, etc.) for scheduling
   - C. Selby is having to print maps due to untrusted cert for ArcGIS on iPad.

2. Reduces travel time and the labor associated with travel time.
   - The X12 will allow the submission of Maximo orders while in the field rather than the CPC waiting to come back into the office. This allows the orders to get to a servicemember quicker and oftentimes can be tended to same day if submitted in the field (ex. Meter requests, line down, service drops).
   - CPCs must come back to office to perform certain functions (e.g., designing jobs). This is a huge time waster.

3. Allows for real-time submission and reduces lag for orders and communication and provides an overall better customer experience.
   - Reduced lag for orders submitted more real-time, ability to design, create an ESA/job packets while in the field, ultimately creates a better customer experience.
   - More real-time communication using a single standard endpoint (cancellations, reschedules, etc.)
   - Communication between office and field staff is cumbersome and can be delayed because of inconsistent capabilities across endpoint tools.

4. Allows ease of use.
   - Using OneNote/Calendar for job notes while in the field is easier due to the X12 having a keyboard (compared with iPad).

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented, including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

This request could potentially increase the amount of mobile device data plans in use, with a cost of $40 per month. However, these costs are offset by productivity savings listed in the graph below.

COST OFFSETS

Offset Category	FTE Qty	Employee Rate	Contractor Rate	Avg Rate	Task Details	Estimated Labor Efficiencies	Annual Cost	NOTES
Construction Tech Labor	6	$40.00	$50.00	$43.33	Schedules	312	$13,518.96	Labor offsets are in the form of scheduling efficiencies that the techs would realize by having all CPCs have a common computing platform that allowed for the use of MS Teams and Outlook. Estimated at hr./week per Tech.

Basic Workplace Technology

CPC Labor	13	$80.00	$0.00	$80.00	Notes/Field Activities/Designing	3900	$312,000.00	Labor offsets are in the form of efficiencies the CPCs would realize by being able to design in the field, make/share notes, and interact with Field Activities on a common platform
Purchasing Paper Planners	30	$30.00	N/A		Schedules/Notes	N/A	$900.00	
							$326,418.96	**TOTAL ANNUAL PRODUCTIVITY OFFSETS (estimated)**

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The current costs associated with travel time and labor of not having the appropriate tools readily available will outweigh the cost of the investment.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

This investment is prudent in improving the overall customer experience by supporting our employees with the tools they need to do their job in the field.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

No Change to justification narrative.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Dave Husted	BC Owner	DocuSigned by: Dave Husted 798843B6996642A...	
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	
	FP&A		

Basic Workplace Technology

1.0 CHANGE REQUEST #CR02 – 05.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
05-2023	*Revised Cost*	CR02	$850,000	$250,000		
02-2023	*Revised Cost*	CR01	$800,000	$50,000	$50,000	$850,000
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	**Request Type**	**Budgeted Savings /Offsets[1]**	**Revised Savings /Offsets**	**Currently Planned TTP[2]**	**Revised TTP**
05-2023	Revised Cost	$100k-$10M		$850,000	$1,100,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	**Budgeted Approved Amount[3]**	**Updated Funding Anticipated as a result of request**	**Budgeted Benefits /Offsets[4]**	**Revised Benefits /Offsets**	**Budgeted TTP[5]**	**Revised TTP**
2024						
2025						
2026						
2027						
2028						

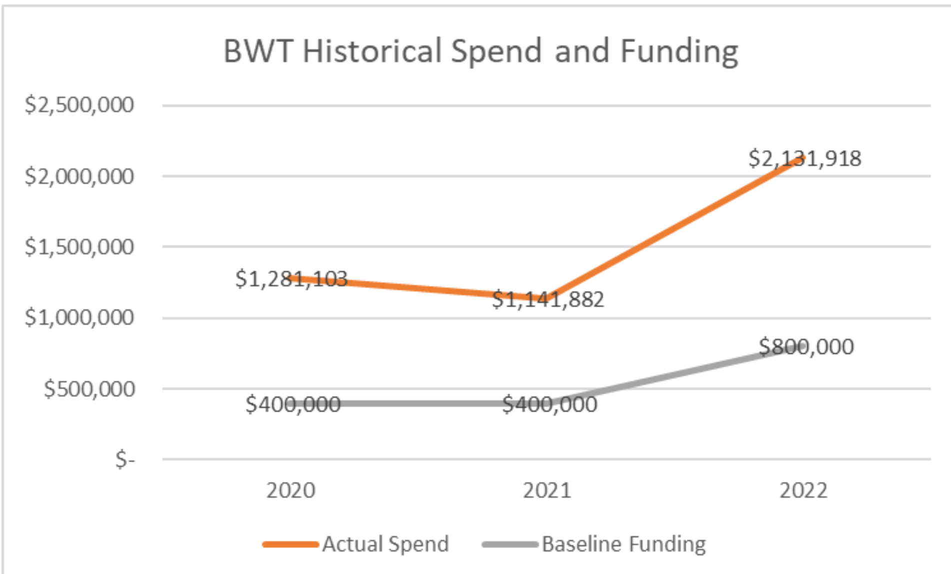
The amount requested above does not impact the outer years of this business case.

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Basic Workplace Technology

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Historically, the Basic Workplace Technology business case has exceeded its initial capital funding level, referenced in the table below. The spending trend for 2023 predicts a forecast near $1,900,000. This change request is seeking a portion of that forecasted target. A greater funding level will ensure that the business case can continue fulfilling requests throughout the year without the administrative cost and delays occurred when making additional funding requests.



If this request is not approved, the Basic Workplace Technology business case is forecast to run out of funding by the end of Q2, 2023. Without additional funding, the business case will not be able to deliver necessary technology items to workers, thereby rendering them unable to work effectively and efficiently. A greater funding level will ensure that the business case can continue fulfilling requests that align with the current fulfillment and forecast for the year.

Based on current trends, the business case is delivering 24 laptops per month. At that burn rate, inventory levels for these devices will be depleted by the end of June, 2023. In order to maintain proper inventory while factoring in product lead time of four to six weeks, a laptop order will need to be placed in early to mid-June. This order will amount to roughly $200,000 and is the primary motivation for the capital increase to meet increased employee onboarding needs. The remaining $50,000 will cover labor costs associated with the delivery of the technology equipment. Additionally, O&M costs could increase slightly due to licensing costs for new onboards.

Note: This request does not include any additional onboarding costs or onsite costs associated with the September return to work. A subsequent request may be submitted at a future date to account for this forecasted increase.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Dave Husted	BC Owner	DocuSigned by: Dave Husted 798843B6996642A...	May-12-2023 | 5:05 PM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	May-12-2023 | 5:13 PM PDT
	Steering Committee (If applicable)		

Basic Workplace Technology

1.0 CHANGE REQUEST #CR03 – 07.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
07-2023	*Revised Cost*	CR03	$1,100,000	$250,000		
05-2023	*Revised Cost*	CR02	$850,000	$250,000	$250,000	$1,100,000
02-2023	*Revised Cost*	CR01	$800,000	$50,000	$50,000	$850,000
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
07-2023	Revised Cost	$100k-$10M		$1,100,000	$1,350,000
05-2023	Revised Cost	$100k-$10M		$850,000	$1,100,000
02-2023	Revised Cost	$100k-$10M		$800,000	$850,000
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

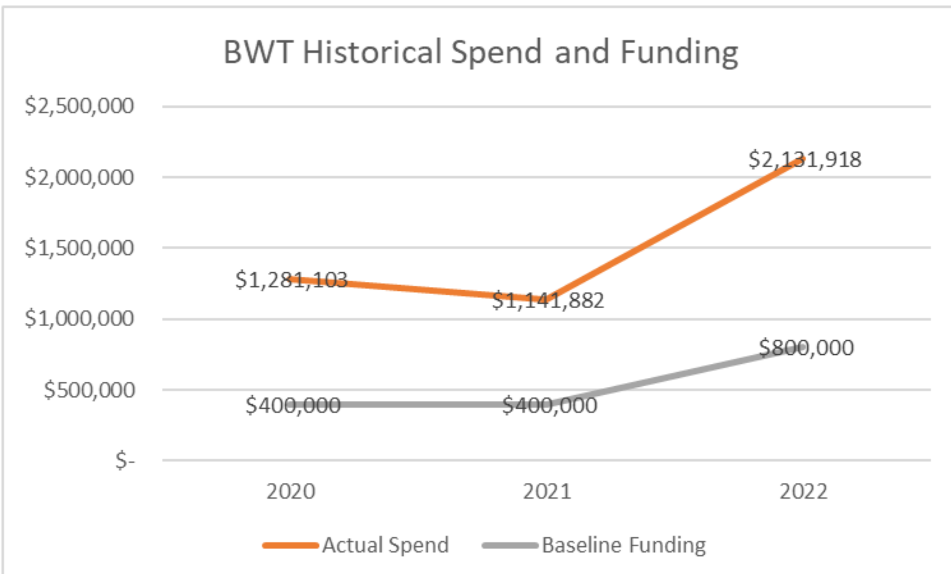
[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Basic Workplace Technology

The amount requested above does not impact the outer years of this business case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED.[6]

Historically, the Basic Workplace Technology business case has exceeded its initial capital funding level, referenced in the table below. The spending trend for 2023 predicts a forecast just over $2,000,000. This change request is seeking a portion of that forecasted target. A greater funding level will ensure that the business case can continue fulfilling requests throughout the year without the administrative cost and delays occurred when making additional funding requests.



If this request is not approved, the Basic Workplace Technology business case is forecast to run out of funding before the end of Q3, 2023. Without additional funding, the business case will not be able to deliver necessary technology items to workers, thereby rendering them unable to work effectively and efficiently. A greater funding level will ensure that the business case can continue fulfilling requests that align with the current fulfillment and forecast for the year.

At the time of this request, the Basic Workplace Technology business case has spent approximately $1,100,000 of the current funding allotment. The business case is requesting additional funding to accomplish the following:

- $57,000 transferring from the 2022 Rugged Refresh Project effort that is closing for purchase and $17,700 for the delivery, totaling $74,700 for the items below:
  - 7 full Getac Kits to align the business case back to re-order point
  - 4 iPads
  - 48 docking stations
  - Other peripheral devices

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Basic Workplace Technology

- $55,000 for 25 iPads to fulfill a request from Electric Operations to purchase and deliver a refresh of their current technology from PC's to iPads
- $41,490 to establish reorder point and deliver the Lenovo P520 desktop and associated graphics cards for potential drafting department requests
- $35,000 for the purchase and delivery of developer laptops to align with re-order point and fulfill pending requests to restock inventory at minimum levels
- $35,250 for the purchase and delivery of Surface equipment and accessories to align with re-order point and fulfill pending requests to restock inventory at minimum levels
- $17,500 for the purchase and delivery of standard desktops and accessories to align with re-order point and fulfill pending requests to restock inventory at minimum levels

The above totals roughly $241,240 in outstanding and project capital need. The request for $250,000 will allow the business case to function through July 2023 at which time we will reassess the need for additional capital.

Note: This request does not include any additional onboarding costs or onsite costs associated with the September return to work. A subsequent request may be submitted at a future date to account for this forecasted increase.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Dave Husted	BC Owner	DocuSigned by: Dave Husted 798843B8996642A...	Jul-18-2023 | 4:46 PM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Jul-19-2023 | 8:49 AM PDT
	Steering Committee (If applicable)		

Basic Workplace Technology

1.0 CHANGE REQUEST #CR04 – 09.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
09-2023	*Revised Cost*	CR04	$1,350,000	$450,000		
07-2023	*Revised Cost*	CR03	$1,100,000	$250,000	$250,000	$1,350,000
05-2023	*Revised Cost*	CR02	$850,000	$250,000	$250,000	$1,100,000
02-2023	*Revised Cost*	CR01	$800,000	$50,000	$50,000	$850,000
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	**Request Type**	**Budgeted Savings /Offsets**[1]	**Revised Savings /Offsets**	**Currently Planned TTP**[2]	**Revised TTP**
09-2023	Revised Cost	$100k-$10M		$1,350,000	$1,800,000
07-2023	Revised Cost	$100k-$10M		$1,100,000	$1,350,000
05-2023	Revised Cost	$100k-$10M		$850,000	$1,100,000
02-2023	Revised Cost	$100k-$10M		$800,000	$850,000

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	**Budgeted Approved Amount**[3]	**Updated Funding Anticipated as a result of request**	**Budgeted Benefits /Offsets**[4]	**Revised Benefits /Offsets**	**Budgeted TTP**[5]	**Revised TTP**
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Basic Workplace Technology

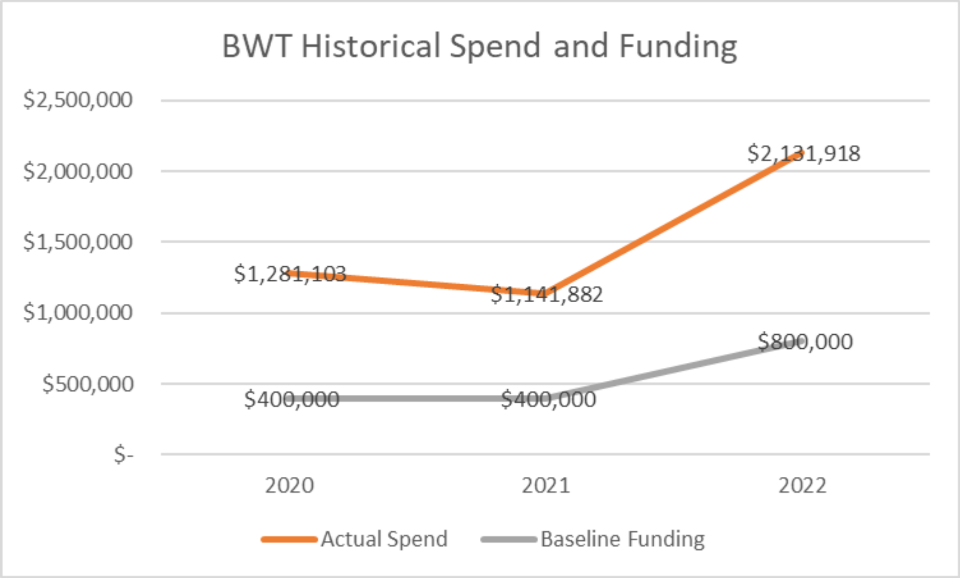
The amount requested above does not impact the outer years of this business case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Historically, the Basic Workplace Technology business case has exceeded its initial capital funding level, referenced in the table below. The spending trend for 2023 predicts a forecast just over $2,020,000. This change request is seeking the balance of the forecasted target.

A significant portion of this request will support the greater Return to Work effort that is happening starting on September 18th, 2023. To ensure the effort's success, our teams have identified technology gaps at the Mission campus as this will be the most impacted site. The goal is to backfill the gaps with missing technology items, which will ensure that returning individuals are set up for success. This not only ensures a smooth transition now, but we will also realize future savings with the majority of desk spaces configured with a similar technology suite. Ideally, this reduces ET's role/responsibility in the box move process, which could generate $50,000 in O&M savings annually.

As always, a greater funding level will ensure that the business case can continue fulfilling requests throughout the year without the administrative cost and delays occurred when making additional funding requests.



If this request is not approved, the Basic Workplace Technology business case is forecast to run out of funding before the end of Q4, 2023. Without additional funding, the business case will not be able to deliver necessary technology items to workers, thereby rendering them unable to work effectively and efficiently. A greater funding level will ensure that the business case can continue fulfilling requests that align with the current fulfillment and forecast for the year.

A significant portion of this request will be used to backfill technology gaps starting at the Mission Campus as people come back into the office more regularly starting on September 18, 2023. Current inventory levels will deplete rapidly.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Basic Workplace Technology

To ensure that all desks are properly equipped, and that returning workers can work effectively, a technology order must be placed immediately upon approval of these funds.

At the time of this request, the Basic Workplace Technology business case has spent approximately $1,165,000 of the current funding allotment. The business case is requesting additional funding to accomplish the following:

- $160,000 to purchase monitors to backfill gaps at the Mission Campus as people return-to-work and to support the remaining forecasted need through Q4 of 2023.
    - 448 units in total
        - 168 units for return-to-work effort
        - 280 units to support general burn rate and need through Q4
- $90,000 to purchase docking stations to backfill gaps at the Mission Campus as people return to work and to support the remaining forecasted need through Q4 of 2023.
    - 321 units in total
        - 133 for return-to-work effort
        - 188 units to support general burn rate and need through Q4
- $18,000 to purchase keyboard/mouse combos to backfill gaps at the Mission Campus as people return to work and to support the remaining forecasted need through Q4 of 2023.
    - 332 units in total
        - 172 for return-to-work effort
        - 160 units to support general burn rate and need through Q4
- $15,000 to purchase iPhones to fulfill the Business Case's inventory reorder point. This should fulfill remaining demand for the devices through Q4 of 2023.
- $162,000 to purchase Lenovo T14 Laptops to fulfill the Business Case's inventory reorder point. This should fulfill remaining demand for the devices through Q4 of 2023.
    - 80 units in total
- $5,000 to purchase headsets to support the remaining forecasted need through Q4 of 2023.
    - 80 units in total

The above totals $450,000 in outstanding and project capital need. The request will allow the business case to meet hardware need to through Q4 2023.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Dave Husted	BC Owner	DocuSigned by: Dave Husted 798843B6996642A...	Sep-18-2023 | 3:46 PM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Sep-18-2023 | 4:42 PM PDT

Basic Workplace Technology

	Steering Committee (If applicable)		

Basic Workplace Technology

1.0 CHANGE REQUEST #CR05 – 12.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
12-2023	*Revised Cost*	CR05	$1,800,000	$90,000		
09-2023	*Revised Cost*	CR04	$1,350,000	$450,000	$450,000	$1,800,000
07-2023	*Revised Cost*	CR03	$1,100,000	$250,000	$250,000	$1,350,000
05-2023	*Revised Cost*	CR02	$850,000	$250,000	$250,000	$1,100,000
02-2023	*Revised Cost*	CR01	$800,000	$50,000	$50,000	$850,000

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
12-2023	Revised Cost	$100k-$10M		$1,800,000	$1,890,000
09-2023	Revised Cost	$100k-$10M		$1,350,000	$1,800,000
07-2023	Revised Cost	$100k-$10M		$1,100,000	$1,350,000
05-2023	Revised Cost	$100k-$10M		$850,000	$1,100,000
02-2023	Revised Cost	$100k-$10M		$800,000	$850,000

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

The amount requested above does not impact the outer years of this business case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Basic Workplace Technology business case has been allotted $1.8 million in Capital Funding for the calendar year of 2023. Prior to this change request, spending forecasts had the Business Case generally landing within this spending limit.

This Change Request is driven by a Safety Committee initiative to ensure that Lone Workers have the tools necessary to contact Emergency Services if need were to arise. iPhone 14 and newer models are equipped with an Emergency SOS feature which allows one to communicate with local Emergency Services via text when cellular and Wi-Fi services are unavailable.

It has been recently identified that there are 57 Lone Workers with iPhone models that are not Emergency SOS-ready. Safety being the primary driver, this funds request will ensure that these workers have the latest iPhone technology in-hand.

Each qualifying Lone Worker will receive a new iPhone. Their existing iPhone devices will be returned to ET. Newer devices in good working order will be retained in spare and replacement inventory.

At the time of this request, the Basic Workplace Technology business case has spent approximately $1,735,000 of the current funding allotment. The current forecasted spend is $1,800,000 through the end of 2023. The business case is requesting additional funding to satisfy this unique Safety Committee request:

- $90,000 to support Safety Committee initiative for “Lone Workers”
  - iPhone 14 and newer devices have an Emergency SOS feature that allows communication to local Emergency Services via text when cellular and Wi-Fi services are unavailable
  - Funding will replace 57 iPhone devices for Lone Workers that do not have an iPhone 14 or newer
    - $65,000 to purchase 57 iPhones
    - $3,000 for standard iPhone accessories
    - $17,000 in labor for coordination, configuration, and delivery of devices

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Dave Husted	BC Owner	DocuSigned by: Dave Husted 798843B69966642A...	Dec-15-2023 | 11:41 AM PST
Alexis Alexander	BC Sponsor	DocuSigned by: Alexis Alexander EA27BABA767F467...	Dec-19-2023 | 4:31 AM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Cabinet Gorge Dam Fishway

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The transfer to plant for ER-6110 Cabinet Gorge Dam Fishway is related to trailing charges from project closeout and system optimization post initial startup.

During the initial operation of the Cabinet Gorge Dam Fishway in 2022, there were some fish 'take' incidents discovered as part of system operations and overtopping issues that were discovered during spill season. This resulted in a shutdown of the fishway so that project engineering could assess and design mitigation efforts. Additionally, as the system was operated in its initial start-up and run period, minor miscellaneous construction modifications were needed to optimize the operating system and implement additional habitat and personnel safety measures.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

A Business Case Funds Change Request (BCFCR) for the additional charges was submitted to the Business Case Owner and Business Case Sponsor and subsequently to the Avista Capital Planning Group in February 2023, where the additional funding was approved. At that time in February 2023, a request for an additional $500k was requested and approved bringing the new 2023 total to $735,000. The spend was actualized at $754,676, resulting in an ultimate variance of 2.6%.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revised offsets. Not completing this work would impact the Natural Resource Office's ability to re-start safe fishing operations and meet License obligations.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: DIRECTOR SIGNATURE:

x *Monica Ott* x *Bruce F. Howard*

1.0 CHANGE REQUEST # 7 – 02/10/2023

Previous Requests	Requested	Approved		
5-Year Plan	$64.2M	$64.94M		
Month - Year	**YTD Spend**	**Current Approval**	**Requested Change**	**Proposed Annual Total**
10-2019	$8,116,645	$11,750,000	($450,000)	$11,300,000
07-2020	$4,945,998	$15,100,000	($1,500,000)	$13,600,000
10-2020	$8,346,679	$13,600,000	($450,000)	$13,150,000
07-2021	$6,147,154	$16,600,000	($1,900,000)	$14,700,000
11-2021	*$9,093,187*	*$14,700,000*	*($820,000)*	*$13,880,000*
05-2022	*$4,029,681*	*$5,555,000*	*$1,479,000*	*$7,034,000*
02-2023	*$11,276*	*$235,000*	*$500,000*	*$735,000*

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	2/15/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

During the initial operation of the Cabinet Gorge Dam Fishway, there were some fish ‘take’ incidents discovered as part of system operations and overtopping issues that were discovered during spill season. This resulted in a shutdown of the fishway so that project engineering could assess and design mitigation efforts. Additionally this resulted in pushing the hydraulic field modelling and remaining construction modifications into 2023.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

Budget changes reflect construction work currently planned to take place during Q1 and Q2 of 2023. The project is at a critical stage with fish protection and associated construction modifications and the re-start fishway system before spill season 2023.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

In June 2022 the project was anticipating 2023 being primarily closeout activites until the fish injury and mortality issues were discovered. Mitigation efforts and additional labor and time associated can be reflected in the table below.

	June 2022 Est.	Feb. 2023 Est.	
LABOR TOTAL with OH Loadings	$ 49,224	$ 158,407	Extended labor for PM, NRO, and Plant Ops
500's Transportation	$ 4,100	$ 7,600	
005 Legal & 010 General	$ -	$ -	
035 Contract Support (Workforce & Volt)	$ -	$ -	
020 Professional Services	$ 178,805	$ 205,000	Additional work for fish mortality protection, material furnish, and installation
015 Construction Services	$ -	$ 274,704	
880 Materials & Equipment	$ -	$ 31,000	Dewatering Equipment
882 Large Materials & Equipment	$ -	$ -	
Freight	$ -	$ -	
937 Taxes	$ -	$ -	
530 Stores/Material Loadings	$ -	$ 2,093	Loadings on Material Purchase
532 Materials Tax/Freight Loading	$ -	$ -	
Expenses	$ 821	$ 3,937	Extended project time, and field oversight travel exp.
Admin costs & Supplies	$ 274	$ 628	Extended time and material
505 Capital Overheads A&G	$ 1,166	$ 680	Loadings on costs above
506 Cap Overhead (Generation Rate)	$ 17,492	$ 50,990	Loadings on costs above
AFUDC - N/A Suspense Project	$ -	$ -	
Contingency		$ -	
Total	**$ 251,882**	**$ 735,039**	
Approved	**$ 235,000**	**$ (500,039)**	**CPG Need**

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

Not completing this work will impact the Natural Resource Office's ability to re-start safe fishing operations.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The project team has worked with our internal resources and our contractor to expedite any procurement and construction efforts possible.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

Not proceeding with the work underway could result in additional negative impacts on protected fish and ultimately have a negative impact with our key external stakeholders and the CFSA.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The Business Case Justitification Narrative is still valid. The request is for fishery impacts encountered during initial operations.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Monica Ott	BC Owner		2/10/23
Bruce Howard	BC Sponsor		
	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Cabinet Gorge HVAC

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

In 2021, the rate case plan was to complete the Cabinet Gorge HVAC project in 2023. However, during project planning in early 2023, the team determined both engineering and construction could not be completed in 2023. The revised plan during project kick-off in Feb 2023 was to complete engineering in 2023 and construction in 2024.

The project team has completed the engineering phase and is currently moving to initiate construction.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

No change requests have been submitted and the project budget is currently tracking with the approved amount. The project is expected to Transfer to Plant late 2024.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no offsets expected as a result of this project.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Gregory Wiggins
Gregory Wiggins (Feb 28, 2024 14:53 PST)

Gregory Wiggins
Gregory Wiggins (Feb 28, 2024 14:53 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 29, 2024 07:23 PST)

David Howell
David Howell (Feb 29, 2024 07:23 PST)

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Cabinet Gorge – Station Service

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Cabinet Gorge Station Service planned to replace the aging Station Service equipment used to operate the generating plant. It is recommended that this aging equipment be replaced to ensure the continued safe operation of the plant. The planned in service date of this work has been delayed into a future year.

Please see attached 2022 Capital Additions Variance Explanation form and Business Case Funds Change Request forms submitted to the Capital Planning Group for additional discussion of the delay on this project.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Please see attached forms.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no direct offsets expected as a result of this work and therefore no revisions to offsets as a result of this change at this time.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X David Howell

DIRECTOR SIGNATURE:

X David Howell.

Cabinet Gorge Station Service

1.0 CHANGE REQUEST #1 2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
06/30/2023	*Revised Cost*	01	$5,152,937	$647,063		$5,800,000
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
06/30/2023	Revised Cost	0	0	Jan 2025	No change
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	0	$5,500,000 *	0	0	$0	$0
2025	0	$600,000 *	0	0	$0	$18,256,031

- The amount forecasted for 2024 and 2025 is not dependent on the current request.

The original forecast and transfer to plant dates/values are no longer valid because there have been several project delays. This project was put on hold between June of 2020 and July 2021, and since then, a new team was assembled to resolve key project issues and determine a path to completion. Additionally, the Load Center extended lead-time added an additional 30 week delay to the project.

	2017 - 2021	2022	2023	2024	2025	Totals
Approved Spend	$2,325,000	$4,371,800	$5,152,937	$0.00	$0.00	$11,849,737
Anticipated/Actual Spend	$2,320,511	$4,035,520	$5,800,000	$5,500,000	$600,000	$18,256,031

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Cabinet Gorge Station Service

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Recently quoted construction costs are higher than earlier project forecasts. Please reference the table below that reflects the budgeted verses recently quoted construction activities. The project team is planning to award the following construction tasks to Power City, with a planned completion this year (late Dec 2023) based on an approved contract and notice to proceed date of 7/17/23. The additional construction costs, associated overheads, and $100,000 in construction contingency total the requested $647,063 ask for 2023.

The team also considered precast emergency generator buildings, but revised the scope to use a CMU style building which resulted in a $110,000 savings and allowed these construction activities to be completed in 2023.

Cabinet Gorge Station Service Construction during 2023			
Construction Activity	**Power City Quoted Cost**	**Budgeted Cost (including project contingency)**	**Amount Above Planned Budget**
Emergency Generator Building & Installation	$936,417	$750,000	
Spillway Conduit Installation	$345,961	$200,000	
Rockface Conduit	$191,120	$160,000	
Total	**$1,473,499**	**$1,110,000**	**$363,499**

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature
Chris Clemens	BC Owner	Chris Clemens Digitally signed by Chris Clemens Date: 2023.07.05 14:41:17 -07'00'
Alexis Alexander	BC Sponsor	Alexis Alexander Digitally signed by Alexis Alexander Date: 2023.07.14 13:28:51 -07'00'

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Cabinet Gorge Station Service

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2022), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Cabinet Gorge Station Service equipment is original and was installed in 1951. The project objective is to improve the level of service, operability, reliability, and redundancy of station service power at the HED by replacing the following components; Transformers, Power Centers, Motor Control Centers, Load Centers, Emergency Generators, Emergency Load Centers, and various breakers.

This project underspent in 2022 because it was put on hold in June of 2020 and new core team was initiated in July 2021. Since the project paused over one year, the original spending forecasts and transfer to plant dates forecasted are no longer valid. The new team was assembled to resolve key project issues and determine a path to completion.

During the course of the project restart, the project team experienced material delays associated with supply chain issues and resource constraints which pushed costs to FY 2023. See referenced FCRs below.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

During FY 2022, the project team submitted two Funds Change Requests which gave back $1,000,000 due to resource availability, and the engineered component specification process had taken additional unplanned time impacting material order dates. Additionally, increased material lead-times pushed some material delivery to FY 2023 and FY 2024. See FCR 1 & 2 submitted with this explanation form.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The replacement of this equipment will result in continued safe operation of Cabinet Gorge HED, ensuring we provide reliable and affordable energy to our customers. The calculated indirect savings considers the condition of the asset, the probability of failure, the probable consequence of failure and other risk factors such as personnel and public safety, environmental impacts, and unplanned outages and repairs. Due to the delay of this project, any indirect savings will be realized in 2024 and beyond.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: DIRECTOR SIGNATURE:

x Chris Clemens x Alexis Alexander

1.0 CHANGE REQUEST #1 – 10/14/2022

Previous Requests	Requested	Approved
5-Year Plan	$0	$0

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
09-2022	$1,041,085	$5,371,800	-$500,000	$4,871,800

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	10/17/2022

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

Several tasks were delayed on this project including; panel fabrication due to resource availability and the engineered component specification process has taken additional unplanned time which has impacted material order dates. Because of these delays, spending in 2022 will be reduced. Some panel fabrication and material delivery will be shifted into 2023 and will increase funding requirements accordingly.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

Some Work will be deferred to 2023.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Additional supporting information available on request.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

No business functions will be impacted other than additional funds will be needed in 2023 to cover the funds given back in 2022.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

Funds were released to be utilized on other projects since they would not be spent on the Station Service project in 2022.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The Station Service replacement project is still a valid use of funds and is required to mitigate component failure and unplanned outages due to the system age.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Chris Clemens	BC Owner	Chris Clemens	10/17/2022

Cabinet Gorge Station Service (30405102)

1.0 CHANGE REQUEST #2 – 12/05/2022

Previous Requests	Requested	Approved
5-Year Plan	$0	$0

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
12-2022	$1,389,812	$4,871,800	-$500,000	$4,371,800

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	12/9/2022

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

Cable and conduit actual costs were lower than engineering estimates by $402,000. Additionally, cable tray material lead-time has pushed the delivery to 2023. This moved $100,000 to the 2023 budget for a total impact of -$502,000 to the 2022 budget.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

The intent of this FCR is to document the difference between estimated and actual costs, as well as noting some work has been deferred to 2023. The team has been aware of project budget risk for some time, but could not actualize the costs until quotes and lead-times were final.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Current spend end of November is $1,389,812.

Power Centers, Transformers, Wire, and additional panel material totaling $2,416,000 will arrive in December 2022, project labor and overheads will comprise the remaining expected spend for December which totals $2,982,000.

Additional supporting information available on request.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

No business functions will be impacted other than additional funding will be needed in 2023 to cover the funding requirements shifted to 2023.

Cabinet Gorge Station Service (30405102)

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

Funds were released to be utilized on other projects since they would not be spent on the Station Service project.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The Station Service replacement project is still a valid use of funds and is required to mitigate component failure and unplanned outages due to the system age.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Chris Clemens	BC Owner	Chris Clemens	12/5/22

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Cabinet Gorge Stop Log Replacement

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Stop logs are used to isolate spillway gates from the reservoir for the Cabinet Gorge Hydroelectric project. Each stop log assembly comprises nine individual stop log elements or units, which when combined, will allow dewatering of one spillway gate. Each stop log unit is predominantly a welded steel structure designed to fit inside stop log guides embedded inside a large concrete structure, and to minimize water seepage by means of a rubber seal that is compressed under unit self-weight and hydrostatic forces. Without these structures, we cannot efficiently and safely perform the upcoming spillgate work. Please see the attached Business Case Funds Change Request which was submitted to the Capital Planning Group for approval of funding changes and identifies a delay in construction which has pushed work into 2024. Therefore, the planned $1.2M transfer to plant is expected to occur at a later date.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. This includes the creation of a Steering Committee and a formal Project Team. Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance. The Project Manager will manage the project through its conclusion.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no direct offsets expected as a result of this work and therefore no revisions to offsets as a result of this change at this time.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X David Howell

DIRECTOR SIGNATURE:

X David Howell

<Project Name>

1.0 CHANGE REQUEST #02 –12/18/2023

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
12/18/2023	*Revised Cost*	02	$1,397,000	(310,000)		$1,087,000
09/11/2023	*Revised Cost*	01	$1,200,000	$197,000		$1,397,000
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
09/11/2023	Revised Cost	0	0	$1,200,000	$0
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	$0	$925,000	$0	$0	$0	$2,012,000
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Knight Construction is not able to complete all 7 stoplogs by 2023 year end as originally projected due to slower than anticipated construction throughput. The current forecasted completion is 4 stoplogs by the end of 2023. As a result, the project will need to give back $310,000 in 2023; however, will need the corresponding funding in 2024 to complete the project.

Change Request History

The CPR for the 2023 Stoplog project was based on the Noxon Stoplog project (2019) and since then, construction costs have significantly increased. knight Construction is currently fabricating the stoplogs.

- Project Change Request 1 was approved on 5/7/23 to increase total project funding to $1,750,000, from the CPR amount $1,200,000.
- Project Change Request 2 was approved on 5/30/23 to increase total project funding to $1,796,100, and move installation to 2024 with the estimated project spend below:
  - 2023; $1,485,158
  - 2024; $ 310,941
- BCFCR#1 was approved Sept 2023, with revised 2023 approved budget of $1,397,000.
- The Stoplog guide cost was unknown during the change requests above, but has since been finalized at $225,000. The financial impact to this repair work will increase total funding requirements to $2,012,000 with the estimated project spend below resulting from 2023's $310,000 giveback.

  - 2023; $1,087,000
  - 2024; $925,000

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature
Chris Clemens	BC Owner	chris clemens Digitally signed by chris clemens Date: 2023.12.19 06:02:46 -08'00'
Alexis Alexander	BC Sponsor	Alexis Alexander Digitally signed by Alexis Alexander Date: 2023.12.19 08:36:21 -08'00'

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Cabinet Gorge Unwatering Pumps

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Cabinet Gorge Unwatering Pump (ER 4227) has two projects:

- 2022 Unwatering Pump Project 30405182: This project was opened in Jan 2022 with a budget estimate of $400,000 and expected to Transfer to Plant late 2022. During project execution, the team determined the original project budget was underestimated by crews and planners. A BCFCR was initiated and approved (Nov 2022) for $485,000. Project construction was delayed because parts arrived later than planned from the supplier, and construction was split in two phases during planned plant outages. The project Transferred to Plant 1/20/23.
- 2023 Unwatering Pump Project 30405200: This project was opened in Jan 2023 with a budget estimate of $400,000 caried over from the 2022 project and expected to Transfer to Plant late 2023. During project execution, the team determined the original budget was underestimated by crews and planners. A BCFCR was initiated and approved (9/15/23) for $485,000. The project Transferred to Plant 12/15/23.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Please see change requests for the 2022 and 2023 projects attached to this email correspondence. The cost variance is summarized in the section above.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no offsets expected as a result of this project.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Gregory Wiggins
Gregory Wiggins (Feb 28, 2024 14:55 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 29, 2024 07:22 PST)

1.0 CHANGE REQUEST #01 11/14/22

Previous Requests	Requested	Approved
5-Year Plan	0	$0

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
10-2022	$409,519	$400,000	$85,000	$485,000

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	11/18/2022

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

Initial mechanical construction estimates were underestimated by planners/crews.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

If this funds request is not approved, the aging unwatering pump system will not be replaced.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Please see attached financials listed on page two of this document.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

No impacts are known.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

No other alternatives were considered. New equipment has been purchased and partially installed. The additional funds will allow the project to be finished.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

This investment will allow the Cabinet Gorge facility to operate more reliably with new sump pumps.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Chris Clemens	BC Owner		
Alexis Alexander	BC Sponsor		
	FP&A		

Change Request Financials

	Planned	Updated Forecast	Increase
Union Labor	$25,802	$56,173	$30,371
Non-Union Labor	$2,200	$2,200	$0
Professional Services	$8,745	$10,395	$1,650
Materials	$277,345	$277,345	$0
Bunkhouse meals, transportation	$6,173	$26,354	$20,181
Overheads	$66,736	$99,115	$32,379
AFUDC	$12,999	$13,418	$419
Totals	$400,000	$485,000	$85,000

1.0 CHANGE REQUEST #01 –09/11/2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
09/11/2023	*Revised Cost*	01	$400,000	$85,000		$485,000
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
09/11/2023	Revised Cost	0	0	$400,000	$485,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This should not be considered approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Cabinet Gorge Unwatering Pump - Sump 2 Project

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The CPR for the 2023 Unwatering Pump project was based on the 2022 Unwatering Pump project CPR which was underestimated by planners and crews. The 2022 Unwatering Pump project actual cost at complete was $509K. The anticipated spend for this year's project is $485,000, which is reduced from last year's project because the crew can install both pumps during one installation window.

No other alternatives were considered. The additional funds will allow the project to be completed, with construction scheduled to start on 10/23/2023.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature
Chris Clemens	BC Owner	
Alexis Alexander	BC Sponsor	
	Steering Committee (If applicable)	

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Clark Fork Settlement Agreement (CFSA)

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Each year's budget is established internally at Avista in late summer prior to the actual capital work planning conducted toward year's end and reviewed and approved by the CFSA Management Committee (MC) the following March. In addition, the ability to access project sites due to field conditions, permitting and agency staff availability impact work plan implementation each year. As a result, each year's actual spend varies to some degree compared to budget. Any changes during the year are reviewed by the CFSA MC as required, and by Avista's Capital Planning Group.

In 2023, the approved capital work planned by the signatories in March and the work that was able to be completed across 68+ projects led to a positive variance of $735,000.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

CFSA governance is multi-faceted and includes over 20 other parties, including the States of Idaho and Montana, various federal agencies, five Native American tribes, and numerous Non-Governmental Organizations. In addition, we coordinate with numerous internal stakeholders, such as GPSS and Power Supply. Many funding decisions require the approval of the CFSA Management Committee. All budget changes are reviewed by the CPG via change request.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no direct or indirect offsets associated with this project. Avista is required to comply with all terms of the License. Non-compliance would risk Avista's operational flexibility and could cause FERC to take enforcement actions, or signatories to challenge Avista's compliance. Avista would suffer reputational risks in not complying with the License and its attendant agreements.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

x Monica Ott

DIRECTOR SIGNATURE:

x Bruce F. Howard

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Control and Safety Network Infrastructure (CSNI)

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This business case administers multiple projects specifically scoped for the provisioning and expansion of network communications assets for Avista's generation, transmission, and distribution assets which support the safe and reliable energy delivery to Avista customers. Assets included in this business case have a finite lifecycle. And, given the pace of change in technology, constant threats from bad actors, growth of the Avista network and need to have suitable performance and capacity, the project work done within this program will help maintain a robust and reliable network.

For the tracking year of 2023, this business case planned to transfer-to-plant approximately $1,282,468 in project work, while actually transferring $528,524. This resulted in an under-transfer amount of approximately $753,944.

In 2023, the projects in this business case were constrained by engineering resources in this network discipline being assigned to higher priority work (i.e., HMI) and the inability to get additional trained & skilled resources contracted & assigned to this work in a timely manner. In addition, adjustments to prioritization of work altered roadmaps resulting in several projects being removed and others inserted to meet Corporate needs.

This resulted in several project schedules in the original plan to be pushed into future years and other priority projects brought into 2023. This table represents the changes:

Original 2023 Plan		**Actual Results**	
Project	**Value**	**Project**	**Value**
DNX Technology Refresh	$216,453	OATI router refresh	$112,504
Lewiston Ridge to North Lewiston Microwave Replacement	$461,038	VDR Refresh 08	$416,020
Substation Switch refresh	$561,227		
Generation Plant Out of Band Management	$43,750		
Totals	**$1,282,468**		**$528,524**

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs or reductions to the project were prudently documented and approved. The following business case change requests and governance documents are attached with further details surrounding the above explanations.

- Three change requests were submitted and approved for releasing funds totaling $730,000. The remaining difference between $730k and $753k was absorbed with existing projects:
  - Change Request 1 released $300,000 in September 2023 due to constrained resources.
  - Change Request 2 released $250,000 in November 2023 due to continued constrained resources.
  - Change Request 3 released $180,000 in December 2023 due to continued constrained resources.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The above lag in transfers-to-plant does not impact indirect offsets that have been calculated for applications such as the Avista Decision Support System or the Nucleus Energy, Trading and Risk Management System projects.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:	DIRECTOR SIGNATURE:
DocuSigned by: X Shawna Kiesbuy 3CD905A81B984C3...	DocuSigned by: X Alexis Alexander EA27BABA767F467...

Control and Safety Network Infrastructure

1.0 CHANGE REQUEST #01 – 09/2023

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
9/20/2023	*Revised Cost*	01	$1,581,758	($300,000)		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
9/20/2023	Revised Cost			$1,282,468	$1,025,251
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Control and Safety Network Infrastructure Program Business Case administers multiple projects specifically scoped for the provisioning and expansion of network communications assets for Avista's generation, transmission, and distribution assets which support the safe and reliable energy delivery to Avista customers. In 2023, the projects in this business case were constrained by engineering resources in this network discipline being assigned to higher priority work (i.e., HMI) and the inability to get additional trained & skilled resources contracted & assigned to this work in a timely manner. As such, the business case is releasing $300,000 in approved budget.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Sep-12-2023 | 11:06 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Sep-12-2023 | 3:51 PM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Control and Safety Network Infrastructure

1.0 CHANGE REQUEST #02 – 11/2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
11/15/2023	*Revised Cost*	02	$1,281,758	($250,000)		
9/20/2023	*Revised Cost*	01	$1,581,758	($300,000)	($300,000)	$1,281,758
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
11/15/2023	Revised Cost			$1,282,468	$484,664
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	$1,200,000	$1,700,000	$0	$0	$1,100,000	$2,112,000
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Control and Safety Network Infrastructure

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Control and Safety Network Infrastructure Program Business Case administers multiple projects specifically scoped for the provisioning and expansion of network communications assets for Avista's generation, transmission, and distribution assets which support the safe and reliable energy delivery to Avista customers. In 2023, the projects in this business case were constrained by engineering resources in this network discipline being assigned to higher priority work (i.e., HMI) and the inability to get additional trained & skilled resources contracted & assigned to this work in a timely manner. As such, the business case is releasing $250,000 in approved budget.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Nov-10-2023 | 9:42 AM PST
Alexis Alexander	BC Sponsor	DocuSigned by: Alexis Alexander EA27BABA767F467...	Nov-14-2023 | 4:30 AM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Control and Safety Network Infrastructure

1.0 CHANGE REQUEST #03 – 12/2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
12/20/2023	*Revised Cost*	03	$1,031,758	($180,000)		
11/15/2023	*Revised Cost*	02	$1,281,758	($250,000)	($250,000)	$1,031,758
9/20/2023	*Revised Cost*	01	$1,581,758	($300,000)	($300,000)	$1,281,758
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
12/20/2023	Revised Cost			$1,282,468	$530,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	$1,200,000	$1,900,000	$0	$0	$1,100,000	$2,150,000
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Control and Safety Network Infrastructure Program Business Case administers multiple projects specifically scoped for the provisioning and expansion of network communications assets for Avista's generation, transmission, and distribution assets which support the safe and reliable energy delivery to Avista customers. In 2023, the projects in this business case were constrained by engineering resources in this network discipline being assigned to higher priority work (i.e., HMI) and the inability to get additional trained & skilled resources contracted & assigned to this work in a timely manner. As such, the business case is releasing $180,000 in approved budget.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Dec-15-2023 | 9:24 AM PST
Alexis Alexander	BC Sponsor	DocuSigned by: Alexis Alexander EA27BABA767F467...	Dec-19-2023 | 4:32 AM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Customer Experience Platform

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

In 2023, the Customer Experience Platform business case 'Transfer to Plant' was $2,376,530 under the originally planned 'Transfer to Plant.' This variance is due to two reasons.
First, when planning the 2023 transfers to plant, the Company planned to capitalize software licenses (including the cost of the license, implementation costs, upgrades and enhancements, and the upgrades and enhancements portion of support and maintenance costs). Upon further consideration of guidance and industry practice, it was determined as of December 2023 to continue with the current practice (recording upgrades and enhancements work within support and maintenance costs as operating expense) until additional analysis can be performed and appropriate support can be obtained for capitalization of these costs, therefore the transfer to plant level ended up lower than planned..
Second, the Customer Experience Platform business case is managing and funding a key project related to the replacement of Avista's Automated Inbound Voice System and the Avista Call Center phone answering system. That project had planned to transfer to plant in 2023, but was delayed to Q2 2023 due to complexities observed in the development and delivery cycle.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The Capital Planning Group (CPG) funds change requests are attached detailing the requested allocation changes associated with the Customer Experience Platform business case.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revised offsets for this period as the delay in the inbound voice project described above isn't associated with forecasted indirect offsets, nor is the change in software licensing costs.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

3/4/2024

X Matt Halloran

Signed by: Matt Halloran

DIRECTOR SIGNATURE:

X

<Project Name>Customer Experience Program

1.0 CHANGE REQUEST #____ –

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
09/06/2023	*Scope Change*	1	$5,000,000	$775,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	**Request Type**	**Budgeted Savings /Offsets[1]**	**Revised Savings /Offsets**	**Currently Planned TTP[2]**	**Revised TTP**
09/06/2023	Scope Change	$5,000,000	$5,775,000	$6,300,009	$7,115,289
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	**Budgeted Approved Amount[3]**	**Updated Funding Anticipated as a result of request**	**Budgeted Benefits /Offsets[4]**	**Revised Benefits /Offsets**	**Budgeted TTP[5]**	**Revised TTP**
2024	No change	No change	No change	No change	No change	No change
2025	No change	No change	No change	No change	No change	No change
2026	No change	No change	No change	No change	No change	No change
2027	No change	No change	No change	No change	No change	No change
2028	No change	No change	No change	No change	No change	No change

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

<Project Name>Customer Experience Program

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Inbound Voice Project, which is replacing our current Avaya and concentrix IVR system has had both timeline and scope additions that have driven additional cost into the project. Specifically, we've asked the implementation vendor to expand their scope to include 'call center directed make a payment' functionality within the project. The additional scope, in combination with unforeseen complexities associated with implementation of a completely new inbound voice system for the call center have driven cost increases on the project. A portion of our project overrun cost can be covered by a giveback of $400,000 in our 'CFTP' business case, which has been submitted as a counterpart to this CPG ask.

Given the importance of delivering a high quality solution to handle all inbound voice calls from customers, the alternatives are limited. The CXP program evaluated stopping other projects also funded within the CXP business case, but at the time of this writing, there are only 3 active projects within the business case, 1 is the Inbound Voice, one is closing and the other offers limited cost offsets. We elected to reduce scope and give back funding within the CFTP business case to help offset this cost associated with the inbound voice project. If the choice is made to not fund this request, every month that this project is delayed, we're incurring expense costs to carry (month to month) the existing inbound voice system vendor (concentrix). That cost is approx. $24,000 monthly.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Matt Halloran	BC Owner	Matt Halloran	09/07/2023
Nicole Hydzik	BC Sponsor	Nicole L. Hydzik	09/07/2023
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

<Project Name>Customer Experience Program

1.0 CHANGE REQUEST #__2__ –

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
09/06/2023	*Scope Change*	1	$5,000,000	$775,000		
10/17/2023	*Scope Change*	2	$5,000,000	$300,000		
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
09/06/2023	Scope Change	$5,000,000	$5,775,000	$6,300,009	$7,115,289
10/17/2023	Scope Change	$5,000,000	$6,075,000	$6,300,009	$7,115,289
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	No change	No change	No change	No change	No change	No change
2025	No change	No change	No change	No change	No change	No change
2026	No change	No change	No change	No change	No change	No change
2027	No change	No change	No change	No change	No change	No change
2028	No change	No change	No change	No change	No change	No change

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

<Project Name>Customer Experience Program

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Why are we bringing this to CPG?

- We are forecasting an overspend for our business cases, so do not currently have funding to do this work.
- There is the potential for annual expense savings in 2024 and beyond if the work is completed prior to our salesforce contract renegotiation (February 2024).
- Our business and ET teams are in alignment that this work should be done, we're looking for guidance on if we attempt to complete this project prior to our re-negotiation deadline with salesforce.

Project Details - Heroku Replacement

- Heroku is a tool that enables data exchange and display in our Salesforce suite of applications.
- $300,000 estimated cost to replace Heroku and we'd outsource the technical work to a 3rd party.
- Estimated $357,000 - $450,000 annual savings* in licensing costs after completion.
    - *This would require us to reduce overall spend with salesforce licensing, not replace the spend with something else. Salesforce has stated their intention is that our annual spend is not reduced and we 'must replace'.
    - ROI - ~1 year

- If we choose to do this, we need to identify how to fund it:
    1. Deprioritize work in flight – aka 'not do something else.' The team does not recommend this.
    2. Make an ask of CPG
    3. Defer work to 2024, and extend Heroku agreement for 6 months
- **Risks**
    - Timeline: February is very tight for a project of this scale.
    - Resourcing: Resources are *very* constrained internally.
    - Salesforce Negotiation: In order to achieve/realize the savings, we must reduce our spend with salesforce by the same amount as Heroku costs.
- **Benefits**
    - Offers us cost savings potential in our salesforce contract negotiations
    - Enables us an opportunity to make system performance improvements after this work is completed.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

<Project Name>Customer Experience Program

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Matt Halloran	BC Owner	Matt Halloran Type text here	11/14/2023
Nicole Hydzik	BC Sponsor	Nicole L. Hydzik	11/15/2023
	Steering Committee (If applicable)		

<Project Name>Customer Experience Program

1.0 CHANGE REQUEST # 3

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
09/06/2023	*Scope Change*	1	$5,000,000	$775,000		
10/17/2023	*Scope Change*	2	$5,000,000	$300,000		
11/09/2023	*Revised Cost*	3	$6,075,000	$1,000,000		

Complete the following for the current request

CURRENT YEAR REQUESTS

Request Date	Offsets Impact			TTP Impact	
	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
09/06/2023	Scope Change	$5,000,000	$5,775,000	$6,300,009	$7,115,289
10/17/2023	Scope Change	$5,000,000	$6,075,000	$6,300,009	$7,115,289
11/09/2023	Revised Cost			$7,115,289	$4,540,820

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

Year	Funding Impact		Offsets Impact		TTP Impact	
	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	No change	No change	No change	No change	No change	No change
2025	No change	No change	No change	No change	No change	No change
2026	No change	No change	No change	No change	No change	No change
2027	No change	No change	No change	No change	No change	No change
2028	No change	No change	No change	No change	No change	No change

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

<Project Name>Customer Experience Program

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Effective July 1, 2023 the Company changed its accounting methodology regarding capitalization of licenses. This change impacts several capital business cases including this business case Customer Experience Program. We are requesting an increase in funding due to this change in the amount of $1,000,000. Please see the attached memo from project accounting for more detail regarding this change in accounting methodology.

This change request covers licenses associated with the following software applications: SALESFORCE COM INC.

The CXP Business Case TTP has been reduced from $7,115,289 to $4,540,820 due to the need delay the CXP: Inbound Voice Channel Refresh – 09907022 project release from December 2023 to February 2024. Delaying the delivery date allowed us to address unforeseen challenges, ensuring a higher-quality outcome for our customers. It provided the necessary time for thorough testing, refining and ultimately delivering a more robust and reliable product.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Matt Halloran	BC Owner		3-7-24
Nicole Hydzik	BC Sponsor	Nicole L. Hydzik Digitally signed by Nicole L. Hydzik Date: 2024.03.07 11:44:59 -08'00'	
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Customer Facing Technology Program

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

In 2023, the Customer Facing Technology Program business case 'Transfer to Plant' was $922,273 under the originally planned 'Transfer to Plant. When planning the 2023 transfers to plant, the Company planned to capitalize software licenses (including the cost of the license, implementation costs, upgrades and enhancements, and the upgrades and enhancements portion of support and maintenance costs). Upon further consideration of guidance and industry practice, it was determined as of December 2023 to continue with the current practice (recording upgrades and enhancements work within support and maintenance costs as operating expense) until additional analysis can be performed and appropriate support can be obtained for capitalization of these costs, therefore the transfer to plant level ended up lower than planned.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

No cost overruns were associated with this business case for 2023. More specifically, the total capital spend for this business case came in under budget for 2023. If a cost overrun were to occur, the business case leadership team would seek approval from both the Customer Technology Solutions Governance group and the Avista Capital Planning Group.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revised offsets for this period as the software licensing costs are not associated with forecasted indirect offsets included within the business case.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

3/4/2024

X Matt Halloran

Signed by: Matt Halloran

DIRECTOR SIGNATURE:

X

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Customer Transactional Systems

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

In 2023, the Customer Transactional Systems business case 'Transfer to Plant' was $910,499 under the originally planned 'Transfer to Plant.' When planning the 2023 transfers to plant, the Company planned to capitalize software licenses (including the cost of the license, implementation costs, upgrades and enhancements, and the upgrades and enhancements portion of support and maintenance costs). Upon further consideration of guidance and industry practice, it was determined as of December 2023 to continue with the current practice (recording upgrades and enhancements work within support and maintenance costs as operating expense) until additional analysis can be performed and appropriate support can be obtained for capitalization of these costs, therefore the transfer to plant level ended up lower than planned.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

No cost overruns were associated with this business case for 2023. More specifically, the total capital spend for this business case came in under budget for 2023. If a cost overrun were to occur, the business case leadership team would seek approval from both the Customer Technology Solutions Governance group and the Avista Capital Planning Group.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revised offsets associated as the business case does not include forecasted offsets. This is because the business case addresses a required investment to implement updates from software providers and regular security patches to ensure customer data is protected. Additionally, this investment is required to meeting business requirements to service Avista customers (such as billing and customer support), maintain compliance with state and federal rules and regulations, and to meet the requests of our third-party partners.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

3/4/2024

X Matt Halloran

Signed by: Matt Halloran

DIRECTOR SIGNATURE:

X

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Data Center Compute and Storage

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Data Center Compute and Storage Systems business case is a program of investments in server and storage technology required to process and store massive amounts of data to automate and enable business processes that support our gas and electric customers across our service territory.

This business case was expected to transfer-to-plant approximately $2M and ended up transferring around $3.87M, resulting in an underestimated transfer-to-plant amount of approximately $1.87M.

The primary reason for the underestimated transfer-to-plant amount is due to the increased hardware storage needs and costs for Primary and Secondary storage. Non-Data Center Compute and Storage Systems projects have increased the required storage capacity and these increases were not included in the Storage Refresh budget. The largest requirement for storage was driven by the Meter Data Management (MDM) Platform, contributing to the need for increased storage which also increased the costs and contributed to the underestimated transfer-to-plant amount.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. Please see the following Capital Planning Group change request documents that represent changes to the plan from the filed general rate case amount. These change requests represent additional spend that was needed, that will result in additional transfers-to-plant and go into more details regarding the reasons for the additional funding:

Request - CR01	New cabinets and Power Distribution Units (PDUs) for the off-site Disaster Recovery location as part of the move to the new site location	$140,000
Request - CR02	Increased hardware storage needs and costs for Primary and Secondary storage.	$2,911,986
		$3,051,986

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

By maintaining a high level of enterprise network storage integrity and reliability in the CORP environment, refreshing ageing NetApp storage is a critical component. Reliability, functionality, and security risks significantly increase when technology is in service beyond its designed life cycle. By investing in the NetApp storage refresh within the five-year refresh cycle, the additional expense of $165,842 (per year) would not be incurred since the extended support for 12 months would no longer be needed.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

DocuSigned by:

X Walter Roys

28978793A9C64D0...

DIRECTOR SIGNATURE:

DocuSigned by:

X Alexis Alexander

EA27BABA767F467...

1.0 CHANGE REQUEST #CR01– 04.2023

Previous Requests	Requested	Approved
5-Year Plan	$2,819,942	$2,719,942
CR01	$140,000	

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
04-2023	$100,287	$2,719,942	$140,000	$2,859,942

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	4/21/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

Avista utilizes an off-site Disaster Recovery location to back up important data and systems so that in the event of the primary Data Center location going offline, seamless continuation of work and resource functions could continue with limited downtime. The current Disaster Recovery location is in San Jose, however Avista was recently notified that this location is shutting down and our disaster recovery equipment and services will need to move to a new location. Avista is planning to take advantage of this move to upgrade and refresh some of the existing infrastructure used by the Disaster Recovery location, this includes new cabinets and Power Distribution Units (PDUS).

The current PDUs at San Jose are well past their useful life as well and are causing issues, such as the need to restart them frequently. Some are also unable to join the network, which results in alerting functions being disabled. This presents risk that in the event of a disaster scenario, our disaster recovery infrastructure may not function as fully designed, which could result in downtime for critical business applications. This project will refresh the current PDUs, as well as install where applicable single power supply PDUs (or Automatic Transfer Switches). These devices would allow a device to remain powered on should a PDU malfunction.

This additional amount of $140k will transfer-to-plant (TTP) in 2023 and will increase our TTP amount originally budgeted.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

PDUs that are past their useful life and are starting to malfunction create risk that disaster recovery and high availability services may not be available when needed. This could result in downtime for applications that could be critical to the delivery of electric and natural gas to customers. Replacing these PDUs will reduce this risk, and timing this refresh to occur while the Disaster Recovery data center is completing a move to a new location will decrease the amount of downtime for the Disaster recovery data center.

Additionally, If this work is not completed, it would result in a lack of redundancy during the Disaster Recovery data center move, which could result in the risk of additional downtime should the primary data center experience an issue.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

The standard life span of a PDU is 100,000 hours (approximately 11 years). The majority of the PDU's in use today are currently around 13-15 years old and some at 5-7 years old. PDU's run past that timeframe have a high risk of failure. The manufacturer only offers a 2 year warranty.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

Most of the cabinets at the current location are fully depreciated. The purchase of new cabinets will allow set up and installation to occur prior to moving physical infrastructure from the old location to the new location, thereby decreasing the amount of time needed for the move and not incurring additional O&M for the move.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The alternative to this request would be to move the existing PDU devices that have had a history of causing issues, restarts, etc due to being past their useful life In addition, the same cabinets could be used and moved, however, this would increase the time needed for the disaster recovery data center move due to the need to also move cabinets. Neither of these alternatives were the best option given the timing and issues.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

This investment is still prudent.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

Justification narrative is still valid.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Walter Roys	BC Owner	DocuSigned by: Walter Roys 28978793A9C64D0...	Apr-17-2023 | 4:32 PM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Apr-18-2023 | 10:30 AM PDT
	FP&A		

Data Center Compute and Storage Systems

1.0 CHANGE REQUEST #CR02 – 06.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
06-2023	*Revised Cost*	CR02	$2,859,942	$2,911,986		
04-2023	*Revised Cost*	CR01	$2,719,942	$140,000	$140,000	$2,859,942
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	**Request Type**	**Budgeted Savings /Offsets[1]**	**Revised Savings /Offsets**	**Currently Planned TTP[2]**	**Revised TTP**
06-2023	Revised Cost	N/A	-$165,842	$2,859,942	$5,771,928
04-2023	Revised Cost	N/A	N/A	$2,719,942	$2,859,942
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	**Budgeted Approved Amount[3]**	**Updated Funding Anticipated as a result of request**	**Budgeted Benefits /Offsets[4]**	**Revised Benefits /Offsets**	**Budgeted TTP[5]**	**Revised TTP**
2024	$5,159,903*	$2,247,917*	N/A	N/A	$5,159,903*	$2,247,917*
2025						
2026						
2027						

∗ This budget has not yet been approved, the amount listed is based on the requested funding amount.

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.

[2] The information for the current year should be obtained from the *General Information* section of the Business Case.

[3] The information for the current year should be obtained from the *General Information* section of the Business Case.

[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.

[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

2028						

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

To maintain a high level of enterprise network storage integrity and reliability in the CORP environment, refreshing ageing NetApp storage is a critical component. Reliability, functionality, and security risks significantly increase when technology is in service beyond its designed life cycle. NetApp storage has a five-year refresh cycle and at this time Corp Storage clusters are beyond their life cycle and scheduled for refresh. Non-Data Center Compute and Storage Sytems projects have added storage capacity that were not included in the Storage Refresh budget, largely the Meter Data Management (MDM) Platform, contributed to the need for increased storage which also increased the costs. Increased hardware costs beyond the original forecasted amount have required the request for additional funds.

$1,812,000 for Primary Storage + tax (8.9%) = $1,973,268
<u>$862,000 for Secondary Storage + tax (8.9%) = $938,718</u>
Total NetApp Costs for Primary and Secondary Storage: $2,911,986

Currently, these Primary and Secondary Storage costs of $2,911,986 are budgeted in the 2024 forecast. If these costs are incurred in 2023, then the 2024 forecast would be reduced by $2,911,986. Additionally, the $2,911,986 requested in 2023 is targeted to fully TTP at $2,911,986 in 2023.

If these additional funds are not fulfilled in 2023, additional expense would be incurred to extend support for another 12 months (and potentially through Dec 2026 if needed) to allow for primary and secondary backup. Additionally, there is increased risk as the equipment ages and will incur increased operational costs.

The additional expense of $165,842 (per year) to extend support for 12 months would be due September 30, 2023.

However, if the Primary and Secondary Storage costs are funded for 2023, then no additional expense of $165,842 would incur.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Walter Roys	BC Owner	DocuSigned by: Walter Roys 28978793A9C64D0...	Jun-19-2023 | 9:26 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Jun-20-2023 | 10:11 AM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Data Center Compute and Storage Systems

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Digital Grid Network

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This business case includes network communications technology that establish a reliable, secure and supportable mix of private and third-party solution that compose the FAN (Field Area Network), including mesh devices using unlicensed wireless bands installed throughout the service territory and devices that leverage commercial LTE communications systems.

For the tracking year of 2023, this business case planned to transfer-to-plant $2,121,419 in project work, while actually transferring $3,485,617. This resulted in an over-transfer amount of $1,364,198. This business case was challenged by long lead times for product which delayed project work resulting in increased costs as well. In addition, securing resources with needed technical skills to support the network team took longer than expected. Finally, to support changing priorities, projects were adjusted to meet Corporate objectives. The result of these impacts are as follows:

Project	Original Plan	Actual Result
Nokia Headend System Implementation	$1,213,070	$2,344,101
Wireless Mesh Refresh Packages	$908,349	$1,064,899
Trailing Costs/Other Minor Work	$0	$76,617
Totals	**$2,121,419**	**$3,485,617**

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. The following business case change requests and governance documents are attached with further details surrounding the above explanations.

- 01 BCFCR - $1M Increase
- 02 BCFCR - $35k Increase
- Nokia Headend System – Project Management Plan
- Nokia Headend System – Project Change Request

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are not any changes to the indirect offsets that would be calculated for this business case based on the over transfer amount listed above.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Shawna Kiesbuy
3CD905A81B984C3...

DIRECTOR SIGNATURE:

X DocuSigned by: Alexis Alexander
EA27BABA767F467...

1.0 CHANGE REQUEST #01 – 2023.05.17

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
5/17/2023	*Scope Change*	01	$2,296,380	$1,000,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
5/17/2023	Scope Change	$0	$0	$5,058,884	$5,058,884
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Digital Grid Networks Program Business Case includes network communications technology that establishes a reliable, secure, and supportable mix of private and third-party solutions that compose the FAN (Field Area Network), including mesh devices using unlicensed wireless bands installed throughout the service territory and devices that use commercial LTE communications systems. Since five-year planning was completed last year, significant project work related to AMI WA support and expansion along with new projects to support midline devices and HMCs in the field (either to expand coverage or place devices where we do not have them today), have been added to the portfolio causing the original approved budget to be insufficient to fund current inflight work.

Since the ongoing support and expansion of AMI WA is mandatory for Avista's daily operations, limited alternatives were reviewed. Alternatives include:

- Slowing down project work across the portfolio of projects until the budget is met at which point all project work is stopped for the remainder of 2023.
- All new projects related to AMI WA support and expansion are stopped until 2024 which would result in no data capture from new AMI meters deployments hampering our ability to support customer needs.

In addition, new projects to support midline devices and HMCs in the field (either to expand coverage or place devices where we do not have them today) is a must to support the control and safety monitoring of midline devices as fire season approaches. Alternatives include:

- Slowing down project work across the portfolio of projects until the budget is met at which point all project work is stopped for the remainder of 2023.
- All project work related to the expansion of midline devices and HMCs in the field would stop until 2024 which would result in a lack of control and visibility in areas of our distribution system as we head into fire season.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	May-29-2023 | 11:14 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Jun-01-2023 | 12:08 PM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Digital Grid Network

1.0 CHANGE REQUEST #02 – 2023.10.18

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
10/18/2023	*Revised Cost*	02	$3,296,380	$34,894		
5/17/2023	*Scope Change*	01	$2,296,380	$1,000,000	$1,000,000	$3,296,380
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
10/18/2023	Revised Cost	$0	$34,894	$3,700,000	$3,756,266
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	$2,800,000	$73,623	$0	$73,623	$3,774,455	$3,848,078
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Effective July 1, 2023 the Company changed its accounting methodology regarding capitalization of licenses. This change impacts several capital business cases including this business case. We are requesting an increase in funding due to this change in the amount of $34,894. Please see the attached memo from project accounting for more detail regarding this change in accounting methodology.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Oct-18-2023 | 11:25 AM PDT
Wayne Manuel	BC Sponsor	DocuSigned by: Wayne Manuel F1A34ACB278F4F7...	Oct-19-2023 | 3:39 PM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Change Request Form

Project Name: DGN Nokia Headend System Implementation
Clarity Project ID: PR00016633
Acctg Project #: 09906804
Business Case Name: Digital Grid Network (DGN)
ER/BI: 5156-56N09
Risk or Issue ID: RSK00007562, RSK00007850
Constraint(s): Scope, Schedule, and Funding
Submit Date: 07/25/2023

1 Back.

Project Sponsor(s):	Shawna Kiesbuy	**Business Case Owner(s):**	Shawna Kiesbuy, Jim Corder
Program Manager:	Elizabeth Arnold	**Project Manager:**	Gary Pellham
Steering Committee Members:	Jim Corder, Mike Busby, Shawna Kiesbuy, Kaitlyn Richardson, Bryan Rask	**Primary Product Owner:**	Tatiana Plett
		Other Stakeholders:	

2 Summary of Change(s)

An increase to schedule and funding, as well as a change to scope, is requested due to reasons outlined below:

Schedule: A change to schedule is requested to extend the closing date to April of 2024. The project schedule has been delayed due to telecom shop resource availability, lengthened equipment lead-times and a lack of network engineering resources with Nokia experience that were needed to lead project work. Additional delays were incurred due to the intricate design, and as was recommended in the July SteerCo, the project will provide a six-month warranty period due to project complexity.

Funding: An increase of $481,507 is requested. Additional hours for engineering work, project support and AFUDC are required. The headend design for this project has been significantly more intricate than originally planned. Additionally, the July SteerCo recommended a six-month warranty period due to project complexity.

Scope: The steering committee has asked the project to move the effort of migrating deployed SAR-HMCs to First Net to the Wireless Mesh Refresh Package 3 VDR – 09907137 project. This will allow this project to finish sooner and accumulate fewer overhead costs while the Mesh Refresh Package 3 project will use the same resources and commit to more of the same type of replacement work it is already committed to doing in achieving this deliverable. Keeping this work in this project could result in significant delays as the migration of HMCs is considered secondary to the importance of deploying new devices. Furthermore, the 116 HMCs that will be refreshed are still operating on the SCADA APN network and are not currently down.

2.1 Business Impact

Installation of the Nokia Headends is required to deploy new Nokia SAR-Hmc's to replace the end-of-life Tropos radios which are used to communicate with mid-line devices that are used to control our electrical grid. Failure to approve this change request may result in additional delays to schedule and a change in project priority, adding to the PMO costs for project manager, coordinator, product owner, scrum master and additional program oversight associated with monitoring and managing the projects. The continued engagement of professional services (SCI) would also be jeopardized if this request was not approved. An extension of schedule and additional funding will allow continuing efforts toward providing safe and reliable infrastructure. Failure to approve this change request may also have an unintended negative impact on other projects currently relying on the success of this project, including the DGN Mesh Package 3 Refresh and NCSN SCADA Comms Refresh projects.

3 Scope Change Details

Use Cases	Existing Deliverables	Changes to Deliverables
1-6	Lab Deploy: (1) VSR-NGE, (2) Aggregator Nodes 7705 SAR-18 and (2) 7705 SAR-Hmc.	No change
1-6	Production Deploy: (2) VSR-NGE, (4) Aggregator Nodes 7705 SAR-18 and (2) 7705 SAR-Hmc.	No change
1-6	Aggregate Nokia Hmc Network Group Encryption transport connections at both CDA and AVA.	No change
1-6	Integrate lab and production Nokia VSR/Head-Ends to Nokia NSP management platform.	No change
1-6	Migrate all deployed SAR-Hmcs to First Net.	The scope of this work will be moved out of this project and into the Wireless Mesh Refresh Package 3 VDR – 09907137 project.
1-6	Reconfigure the First Net APN secondary Headend from San Jose to CDA.	No change
1-6	Provide vendor delivered training to delivery and operations engineers and technicians.	Since training is an expense, it will be moved out of this project and provided via an expense project.

3.1 Where Will Technology Be Deployed

- Avista headquarters (Mission datacenter) - Spokane, WA
- Avista headquarters (Lab 05) – Spokane, WA
- Coeur D'Alene office – Coeur D'Alene, ID

4 Schedule Change Details

Major Milestone Descriptions	Target Completion Dates (MM/YY)	
	Planned Date	Revised Date
Project Initiation – *Actual approval date*	05/20	
Scope approval w/VROMs (Go / No-go decision point) – *Actual approval date*	06/22	
ETER review and approval actual date – *Actual approval date*	11/22	04/23*
PMP / Approval to Execute – *Planned or Actual approval date*	10/22	
Transfer to Plant (TTP) / Go-Live – *Planned date*	12/22	09/23
Forecasted Close Date – *Planned date*	04/23	04/24

*Note: A total of 3 ETER dates were planned for this project. The first was to focus on SAR18 (18-slot Service Aggregation Router) deployment at two sites. The second was to install the VSRs (Virtual Service Routers), and the third was the implementation of 3 HMC routers to replace the lost functionality of failed Tropos radio solutions.

5 Compliance and Controls

Area	Required (Y/N)
Compliance Impact Assessment (contact: Jennifer Massey)	N
Business Continuity Plan/Business Impact Assessment (contact: Erin Swearingen) - *Always Required (excluding enhancement packages)*	Y
Reliability Compliance (NERC) (contact: Erin McClatchey)	N
SOX Business Controls Impact Assessment (contact: Stacey Wenz)	N
SOX Application Pre and Post Implementation Assessment (contact: Matt Williams)	N
Security Impact Assessment (SIA) formally known as Computer Controls Impact Assessment	Y

(CCIA) (contact: Shanna Pagniano) - *Always Required*	Y
PCI (Payment Card Industry) Compliance Assessment (contact: Shanna Pagniano)	N
Network Impact Assessment (contact: Douglas Michaud) - *Always Required*	Y

6 Funding Change Details

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Labor:	$587,958	$541,233	$1,129,191
Non-ET Labor:	$0	$0	$0
Product:	$745,120	($31,840)	$713,280
Professional Services:	$331,711	($58,904)	$272,807
Other:	$81,851	($29,377)	$52,474
AFUDC:	$56,324	$60,395	$116,719
Total:	**$1,802,964**	**$481,507**	**$2,284,471**

7 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories**. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service, and removal and decommissioning of retired assets.

Accounting Asset Category	Installation *(107600)*		Removal *(108000)*	Total ($)
	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Hardware (FERC Account 391)	$0	$0	$0	**$0**
Communications Equipment (FERC Account 397)	$713,281	$1,571,091	$99	**$2,284,471**
Software (FERC Account 303)	$0	$0	$0	**$0**
Estimated Total Capital Cost:	**$713,281**	**$1,571,091**	**$99**	**$2,284,471**

Project Management Plan

Project Name: DGN Nokia Headend System Implementation
Clarity Project ID: PR00016633
Acctg Project #: 09906804
Business Case Name: Digital Grid Network
ER/BI: 5156-56N09
Submit Date: 11/04/2022

1 Key Roles & Project Information

Project Sponsor(s):	Jim Corder	**Business Case Owner(s):**	Shawna Kiesbuy
Program Manager:	Elizabeth Arnold	**Project Manager:**	Gary Pellham
Steering Committee Members:	Jim Corder, Mike Busby, Shawna Kiesbuy, Kaitlyn Richardson, Bryan Rask	**Primary Product Owner:**	Tatiana Plett
		Other Stakeholders:	Craig Figart

2 Project Overview

2.1 Business Need

The implementation of a Nokia Headend system is necessary to support the full functionality of the new Nokia SAR-HMC and FirstNet network. This project resides in the DGN business case as it supports the SAR-HMC deployment which is replacing TropOS devices.

Construction of redundant head-end architectures for the termination of secure connections from all Nokia SAR HMC cellular routers greatly increases reliability and efficiency of SCADA and all other communications to and from the HMC network. The Head End architecture also securely and efficiently aggregates traffic from the HMC-connected endpoints and forwards it to the SCADA network at Avista control centers in Spokane and Coeur d'Alene in a secure manner

2.2 Who Benefits?

Avista's operations teams will benefit from increased network reliability and performance connecting electric distribution endpoints that integrate into the Distribution Management System, Outage Management System, and advanced metering systems. Operations will also benefit from increased efficiency of HMC deployment and support.

Avista customers will benefit with a network supporting faster distribution grid fault location, isolation and recovery times, and the capability for expanded grid automation and system situational awareness by grid operators. Avista customers and operations teams will benefit with a network platform supporting existing and future use cases.

- Avista customers will benefit with continued support for Distribution Automation and fast power restoration capabilities it provides.
- Distribution Dispatch and System Operations benefit with remote grid operation capabilities.
- Avista benefits by continued support for Distribution Automation via the Distribution Management System and efficient delivery of energy to its customers.
- Network Operators will benefit by having fully supported network components and integration with a Network Management platform enabling efficient management and health monitoring

2.3 Strategic Focus Area

Primary Focus Area *(select one)*		
☐	**Our Customers**	▪ Mature our customer experience, both internal & external ▪ Partner with communities & customers to support economic recovery & growth ▪ Address evolving customer needs by offering products, services, & energy efficiency solutions
☐	**Our People**	▪ Mature safety systems to promote learning & reduce risks ▪ Invest in our people supporting their development, resiliency & well-being ▪ Strengthen equity, inclusion & diversity within systems, practices & behaviors
☒	**Perform**	▪ Continuously improve our generation & delivery of safe, reliable, clean, & affordable electric & natural gas service ▪ Achieve stated financial objectives through focused cost management, timely rate recovery, business transformation, & unregulated business development
☐	**Invent**	▪ Advance our electric & natural gas clean energy strategy with equity, affordability, & reliability ▪ Cultivate innovation skills & interest to support transformation & growth ▪ Pursue a reimagined utility of the future with optimized bi-directional grid & new rate-making paradigm

2.4 Who Is Impacted By This Project?

System, processes, and/or teams	How the system, process, and/or team is impacted
Network Engineering	• Network design and support processes and procedures will be modified with the new field network solution. • Field device management will be integrated with the Nokia Network Management system. • New design documentation and written processes and procedures will need to be developed.
SCADA	Modifications to the network design will require network configurations at the SCADA headend and Local Area Network.
System Protection	Network design diagrams will need to be updated as part of the documentation process and new SEL-3622 configuration files. The addition of SEL 3622 equipment will increase security.
Distribution Engineering	• New construction standards will be required for installing devices in the field. • Develop and deploy field installation packages.
Network Operations	NetOps will be required to provide 24/7 operational support for the devices and backhaul systems
Distribution Operations	Distribution Operations will be required to identify and approve deployment windows and conduct operational testing.
Supply Chain	Supply Chain will procure equipment and manage vendor relations as needed.
Telecom Ops	Provisioning, commissioning, and installation of Nokia SAR-Hmc devices in the field.
Relay Shop	Configuration and installation and of SEL-3622 devices in the field.

3 Project Requirements and Deliverables

3.1 Use Cases

1. Operations needs to be able to monitor and manage communications within endpoint devices that collect and send endpoint data over the secure communication paths to the Intelligent Electronic Devices which are used to control the energy delivery system, providing improved reliability and a reduced number of power outages while maximizing capacity utilization and life span

2. Operations needs to collect and send endpoint data over the private backhaul to the data management systems at Avista.
3. Operations needs to monitor and manage Distribution Automation (DA) device communication with the Distribution Management System (DMS) which supports Fault Detection Isolation and Restoration (FDIR) and minimizes customer impact of electric distribution outages.
4. Operations needs communication between DA and the DMS to support Interval Volt-Var Control (IVVC) and maintenance of Avista's Energy Efficiency initiatives.
5. Real-time network communications required to provide engineering access for remote control and programmability of the DA field devices.
6. The communications technology is needed to increase the overall security of the system, improve network visibility, and provide effective management of operational SAR-Hmc devices.

3.2 Project Deliverables

Use Case	Description
1-6	Lab Deploy: (1) VSR-NGE, (2) Aggregator Nodes 7705 SAR-18 and (2) 7705 SAR-Hmc.
1-6	Production Deploy: (2) VSR-NGE, (4) Aggregator Nodes 7705 SAR-18 and (2) 7705 SAR-Hmc.
1-6	Aggregate Nokia Hmc Network Group Encryption transport connections at both CDA and AVA.
1-6	Integrate lab and production Nokia VSR/Head-Ends to Nokia NSP management platform.
1-6	Migrate all deployed SAR-Hmcs to First Net.
1-6	Reconfigure the First Net APN secondary Headend from San Jose to CDA.
1-6	Provide vendor delivered training to delivery and operations engineers and technicians.

3.3 What Will Not Be Delivered?

Description	Reason for being out of scope
Additional SAR-HMC's will not be deployed	Will be deployed in other projects.

3.4 Where Will Technology Be Deployed?

- Avista headquarters (Mission datacenter) - Spokane, WA
- Avista headquarters (Lab 05) – Spokane, WA
- Coeur D'Alene office – Coeur D'Alene, ID

4 Major Milestones

Description	Actual or Planned Completion Date (MM/YY)
Project Initiation – *Actual approval date*	01/01
Scope approval w/VROMs (Go / No-go decision point) – *Actual approval date*	06/22
ETER review and approval actual date – *Actual approval date*	11/22
PMP / Approval to Execute – *Planned date*	10/22
Transfer to Plant (TTP) / Go-Live – *Planned date*	12/22
Forecasted Close Date – *Planned date*	04/23

5 Assumptions, Risks, Constraints, and Dependencies

5.1 Assumptions

The following assumptions have been made:

a) The technology to meet the business and technical requirements is available and fully supported by the manufacturer.
b) Avista has the engineering resources available when needed to support the project.
c) Receiving the new equipment on a timely manner so engineering and testing can get started.
d) Having a services agreement with Nokia for support during testing.

5.2 Risks

a) Resource constraints may delay project timeline.
b) Long lead times from the manufacturer may affect the project's schedule.
c) Headend requirements discovered during planning may present changes to initial scope, schedule or budget.
d) High complexity of the project.
e) Unforeseen issues during implementation.

5.3 Constraints

- Given a fixed schedule, we will choose a scope and adjust resources as necessary.

Flexibility Matrix	Low Flexibility	Medium Flexibility	High Flexibility
Scope		x	
Schedule	x		
Budget			x

- *Note: Quality is always expected to be high*

5.4 Dependencies – N/A

6 Compliance and Controls

Area	Required (Y/N)
Compliance Impact Assessment (contact: Jennifer Massey)	N
Business Continuity Plan/Business Impact Assessment (contact: Erin Swearingen) - *Always Required (excluding enhancement packages)*	Y
Reliability Compliance (NERC) (contact: Erin McClatchey)	N
SOX Business Controls Impact Assessment (contact: Krista Johnson)	N
SOX Application Pre and Post Implementation Assessment (contact: Molly Favor)	N
Security Impact Assessment (SIA) (contact: Shanna Pagniano) - *Always Required*	Y
TSA Directive Review (contact: Jennifer Truman)	N
PCI (Payment Card Industry) Compliance Assessment (contact: Shanna Pagniano)	N
Network Impact Assessment (contact: Ignacio Chapa) - *Always Required*	Y

6.1 Compliance impact assessment statement and requirements

N/A

6.2 Business Continuity Plan/ Business Impact Assessment impact statement and requirements

A Business Continuity Plan/Business Impact Assessment will be conducted, and the results will be presented to the SteerCo for disposition.

6.3 Reliability Compliance impact statement and requirements

6.4 SOX Business Controls impact statement and requirements

6.5 SOX Application Pre and Post Implementation Assessment and requirements

N/A

6.6 Security Impact Assessment (SIA) and requirements

A Security Impact Assessment is needed to ensure implementation complies with Avista Cyber Security Policy in order to reduce risk to Avista. A preliminary SIA will be completed prior to execution and a final SIA will be approved by Security via Tracker prior to project closure. The final approval Tracker # will be included in the Approval to Close document.

6.7 PCI (Payment Card Industry) Compliance Assessment

N/A

6.8 Network Impact Assessment

A Network Impact Assessment will be completed by Network Engineering and submitted to the Steering Committee for approval.

6.9 Test strategy

A comprehensive test plan will be developed to ensure that all use cases, deliverables, and success criteria have been achieved.

Production Implementation Path and Rollback Plan

A comprehensive production implementation strategy will be developed to ensure the system is working as anticipated before placing the system into production. Any issues encountered during production implementation will be resolved by the engineers as they are encountered. Since this is a new system, no rollback is anticipated.

7 Budget & Resources

7.1 Labor Summary

Name	Role	Actual Hrs	Remaining ETC
Ben Benayad	Network Eng – Transport (Wireless RF)	339	566
Justin Boyer	Security Engineer - Cyber	62	139
Eric Frisbey	It Ops – Network Sys - Engineer	8	51
Dan Israel	Network Eng – Traffic Routing & Switching	222	110
Alek Makarov	Network Engineer – Transport (Wireless RF)	61	118
TBD	It Ops – Shop – Comm Tech	0	511
TBD	It Ops – Shop – Network Tech	0	264
Ade Ojomo	Network Eng – Transport (Wireless RF)	7	22
Shanna Pagniano	Product Owner	4	33
Gary Pellham	Project Manager	639	617
Tatiana Plett	Project Manager	601	0
Joe Richards	Network Eng – Traffic Routing & Switching	71	44
TBD	Security Engineer - Cyber	0	120
Paulo Tabino	Network Engineer – Transport (Wireless RF)	32	66
Andrey Tsyukalo	Project Coordinator	8	235
Courtney Wells	Project Coordinator	12	24
Elizabeth Arnold	Program Manager	7	24
Ignacio Chapa	Product Owner	7	27
Tatiana Plett	Product Owner	55	48
Bryan Rask	Network Engineer Manager	0	15
Jeff Holter	Program Manager	50	0
Emily Hunt	Scrum Master	23	43
Total of planned labor hours for Execution Phase			3,114

Project Management Plan

7.2 Financial Summary

Accounting summary for CPR modification. Note that the significant increase in "Estimate at Completion" is due to increased product costs, the decision to utilize professional services for implementation, migration of all deployed SAR Hmc's from the SCADA APN to the FirstNet APN, use of professional services to provide training for our operational support engineers and technicians, and the carrying costs associated with extending the project completion date due to the additional scope and lack of Avista resources available to work on the project.

Account Summary (Life-to-date plus forecast)	Project Financial Dashboard Description	Values
Report Date	**Actuals Through (mm/dd/yyyy):**	**9/30/2022**
Actual costs Project Life-to-date:	**Actuals –Capital Total** column	$656,612
Forecast for Execution and Closing[1]	**Forecast –Capital Total** column	$1,146,353
Estimate at Completion	**Project Total – Capital Total** column	**$1,802,965**
Project Budget	**Project Budget –Capital Total** column	$629,496
Variance		**($1,173,469)**

7.3 Operational Impact

Three Year Operational Impact	Org Code	Review and Approved	Year 1	Year 2	Year 3	Total
Licensing			$0	$0	$0	**$0**
Staff / Labor for O&M	J09 A09	Shawna Kiesbuy	$1,600	$1,600	$1,600	**$4,800**
Training			$0	$0	$0	**$0**
Product Maintenance	J09 A09	Shawna Kiesbuy	$24,828	$24,828	$24,828	**$74,484**
Telecom Services			$0	$0	$0	**$0**
Other Annual Operational Costs			$0	$0	$0	**$0**
Total			**$26,428**	**$26,428**	**$26,428**	**$79,284**

7.4 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories**. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service and removal and decommissioning of old assets.

Accounting Asset Category	Installation *(107600)*		Removal *(108000)*	Total ($)
	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Hardware (FERC Account 391)	$0	$0	$0	**$0**

[1] *Ensure that AFUDC has been calculated and included in the forecast for execution and closing.*

Communications Equipment (FERC Account 397)	$773,286	$1,029,679	$0	**$1,802,965**
Software (FERC Account 303)	$0	$0	$0	**$0**
Estimated Total Capital Cost:	**$773,286**	**$1,029,679**	**$0**	**$1,802,965**

8 Grade of Service

The Business Technology Grade of Service (GoS) is the integrated measurement of the success of Enterprise Technology to align with Avista's corporate strategy and contribute in achieving Avista's vision and strategic objectives.

The end of planning is defined for GoS purposes as the date this Project Management Plan (PMP) is approved. Once the PMP is approved a baseline is created. During the Closing phase the baseline is compared to actuals to measure how performance deviated from the baseline plan. Execution completion is defined as the date the Steering Committee approves the "Approval to Close" document, which should occur as soon as possible after final Execution tasks are complete.

8.1 Investment Performance to Budget

This GoS compares the *planned* total project cost as of the end of Planning plus approved Change Requests to the *actual* cost of the project at Closing. The amount listed below is the baseline. This should match the "Total at Completion" shown in the **Clarity Cost Plan**. The goal is for cost at completion to be within 90% to 100% of the planned cost. If Actual project cost exceeds approved project cost a CR must be submitted prior to closing.

Planned total cost at completion:	**$1,802,965.00**

8.2 Finish Performance to Schedule

This GoS compares the planned Execution completion date as of the end of planning to the actual Execution completion date. The date shown below should match the date shown in the Milestone table above and the date shown in Clarity for this milestone. The goal is +/- 1 month.

Planned date of Execution Complete:	04/23

8.3 Labor Performance to Estimate

This GoS compares planned labor hours as of the end of planning to actual labor hours at execution completion. The number below should match the total shown in the "Labor Summary" section of this document as well as the labor hours in Clarity for Execution tasks. The goal is +/-10%.

Planned labor hours during Execution:	**3,114**

8.4 Project Management Performance to Cost Standard

This GoS measures the percentage of total project cost that is attributable to Project Management efforts. The goal is for PM and PC costs to be 15% or less of total project cost. Calculate 15% of the "**Planned total cost at completion**" listed above and input the result below. The PM should manage PM and PC costs to this number. Remember to classify Business Analyst tasks using the "Input Type" of "Other" on your Clarity Timesheet. If you are not sure how to do this, please check with your program manager.

Planned PM labor cost:	**$180,296.50**

8.5 Change Order Performance

This GoS is based on the number of Change Requests submitted within 30 days of project closure. There is no baseline number for this measurement. When a PM is monitoring and controlling a project successfully, changes to scope, schedule, or budget should be known in a timely manner so change requests during the last 30 days of project should be uncommon. Please note that Change Requests within the last 30 days of closing only update the Capital Project Request (CPR), which is the total funded amount. They do not update baseline costs, dates, or labor hours for the purpose of Grade of Service.

8.6 Business Value Performance to Strategic Result Area

This GoS measures the success of the project in providing value to the company. Results are based upon a survey sent out to the steering committee and stakeholders. The survey should be sent as soon as possible after the steering committee approves project closure so that the project is fresh in the minds of the stakeholders.

9 Project Governance and Reporting

The purpose of these procedures is to provide effective mechanisms to control the scope of the project, manage issues and risks, and monitor progress.

9.1 Financial Control

Financial Control will be managed through **Clarity Cost Plan** and **Portfolio Management System**.
Note: Refer to the **Managing Cost Plans** in Clarity for specific instructions, located in **Monitor and Control** folder on the PMO SharePoint site.

9.2 Change Control

Change Control will be managed within the Clarity Project and Portfolio Management System. Below are the steering committee decisions regarding change control for this project:

9.2.1 Approval Authority

The project manager works closely with all stakeholders to ensure risk is mitigated and contingency plans are created and delivered. All stakeholders can identify a risk and offer a solution(s) for mitigation. Stakeholders can also recommend and develop contingency plans. Meetings are held to discuss risks, mitigation, and contingency recommendations. The project manager and product owner, work closely with the business partners, solution architects, developers and engineers on all risk identification, mitigation, and the development of contingency plans. Delivery of risk assessment and contingency planning is a responsibility of the project manager, with input from the delivery managers/business case owners. Based on the severity of the risk, the contingency plan can be approved by the product owner, project manager, or delivery manager/business case owner, with ultimate approval, if needed, from the steering committee. The solution architect, developers and engineers have the authority to implement plans and recommendations approved by the delivery managers/business case owners, product owner (if applicable), project manager and steering committee.

9.2.2 Specific types of risks, issues, and changes that must have steering committee approval before action can be taken.

Steering Committee members are invaluable to the project and will provide approval on scope, schedule, and budget related changes. Additionally, they will provide approval on issues and risks pertaining to project deliverables outlined in this document, which also typically have an impact on the scope, schedule, or budget of a project. Steering Committee members will also provide approval on Change Requests, Go-Live, and the Approval to Close document.

10 Roles and Responsibilities

10.1 Delivery Manager/ Business Case Owner, Steering Committee and Sponsor

The Delivery Manager/Business Case Owner will provide oversight and approval for all major elements of the Project. The Delivery Manager/Business Case Owner works closely with the Steering Committee and Project Manager in reviewing project plans, scope, budget, change requests and, when necessary, facilitates the resolution of issues to ensure successful completion of the initiative.

The Sponsor is responsible for:

- Championing the project and raise awareness at senior level
- Approving strategies, implementation plan, project scope and milestones
- Approving key organization/business decision for the project
- Resolving certain issues, policies, and change management
- Drive and manage change through the organization
- Ensuring that an appropriate project priority is established, and resources are allocated to the project
- Ensuring the timely and effective cooperation of all departments in providing information and other required assistance to the project teams
- Actively helping to remove obstacles and solve problems that are beyond the control of the Project Managers

10.2 Domain Architect

The Domain Architect will collaborate with technology teams, operational teams, project teams and other stakeholders to ensure the solutions provided by the project line up with internal architectural models showing the relationship between people, processes, information, and technology reflecting the company's strategies and goals.

The Domain Architect is responsible for:

- Performing domain architecture design and analysis work; providing appropriate related documentation, specifications, and presentations
- Collaborating with project and product teams to ensure consistency with enterprise architecture, as well as identifying when it is necessary to modify the enterprise architecture
- Communicating architectural designs, decisions, and recommendations back to the EAO
- Converting high level business requirements into system requirements
- Participating in Use Case development
- Establishing technology solutions
- Participating in technology vendor selections
- Participating in determining cost estimates
- Working with the Project Manager to communicate with business on project updates
- Helping educate the business on technology services, capabilities, and constraints

10.3 Primary Product Owner

Responsible for:

- Helps choreograph a Feature's User Stories that belong to multiple teams so that work occurs in the same or most optimal Sprint
- If Feature spans multiple teams, work with PPO
- If Story lives in a single team, work with PO

10.4 Chief Product Owner

Responsible for:

- Breaks "ties" on what work should be done when
- If needing to understand priority of one project compared to another, work with CPO

10.5 Project Manager

The primary responsibility of the Project Manager is the complete and satisfactory execution of the project. The project manager offers expertise in project management methodologies.

Responsible for:

- Project planning and execution
- Facilitate issue resolution
- Resolve scheduling issues
- Provide written plans and schedules templates
- Define, track, and maintain project schedule and budget
- Ensure project follows project management principles
- Manage communication between stakeholders
- Ensure project is delivered to schedule and budget (report on deviations)
- Manage project execution
- Coordinate resource requirements

10.6 Project Team

Responsible for:

- Support Project Manager
- Identify product or business requirements
- Ensure that the project requirements meet the needs and expectations of the project
- Ensure adherence to schedule commitments
- Reporting on progress/issues
- Execute project tasks

Audits may be performed at any time to validate that the standard process is being utilized.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Distribution System Reinforcements

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Our Distribution System Reinforcements business case is designed to give our Operations Engineers a mechanism that allows them to address system performance issues. Most of the work completed by this business case is meant to address system capacity issues. Other work includes addressing power quality mitigation, reliability improvements, operational flexibility, system protection improvements, safety reinforcements, and other performance issues. We submitted 4 CPG funds request throughout 2023 for this business case and received in total about $4.87 million in additional funds. These funds were needed to pay for projects that were unexpected and that needed to be completed as soon as possible. Most of the new projects were needed to resolve capacity issues, overloaded equipment, and voltage violations. In addition to the additional funds received from the CPG we also ended the year over budget by about 7%. This was mainly driven by higher than expected cost due to inflation, higher labor costs, and higher than expected contractor costs.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Additional spend (cost overruns) in this business case was monitored through the year and reviewed at the Electrical Engineering Budget Committee each month. As cost overruns (additional work scope in this case) were identified, a decision was made to request additional funds through the CPG process. Attached are the formal requests for additional funding.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The original offsets were calculated to be $957,777 (direct & indirect) but with the additional funds the new offsets are calculated to be $1,140,508 (direct & indirect). The new offsets were calculated using the actual spend/TTP for 2023.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: X

DIRECTOR SIGNATURE: X

Distribution System Enhancements

1.0 CHANGE REQUEST #1 – 01/17/2023

Previous Requests	Requested	Approved
5-Year Plan	$7,500,000	$7,000,000

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
01-2023	$100,398	$7,000,000	$750,000	$7,750,000

Type of Change	In-year Update
Primary Reason for Change	Scope Change
Response needed by	1/31/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

In 2022 our East Region Operations Engineer, Marshall Law, was approached by the new owners/managers of the Bunker Hill Mine and was asked about reestablishing significant load consumption for the mine. The mine under new ownership and management is requesting a total load capacity of 10.05 MVA with an aggressive timeline for bringing this load on in segments. The total load being requested will require a new substation transformer and a dedicated feeder for the mine which could not be accommodated given their aggressive timeline. However, Marshall was able to come up with a distribution feeder tie design that would allow us to shift about 2.4 MVA of load from our BUN426 feeder to BIG411 feeder. This in turn would free up enough capacity at the existing Bunker Hill substation to accommodate the mine's short-term needs, buying us time to complete the substation project.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

This work is needed now to accommodate our customer's request. If this request is not approved or deferred, we will not be able to meet our customer's timeline and they will have to delay their plans of reopening the mine. This has the potential of having a significant impact to the community in this area as the jobs that the mine's reopening will create will be delayed.

Distribution System Enhancements

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Please refer to Appendix A below which contains the Bunker Hill Sub Load Study.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

Successful implementation of this project will likely have to be done by a contract line crew. The Kellogg Operations Manager, Ben Little, has indicated that his crew will not be able to take on this project because of its size. The completion of this project will also likely have some level of O&M offsets as a large section of Kellogg's distribution line will be upgraded and thus require less maintenance.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

One alternative for funding of this project would be to require the customer to pay for the costs associated with constructing this new feeder tie, as the only reason the project is being pursued is to accommodate the re-opening timeline proposed by the mine. Previous to the current activities at the Bunker Hill mine, this project had not been identified as a need, and would not be pursued except to meet the mine's timeframe. Avista feels that the company should not require customer contributions to perform this work, as it will provide some limited benefit to Avista and the existing customers during and after the completion of the substation expansion work at Bunker Hill sub.

Another alternative considered was to absorb this cost into our existing budget. However, considering that the East Region has a $2 million budget this would consume almost half of their budget. This in turn will delay other planned and needed projects to reinforce their system to mitigate other issues. These issues include capacity issues, voltage issues, VAR support, wildfire mitigation, reliability issues, overload issues, relay protection issues, and safety issues. In addition, some of these projects are also tied to other customer requests and are needed to make good on previous commitments. The East Region's budget is fully subscribed for the foreseeable future with planned work to stay ahead of load growth causing feeder capacity constraints. Below is a list of the projects planned for 2023.

WAL543 - CRAPO Replacement $200k

- Multiyear project budgeted through wildfire and this business case
- Wildfire mitigation, reliability issues, overload issues, protection issues

WAL542 - Lookout Pass Upgrades (multi-year) $150k

- Project is tied to another customer request
- Capacity issues

OGA611 - Extend trunk toward Carlin Bay (multi-year) $350k

Distribution System Enhancements

- Project tied to Carlin Bay substation project which is needed for a multitude of system issues in the area.

STM632 - Smart Cap Bank	$75k
• VAR support	
PRV752-Reroute Settlement Road (multi-year)	$50k
• Reliability and accessibility issues	
SPT4S21 / SPT4S23 - Future Bronx Reinforcement	$300k
• Project tied to a future Bronx substation project that will help with capacity issues and give us the ability to offload the Sandpoint substation so that it can be rebuilt	
IDR253-Tie to PVW241 at Beck Rd (mult-year)	$200k
• Capacity issues	
RAT233/AVD151 - New Feeder Tie (multi-year)	$250k
• Capacity issues	
HUE141 to HUE142 Tie - Meyer Road	$125k
• Capacity issues	
BLU321 - Add 3rd ph Wolflodge lat	$150k
• Capacity and voltage issues	
BLU321 - Blue Creek Rd UG Conversion	$150k
• Reliability and safety issues	
Total:	$2,000k

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

Considering our obligation to serve and that this project is the only feasible way for us to meet this customer's timeline this project is still prudent for the company to complete. Additionally, the mine reopening will provide many jobs to the local community thus providing additional benefits to our customers.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid given the nature of this change.

Distribution System Enhancements

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Cesar Godinez	BC Owner		1/17/2022
Vern Malensky	BC Sponsor	Vern Malensky	1/18/2022
	FP&A		

APPENDIX A

Bunker Hill Load Study

Last Updated: 6/10/2022 by mjl

Project Overview

New owners of the Bunker Hill Mine are looking at starting the mine back up into full operation. As part of this overall project, they will need to significantly increase the electric usage at the Bunker Hill mine site that is located near Bunker Hill Sub. This document details the analysis to determine how much load can be added at the Bunker Hill mine site with minimal work required, i.e. utilizing existing system capacity.

Input Data Source

Bunker Hill Substation does not have SCADA so monthly demand reads from inspection data was used for the study. In order to estimate the coincident transformer load, a 95% diversity factor was applied to the summation of the individual feeders. The 95% factor was developed by considering the summer and winter peak loading at Pine Creek Substation (which does have SCADA) and comparing the transformer loads against the summed feeder loads. Using this methodology, the calculated diversity factor for Pine Creek was 93% (329 A-ave / 354 A-ave) in the summer and 97% (362 A-ave / 374 A-ave) in the winter, with 95% being the average of those two values. Using a 95% diversity factor for Bunker Hill should be a conservative approach given there are four feeders at Bunker Hill (as compared to three feeders at Pine Creek), so in theory there should be at least as much (if not more) diversity at Bunker Hill using this approach.

Performance Criteria / Loading Limitations

The maximum allowable demand for both transformer and feeder loading was considered to be 80% of the corresponding transformer or feeder SVL rating. The 0 deg SVL was the assumed winter value, and the 40 deg C SVL was the assumed summer value. The 80% of SVL limitation is consistent with the latest version of Avista's Planning Criteria document.

Distribution System Enhancements

Bunker Hill Sub – Existing Load Levels

BUN422 (Smelterville Feeder) – Existing Loading Levels

- Summer → 111 / 114 / 110 A (July 2020 Loads) →111.7 A (ave) →2.55 MVA
- Winter → 99 / 102 / 101 A (February 2022 Loads) →100.7 A (ave) →2.30 MVA

This feeder contains the Zanetti Rock Crusher, as well as the existing Bunker Hill Mine loads. The monthly demand reads from CC&B are shown below as additional information, but they were not used directly in the analysis.

Zanetti Rock Crusher – Existing Demand

FILTERS: SERVICE AGREEMENT 7047686322 , UNIT OF MEASURE KW

	YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	2022			768.0	504.0								

Badge Number	Start Date	End Date	Read Type	Days of Svc	UOM	Usage Amount	Demand	KVAR Quantity
C12212856	5/17/20	6/16/20	Regular Read	30	KWH	55,500	720	612
C12212856	6/16/20	7/18/20	Regular Read	32	KWH	42,900	687	615
C12212856	7/18/20	8/16/20	Regular Read	29	KWH	0	0	0
C12212856	8/16/20	9/16/20	Regular Read	31	KWH	31,200	603	588
C12212856	9/16/20	10/17/20	Regular Read	31	KWH	1,500	546	414

Historic Peak Demand is approximately 768 kW / 76% pf = 1.01 MVA

Bunker Hill Mine – Existing Demand

FILTERS: SERVICE AGREEMENT 8468064604 , UNIT OF MEASURE KW

	YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	2022	304 +	192.0	184.0	184.0								

FILTERS: SERVICE AGREEMENT 8468064604 , UNIT OF MEASURE KVAR

	YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	2022	192 +	120.0	112.0	120.0								

Service Type	SA Account ID	Service Agreement	Badge Number	Start Date	End Date	Read Type	Days of Svc	UOM	Usage Amount	Demand	KVAR Quantity
E	1202252117	1207236727	C12159913	11/10/21	12/13/21	Regular Read	33	KWH	89,600	192	120
	1202252117	1207236727	C12159913	12/13/21	1/7/22	Regular Read	25	KWH	99,200	192	112
	8462191371	8468064604	C12159913	1/7/22	1/14/22	Regular Read	7	KWH	13,600	112	72
	8462191371	8468064604	C12159913	1/14/22	2/14/22	Regular Read	31	KWH	117,600	192	120
	8462191371	8468064604	C12159913	2/14/22	3/15/22	Regular Read	29	KWH	122,400	192	120
	8462191371	8468064604	C12159913	3/15/22	4/13/22	Regular Read	29	KWH	116,800	184	112
	8462191371	8468064604	C12159913	4/13/22	5/12/22	Regular Read	29	KWH	116,000	184	120

Distribution System Enhancements

Historic peak demand is approximately 192 kW + 120 kVAR = 226 kVA

BUN423 (Kellogg West Feeder) – Existing Loading Levels

- Summer → 176 / 183 / 245 A (July 2021 Loads) → 201.3 A (ave) →4.60 MVA
- Winter → 171 / 191 / 241 A (February 2022 Loads) → 201.0 A (ave) → 4.60 MVA

BUN424 (Silver Mountain Feeder) – Existing Loading Levels

- Summer → 42 / 48 / 55 A (August 2021 Loads) → 48.3 A (AVE) →1.10 MVA
- Winter → 73 / 76 / 77 A (January 2022 Loads) → 75.3 A (AVE) → 1.72 MVA

BUN426 (Kellogg East Feeder) – Existing Loading Levels

- Summer → 61 / 60 / 84 A (August 2021 Loads) → 68.3 A (AVE) →1.56 MVA
- Winter → 85 / 70 / 102 A (February 2022 Loads) → 85.7 A (AVE) → 1.96 MVA

Existing Load Summary

Feeder	**Peak Summer Loads**		**Peak Winter Loads**	
	Average Amps	MVA	Average Amps	MVA
BUN422	112 A	2.6	101 A	2.3
BUN423	201 A	4.6	201 A	4.6
BUN424	48 A	1.1	75 A	1.7
BUN426	68 A	1.6	86 A	2.0
Total Summed Load	429 A	9.9	463 A	10.6
Diversified Load (Assume 95% Factor)	408 A	9.3	440 A	10.1
Transformer SVL	683 A	15.6	837 A	19.1
Existing % of SVL	60%		53%	

Known Planned Load Additions

BUN424 (Silver Mountain Feeder)

Distribution System Enhancements

- Silver Mountain Chair Upgrades
  - 1000 kVA (44 A) → winter only
  - Anticipated go-live with new load in winter 2023
- Future Load (with addition)
  - Summer → 48 A →1.1 MVA
  - Winter → 75 A + 40 A = 115 A → 2.6 MVA

BUN426 (Kellogg East Feeder)

- Bunker Hill Mine Wardner Expansion (i.e. Blue Bird Mine)
  - 1850 kVA (80 A) → year-round
  - Anticipated go-live with new load in 2023
- Future Load (with addition)
  - Summer → 68 A + 80 A = 148 A → 3.4 MVA
  - Winter → 86 A + 80 A → 166 A → 3.8 MVA

Future Load Summary (with Known Planned Load Additions)

Feeder	**Peak Summer Loads**		**Peak Winter Loads**	
	Average Amps	MVA	Average Amps	MVA
BUN422	112 A	2.6	101 A	2.3
BUN423	201 A	4.6	201 A	4.6
BUN424	48 A	1.1	**115 A**	2.6
BUN426	**148 A**	3.4	**166 A**	3.8
Total Summed Load	509 A	11.7	583 A	13.3
Diversified Load (Assume 95% Factor)	484 A	11.1	554 A	12.7
Transformer SVL	683 A	15.6	837 A	19.1
Future % of SVL	71%		66%	

Distribution System Enhancements

Base Analysis of Available Capacity for Bunker Hill Mine

	Peak Summer Loads		Peak Winter Loads	
	Average Amps	MVA	Average Amps	MVA
Transformer				
Projected Peak Demand Loads	484 A	11.1	554 A	12.7
Transformer SVL	683 A	15.6	837 A	19.1
80% of XFMR SVL	546 A	12.5	670 A	15.3
Available Transformer Capacity	**(546 – 484) A = 62 A**	**1.4**	(670 – 554) A = 116 A	2.7
BUN422 Feeder				
Projected Peak Demand Load	112 A	2.6	101 A	2.3
Feeder SVL	324 A	7.4	481 A	11.0
80% of Feeder SVL	259 A	5.9	385 A	8.8
Available Feeder Capacity	147 A	3.4	284 A	6.5

Considering summer load conditions for a worse case analysis, we have approximately 1.4 MVA of uncommitted available capacity in the summer at Bunker Hill Sub (i.e. transformer capacity). The existing BUN422 feeder has available capacity of about 3.4 MVA, so the transformer summer loading scenario is the limiting factor on capacity that is available. If some load from BUN422 can be permanently transferred to the adjacent feeder PIN442, then it may be possible to realize more than a 1.4 MVA load addition.

<u>Analysis of Available Capacity for Pine Creek Sub / Page Feeder</u>

With that in mind, I will next consider loading levels at Pine Creek to determine the feasibility of transferring some amount of load from BUN422 to PIN442.

<u>PIN441 (Pine Creek Feeder) – Existing Loading Levels</u>

- Summer → 108 / 116 / 110 A (6/30/21 Loads) → 111.3 A (ave)
- Winter → 139 / 111 / 127 A (2/23/22 Loads) → 125.7 A (ave)

<u>PIN442 (Page Feeder) – Existing Loading Levels</u>

- Summer → 93 / 84 / 82 A (6/28/21 Loads) → 86.3 A (ave)
- Winter → 105 / 81 / 86 A (2/22/22 Loads) → 90.7 A (ave)

<u>PIN443 (Mission Feeder) – Existing Loading Levels</u>

- Summer → 181 / 108 / 157 A (7/31/21 Loads) → 148.7 A (ave)
- Winter → 190 / 124 / 157 A (2/23/22 Loads) → 157.0 A (ave)

	Peak Summer Loads		**Peak Winter Loads**	
	Average Amps	MVA	Average Amps	MVA
<u>Transformer</u>				
PIN441	111 A		126 A	
PIN442	86 A		91 A	
PIN443	157 A		157 A	
Total Summed Load	354 A		374 A	
Diversified Load (Assume 95% Factor)	336 A		355 A	
Transformer SVL	956 A		960 A	

Distribution System Enhancements

80% of XFMR SVL	765 A		768 A	
Available Transformer Capacity	429 A	9.8	413 A	9.4
PIN422 Feeder				
Projected Peak Demand Load	86 A		91 A	
Feeder SVL	234 A		342 A	
80% of Feeder SVL	187 A		274 A	
Available Feeder Capacity	101 A	2.3	183 A	4.2

The summary of this analysis shows that we could add approximately 2.3 MVA of load to the PIN442 feeder before experiencing loading feeder loading issues. The transformer itself has plenty of capacity to support increased feeder load on PIN442.

The most feasible load transfer from an electrical perspective would be to close Switch# C403 and open Switch# C402. This would transfer approximately 73 A per phase (1.7 MVA) from BUN442 to PIN422 (summer peak loading).

Original Loading Levels (Summer Peak)

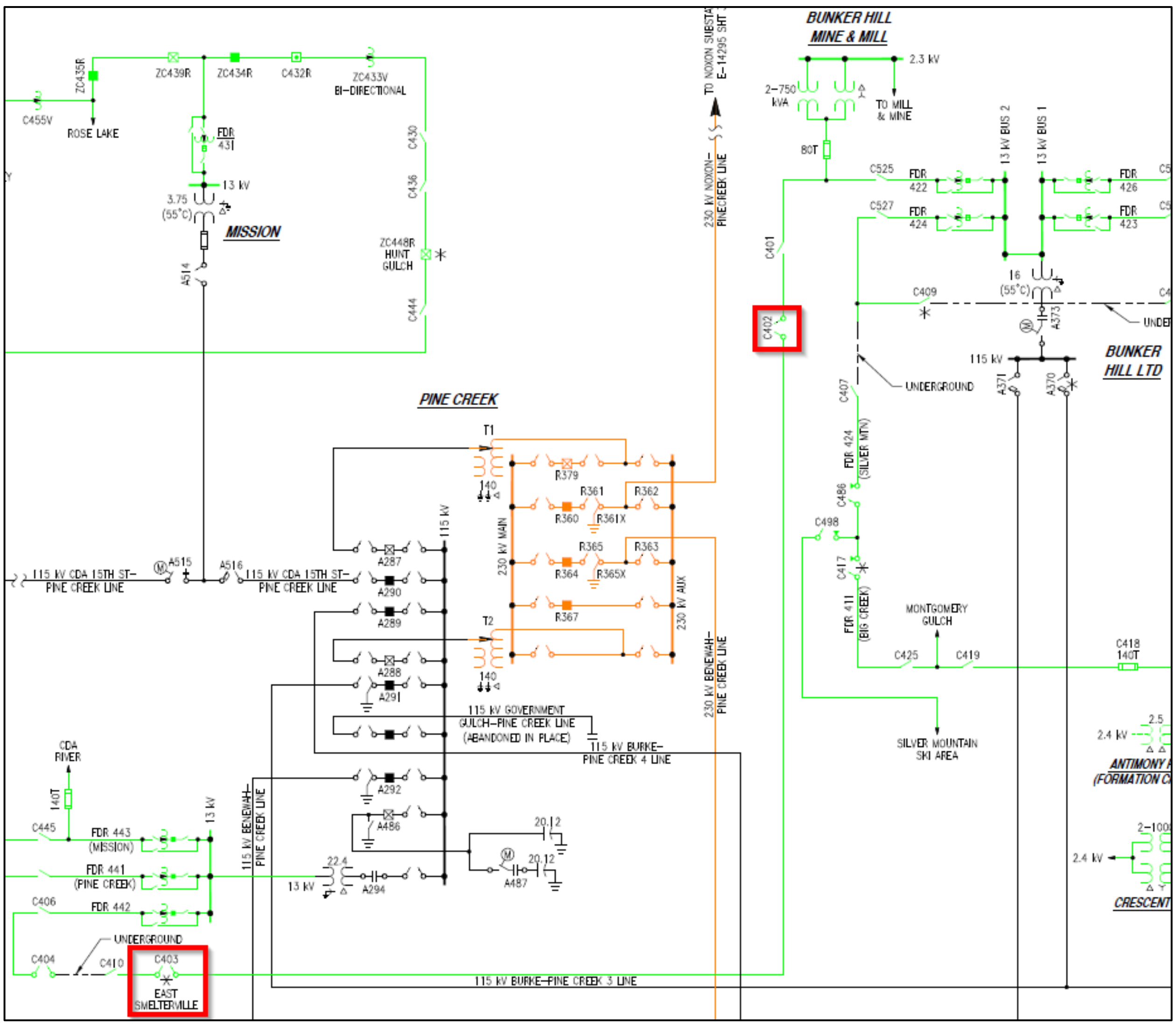
Source Id	Amps A	B	C	Avg
Feeders for Bunker Hill Limited 115/13 kV				
BUN422	112	115	111	112
Feeders for Pine Creek 230/115 kV				
PIN442	94	85	83	87

Loading Levels after load cut between BUN422 & PIN443

Distribution System Enhancements

Source Id	Amps A	B	C	Avg
Feeders for Bunker Hill Limited 115/13 kV				
BUN422	39	44	40	41
Feeders for Pine Creek 230/115 kV				
PIN442	168	157	155	160

Note that the existing protection settings for PIN442 will only coordinate with a 100T fuse. Breaker protection setting modifications will be required to allow for coordination with a 140T fuse if this load cut is pursued.



Distribution System Enhancements

Modified System Analysis of Available Capacity for Bunker Hill Sub

- Incorporates the shifting of 1.7 MVA of load from BUN422 to PIN442

	Peak Summer Loads		Peak Winter Loads	
	Average Amps	MVA	Average Amps	MVA
Transformer				
BUN422	41 A		37 A	
BUN423	201 A		201 A	
BUN424	48 A		115 A	
BUN426	148 A		166 A	
Total Summed Load	438 A		519	
Diversified Load (Assume 95% Factor)	416 A		493 A	
Transformer SVL	683 A		837 A	
80% of XFMR SVL	546 A		670 A	
Available Transformer Capacity	**130 A**	**3.0**	177 A	4.0
BUN422 Feeder				
Existing Load (after transfer to PIN442)	41 A		37 A	

Distribution System Enhancements

Available Transformer Capacity (Load Add)	130 A		177 A	
New Projected Feeder Load	171 A	3.9	214 A	4.9
Feeder SVL	324 A		481 A	
Anticipated % SVL Loading (New Loads)	52%		44%	

The BUN422 feeder can accommodate the addition of 3.0 MVA without causing any feeder loading issues. This addition will load the Bunker Hill Substation to 80% of its summer capacity.

Distribution System Enhancements

1.0 CHANGE REQUEST #2 – 01/17/2023

Previous Requests	Requested	Approved
5-Year Plan	$7,500,000	$7,000,000
#1 – 01/17/2023	$750,000	

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
01-2023	$100,398	$7,000,000	$675,000	$7,675,000 ($8,425,000 if #1 approved)

Type of Change	In-year Update
Primary Reason for Change	Scope Change
Response needed by	1/31/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

In 2022 our Spokane Operations team was approached by an existing customer, Jubilant HollisterStier (JHS), about their plan to add significant load to our Spokane electric distribution system over the next two years. These load additions are planned in two phases the first planned for March of 2023 (3.1 MVA) and the second planned for June of 2024 (3.7 MVA). The second load addition for JHS is utilizing a federal grant that requires they show significant completion/operation to qualify for the grant. JHS is currently fed from our BEA12F5 feeder which reached a peak SCADA Variable Limit (SVL) of 92% (471 amps) during the heat event of June 2021. There is not enough capacity on our distribution system in this area to accommodate the new load proposed by JHS. To accommodate these load requests our Spokane Operations Engineers have developed a plan to perform several load transfers, build a new Lyons and Standards feeder, and upsize the feeder regulators on our BEA12F5 feeder.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

This work is needed now to accommodate our customer's request. If this request is not approved or deferred, we will not be able to meet our customer's timeline and they will have to delay their operation plans. This in turn can have an adverse effect on their ability to qualify for the federal grant they plan to use to help fund their second load addition.

Distribution System Enhancements

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Please refer to Appendix A below which shows the project specifics and initial load study for the proposed load addition by JHS.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

The business functions that are impacted by this business case and this project specifically are Spokane Operations, Distribution Engineering, Substation Engineering, Distribution Operations, and GPSS. To successfully implement this work, we'll need to work with Spokane Operations to identify who will complete the line work and we need to ensure that Distribution Operations is aware and onboard with making the load transfers. In addition, this work will require the creation of a new feeder at the Lyons and Standard substation which drives work within the GPSS group.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

One alternative considered was to create a dedicated feeder for JHS as their existing load and proposed load additions would warrant such an approach. This dedicated feeder would come from a new feeder position at our Lyons and Standards substation, and it would require us to rebuild an existing 3.5-mile line section to a double circuit line. A good portion of this work would also require a Transmission line rebuild, some of this line section is underbuilt on a Transmission line. This alternative was not picked because of the additional customer impacts and the higher cost. The current estimate to complete the work under this option is $2.2 million minimum and it would likely exceed this value.

Another alternative considered was to absorb this cost into our existing budget. However, considering that the Spokane/Deer Park Region has a $2.75 million budget this would consume about a quarter of their budget. This in turn will delay other planned and needed projects to reinforce their system to mitigate other issues. These issues include capacity issues, voltage issues, power quality issues, reliability issues, easement issues, clearance issues, and safety issues. In addition, some of these projects are also tied to other customer requests and are needed to make good on previous commitments. The Spokane/Deer Park Region's budget is fully subscribed for the foreseeable future with planned work to stay ahead of load growth causing feeder capacity constraints. Below is a list of the projects planned for 2023.

COB12F1-to-MEA12F2/WAK12F1 Wandermere Tie – Part 1 $100k

- Multiyear project is tied to another customer request (GEM apartments)
- Capacity issues

9CE12F1 EV Charger at Fred Meyers Tie $342k

- Capacity issues

Distribution System Enhancements

9CE12F1 / 9CE12F5 Carnahan West Dev Recond	$350k

- Capacity and reliability issues

BEA12F2 Sekani Development Reconductor — $240k

- Capacity issues

AIR12F1 Hwy2 East Recond — $392k

- Capacity issues

LOO12F1 - Hwy395&State to south 1 mile — $400k

- Multiyear project, last part to finish this feeder tie work
- Capacity and reliability issues

DEP12F1 Fir Ave Recond to 2/0ACSR — $267k

- Capacity and reliability issues

BEA12F1 - Felts Field — $242k

- Capacity issues

SIP Upgrades - Part 1 of 6 — $400k

- Multiyear project starting this year
- Reliability issues, clearance issues, safety issues

Henry Rd Overpass — $???k

- Project is a carryover from 2022
- Capacity issues

PST12F1/12F2 Riverfront Park NORTH/SOUTH Pedestrian Bridge Renovation — $100k

- Customer requested project (City of Spokane)

Total: $2,833k

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

Considering our obligation to serve and that this project is the least expensive option we've been able to develop to meet the customer's timeline this project is still prudent for the company to complete. An unknow is how these load additions from JHS will impact their staffing levels and this project could be helping to provide more jobs for our customers.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid given the nature of this change.

Distribution System Enhancements

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Cesar Godinez	BC Owner		1/17/2022
Vern Malensky	BC Sponsor	Vern Malensky	1/18/2022
	FP&A		

Distribution System Enhancements

APPENDIX A

Jubilant HollisterStier

(Henceforth "JHS")

"Customer Load Addition and Implementation of Subsequent System Upgrades and Reconfigurations Necessary to Serve Said Load, REV0"

{AKA "Robbing Peter to Pay Paul"}

Preliminary Modeling, Engineering Analysis, Cost Estimate, and Narrative completed by Jon Gilrein, PE on 7/22/2022

Distribution System Enhancements

PROJECT NARRATIVE

Jubilant HollisterStied (JHS) is planning to add significant load to our Spokane Distribution System over the next two years. The additions will take place in two phases, the first is planned for March of 2023, and the second is planned for June of 2024. The blocks of load being added are expected to be 3.1MVA and 3.7MVA, respectively. The second load addition planned for June of 2024 is utilizing a federal grant, and is considered a *critical path project* by the customer, as significant completion/operation must be shown by June of 2024 to qualify for the grant. The existing feeder serving the JHS load is BEA12F5, which reached a peak SVL utilization of 92% (471A) during the heat event of June 2021. There is not enough capacity using the existing distribution system to support the new proposed load from JHS.

At least two viable options exist for serving the additional 6.8MVA connected/5.5MVA calculated load from JHS (for an explanation regarding connected vs calculated load, please see the *Modeling and Engineering Analysis* section of this report). The first option is to build out a dedicated feeder fed a new breaker position at Lyons and Standard Substation. This option would require and upgrade of approximately 3.5 miles of existing distribution alignment to double distribution alignments; additionally, there is at least one alignment that would require a significant Transmission rebuild (approx. ½ mile) to accommodate Dx underbuild. While the load from JHS is large enough to justify a dedicated circuit to serve the facility, it is not preferable due to the potential for negative customer impact, difficulties with constructability, and the significant cost impact. The current estimate for upgrading the system to accommodate the 3.5 miles of double distribution is *at a minimum* $2.2M, and would likely exceed that value.

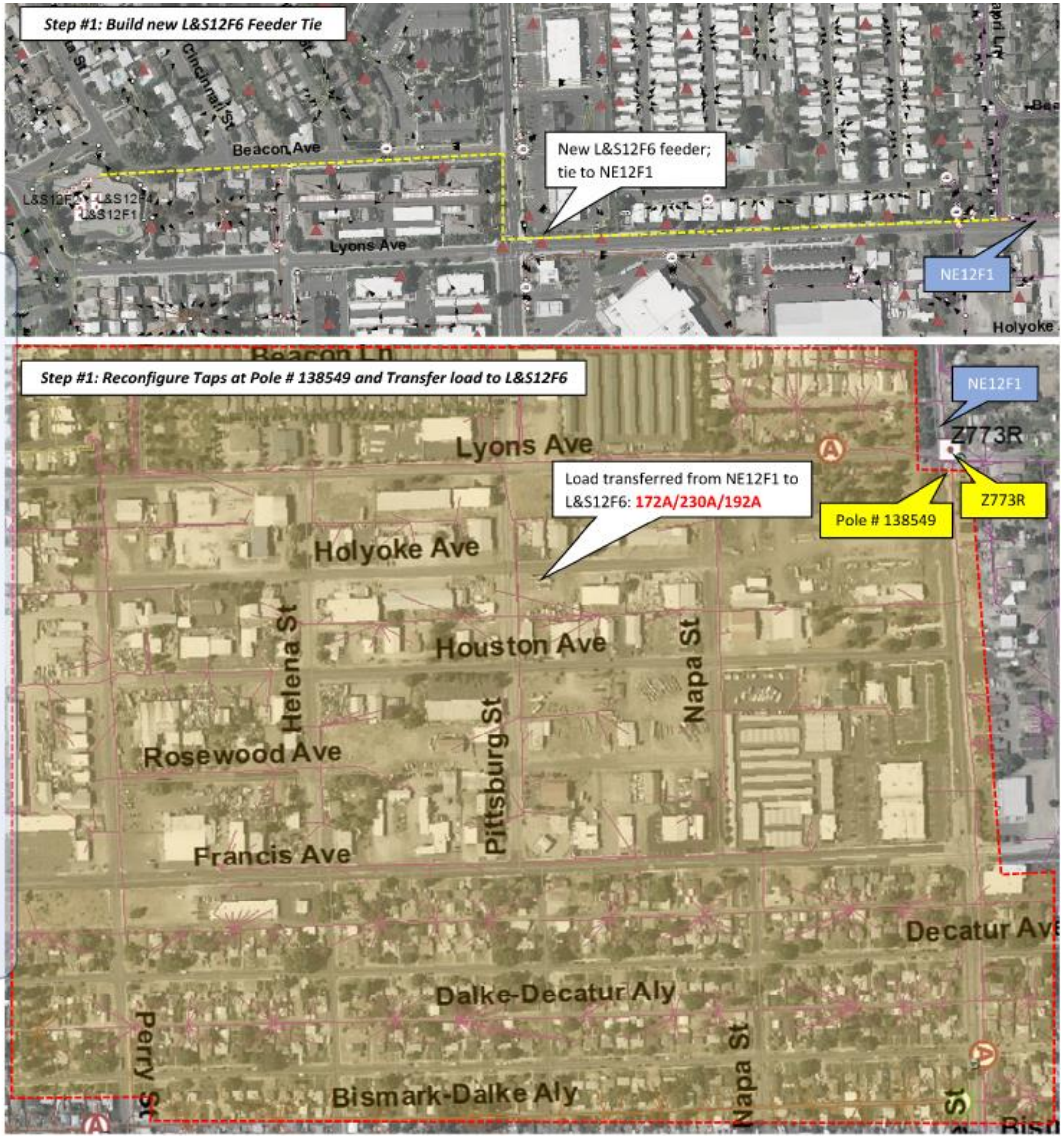
The second option requires several load transfers (three levels) between two Northeast Substation feeders, one Beacon Substation feeder, a new Lyons and Standard Substation feeder, and replacement of existing 250kVA feeder regulators with 333kVA regulators on BEA12F5. The following narrative provides the details regarding this design approach.

DETAILS OF PROPOSED SYSTEM UPGRADES AND RECONFIGURATIONS

Step #1: Build out and integrate new feeder from L&S Sub, L&S12F6. Approximately 2,900' of 556AAC trunk will need to be extended from the L&S Sub east to Capri Ln & Lyons Ave, where it will tie into NE12F1. Next, the corner structure at the intersection of Lyon's Ave and Crestline St will be reframed such that the western and southern taps downstream of Recloser Z773R at Pole # 138549 are physically disconnected from NE12F1, and fed from the new L&S12F6 feeder to the east.

Step #2: Build section of double circuit from Capri Ln & Lyons Ave to Francis Ave & Regal St. Approximately 3,400' of existing single circuit line will need to be upgraded to double circuit with 556AAC as the top ("express") circuit conductor, with NE12F1 being extended via the top position from west of Recloser Z772R to the intersection of Francis Ave & Regal St. Existing east-to-west load currently served by NE12F4 will be transferred to NE12F1 by reconfiguring the taps at Pole # 165920.

***Step #3** (not shown)*: Replace existing BEA12F5 250kVA station regulators with 333kVA units. Regulator replacement will increase the 40C SVL (which is the limiting factor) from a rating of 512A to a rating of 600A, a capacity increase of just over 2MVA.



Distribution System Enhancements

Step #4: Move the normal open point between BEA12F5 and NE12F4. Switch Z21 is the existing normal open point between the feeders; this device will be closed, and the new normal open point will be Recloser Z337R. Loads north of the JHS facility will be served by NE12F4, providing the capacity needed on BEA12F5 to support the total JHS load (existing + new).

Summary of System Upgrades and Reconfigurations and Approximate Costs:

- Build and Integrate new L&S12F6 Feeder, offloading NE12F1 to new feeder: $350k
- Upgrade section to double distribution circuit, offloading NE12F4 onto NE12F1: $325k
- Replace BEA12F5 regulators with 333kVA units, increasing feeder SVL: $100k
- Change N.O. between BEA12F5 and NE12F4, offloading BEA12F5 to NE12F4: $0
    - *TOTAL ESTIMATED COST FOR SYSTEM UPGRADES & RECONFIG: **$775k***

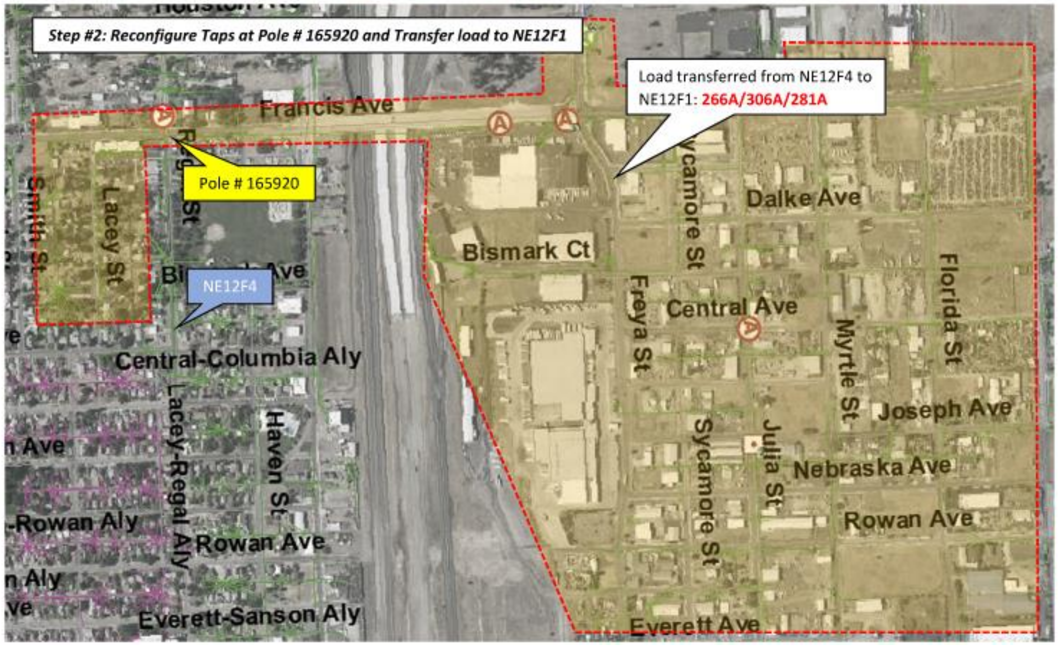
<u>MODELING AND ENGINEERING ANALYSIS OF PROPOSED SYSTEM UPGRADES AND RECONFIGURATIONS</u>

Loading for the Synergi analysis model was taken from 2022 summer peak (to date) for feeders BEA12F5 (7/12/22; 69% of 40C SVL), NE12F1 (7/20/22; 59% of 40C SVL), and NE12F4 (7/12/22; 68% of 40C SVL). The values from PI are as follows: BEA12F5 load is 301A/275A/300A; NE12F1 load is 236A/297A/260A; and NE12F4 load is 374A/384A/404A.

JHS current peak load is 3.6 MVA (158A per phase), and the phased additions as provided by the customer are 3.1MVA (3/2023, 136A per phase) and 3.7MVA (6/2024, 162A per phase). The values provided by the customer reflect "connected kVA", so a *conservative* demand factor of .8 will be used for analysis purposes. With the 80% demand factor applied, customer loads become 2.9MVA/127A per phase (current), 2.5MVA/110A per phase (3/2023), and 3MVA/132A per phase (6/2024).

Initial load allocation to the Synergi model produces the following feeder amps. Again, this reflects the current 2022 summer peak, as the 2021 summer peak should be considered an "outlier". Due to a setting in Synergi, allocated loads don't *exactly* represent use input (i.e. 1A difference); I don't know what this setting is or why it does this. *<u>It is highly recommended that this same analysis be performed after summer of 2022, to ensure that the true summer peaks for each feeder of summer 2022 is captured.</u>*

Source Id	Amps A	Amps B	Amps C	Amps Avg	Amps N	Loading % Rat	Loading % Imb
Feeders for Beacon 230/115 kV							
BEA12F5	300	274	299	291	25	58.60	5.81
Feeders for Northeast 115 kV							
NE12F1	235	296	259	264	53	57.83	12.36
NE12F4	373	383	403	386	27	67.08	4.39



Distribution System Enhancements

After execution of **Step #1**, the model provides the following feeder amps.

Source Id	Amps A	Amps B	Amps C	Amps Avg	Amps N	Loading % Rat	Loading % Imb
Feeders for Beacon 230/115 kV							
BEA12F5	300	274	299	291	25	58.60	5.81
Feeders for Northeast 115 kV							
NE12F1	67	69	70	69	2	13.71	2.62
NE12F4	373	383	403	386	27	67.08	4.35

L&S12F6	172	230	192

After execution of **Step #2**, the model provides the following feeder amps.

Source Id	Amps A	Amps B	Amps C	Amps Avg	Amps N	Loading % Rat	Loading % Imb
Feeders for Beacon 230/115 kV							
BEA12F5	300	274	299	291	25	58.60	5.81
Feeders for Northeast 115 kV							
NE12F1	331	376	349	352	42	73.47	6.83
NE12F4	107	75	119	100	37	19.81	25.05

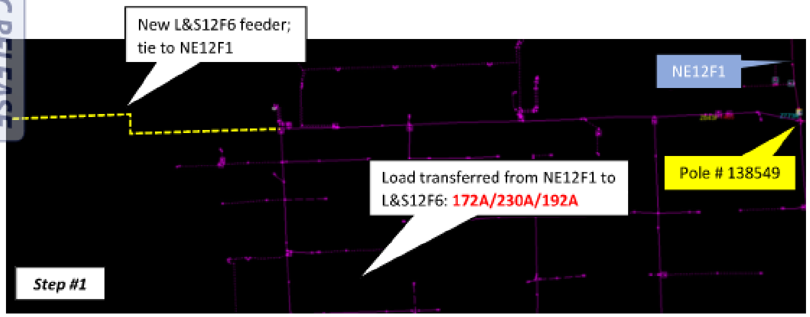
L&S12F6	172	230	192

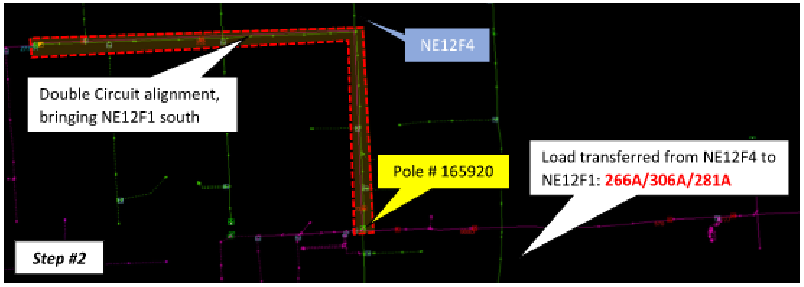
Execution of **Step #3** increases the SVL of BEA12F5, and is not shown due to no load transfers occurring.

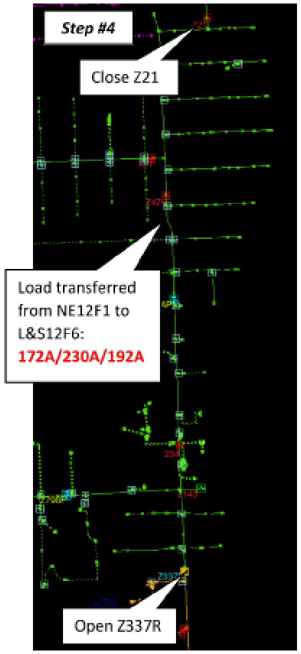
After execution of **Step #4**, the model provides the following feeder amps.

Source Id	Amps A	Amps B	Amps C	Amps Avg	Amps N	Loading % Rat	Loading % Imb
Feeders for Beacon 230/115 kV							
BEA12F5	136	148	138	141	12	28.93	5.13
Feeders for Northeast 115 kV							
NE12F1	331	376	349	352	42	73.47	6.83
NE12F4	273	207	284	255	71	47.18	18.52

L&S12F6	172	230	192







Distribution System Enhancements

After JHS load additions (phase #1 and phase #2), the model provides the following feeder amps.

Source Id	Amps A	B	C	Avg	N	Loading % Rat	% Imb
Feeders for Beacon 230/115 kV							
BEA12F5	366	377	368	370	12	73.55	1.77
Feeders for Northeast 115 kV							
NE12F1	331	376	349	352	42	73.47	6.83
NE12F4	273	207	284	255	71	47.18	18.52

L&S12F6	172	230	192

SUMMARY OF MODELING, ENGINEERING ANALYSIS, AND RECOMMENDATION

Based on the most current information regarding the system available, and the supplied customer load addition information, the described approach is recommended. There are several significant benefits to performing the upgrades and reconfigurations shown above, including reduced cost, the ability to continue serving the customer from the existing feeder, improvement of system loading, utilization of a new feeder to support growing load, reduction in timeframe to construct facilities to meet customer schedule, and reduced impact to customers. Thank you for your time and consideration.

Distribution System Enhancements

1.0 CHANGE REQUEST #3 – 03/14/2023

Previous Requests	Requested	Approved
5-Year Plan	$7,500,000	$7,000,000

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
03-2023	$955,228	$7,750,000	$1,070,000	$8,820,000

Type of Change	In-year Update
Primary Reason for Change	Scope Change
Response needed by	4/5/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

On and around December 22, 2022, our service territory experienced a cold snap that stressed our distribution system past its limits in various locations which resulted in having overloaded equipment and low voltage issues. Most of these system constraints were not previously known to us and the others were being planned for, but the cold snap accelerated their need by date. Our Operations Engineers in the East Region and Colville had to actively deal with system constraints during the cold snap and afterwards they conducted system analysis that revealed the extent of the system constraints. Additionally, one of the low voltage issues in the Colville area (Orient) is tied to two Commission complaints.

Here is a breakdown of the needs identified in the East Region:

- BLU321 – Eliminate SOLID Door cutouts on up/down poles at 4 locations
    - Total cost estimate for all locations is **$70k**
- BLU321 – Replace 3ph 150A C952V regulator bank at Neachen Bay with 328A smart regs
    - Cost estimate **$100k**
- OGA611 – Replace 3ph 150A C620V regulator bank in Harrison with 219A smart regs
    - Cost estimate **$90k**

Here is a breakdown of the needs identified in Colville:

- ORI12F3 – Add a 2nd Phase in two locations
    - Total cost estimate for both locations is **$220k**

- CLV12F4 – Add a 2nd Phase in one location
  - Cost estimate **$65k**
- KET12F2 – Reconductor 1.8 miles of OH and add a 2nd stage midline voltage regulator
  - Cost estimate **$280k**
- ORI12F1 – Add a 1 phase voltage regulator and create new feeds
  - Total cost estimate for all locations is **$125k**
- CLV34F1 – Add 3 phase voltage regulator and create new URD lateral tie/feeds
  - Cost estimate **$120k**

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

The need for this work now is driven by our need to correct system issues/constraints that have been identified that were previously not on our immediate radar. The risk of not approving or deferring this request would come in form of having to push out our other needed work or possibly looking at funding this work through the Minor Rebuild business case. Not addressing the overloaded equipment and low voltage issues would add significant risk to the company and we could be fund negligent if these items caused other issues. In addition, we have two Commission complaints tied to one of the low voltage issues in Colville and it is not advisable to do nothing to address them.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Please refer to Appendix A below which contains additional information about the projects and analysis work that has been completed.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

The main business functions that will be impacted are Colville Operations, East Region Operations, Customer Service, and Distribution Engineering. Our Operations Engineers will need to work closely with all these groups to ensure that this work is successfully implemented. The completion of this work would also have some O&M offsets as we replace and/or install new equipment to mitigate the issues. Additionally, there will likely be O&M offsets as we resolve the Commission complaints so that we no longer must manage them.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

One alternative for funding of this work is to fund it through the Minor Rebuild business case. However, the Minor Rebuild business case is historically tapped to the maximum allowable level every year and adding this cost would only make it worst.

Distribution System Enhancements

Another alternative considered was to absorb this cost into our existing budget. However, considering that the East Region has a $2 million budget and Colville has a $500k budget trying to absorb these costs would only reduce the funds available for each area. This in turn will delay other planned and needed projects to reinforce their systems to mitigate other issues. These issues include capacity issues, voltage issues, VAR support, wildfire mitigation, reliability issues, overload issues, relay protection issues, and safety issues. In addition, some of these projects are also tied to other customer requests and are needed to make good on previous commitments.

The East Region's budget is fully subscribed for the foreseeable future with planned work to stay ahead of load growth causing feeder capacity constraints. Below is a list of the projects planned for 2023 in the East Region.

WAL543 - CRAPO Replacement $200k

- Multiyear project budgeted through wildfire and this business case
- Wildfire mitigation, reliability issues, overload issues, protection issues

WAL542 - Lookout Pass Upgrades (multi-year) $150k

- Project is tied to another customer request
- Capacity issues

OGA611 - Extend trunk toward Carlin Bay (multi-year) $350k

- Project tied to Carlin Bay substation project which is needed for a multitude of system issues in the area.

STM632 - Smart Cap Bank $75k

- VAR support

PRV752-Reroute Settlement Road (multi-year) $50k

- Reliability and accessibility issues

SPT4S21 / SPT4S23 - Future Bronx Reinforcement $300k

- Project tied to a future Bronx substation project that will help with capacity issues and give us the ability to offload the Sandpoint substation so that it can be rebuilt

IDR253-Tie to PVW241 at Beck Rd (mult-year) $200k

- Capacity issues

RAT233/AVD151 - New Feeder Tie (multi-year) $250k

- Capacity issues

HUE141 to HUE142 Tie - Meyer Road $125k

- Capacity issues

BLU321 - Add 3rd ph Wolflodge lat $150k

- Capacity and voltage issues

BLU321 - Blue Creek Rd UG Conversion $150k

- Reliability and safety issues

Distribution System Enhancements

Total: $2,000k

Colville's budget is fully subscribed for the foreseeable future with planned work to stay ahead of load growth causing feeder capacity constraints, system reinforcements needed to stay ahead of voltage issues, and reliability/safety driven projects. Below is a list of the projects planned for 2023 in Colville.

CLV34F1 Voltage Regs – Orient $100k

- Voltage issues

ORI12F3 Mahoney Rd – Add Phase (multi-year) $150k

- Voltage issues and operational flexibility

GIF34F2 River Crossing Poles – West Side $125k

- Reliability/safety issues (poles are covered with woodpecker holes)

CLV12F2 Reconductor and Add 3rd Phase (carry over from last year) $40k

- Capacity issues

ORI12F3 Reconductor (carry over from last year) $75k

- Voltage issues (tied to a Commission complaint from last year)

Total: $490k

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The additional work identified in this funds request is still prudent because we have identified system needs in the form of equipment overloads and below code voltages. In addition, we have two Commission complaints that this additional work is intended to address. Completing this work and bring up our distribution system to standard in these areas benefits our customers because they expect this from us, and so do our regulators.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid given the nature of this change.

Distribution System Enhancements

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Cesar Godinez	BC Owner		3/14/2022
Vern Malensky	BC Sponsor	Vern Malensky	3/14/2022
	FP&A		

APPENDIX A

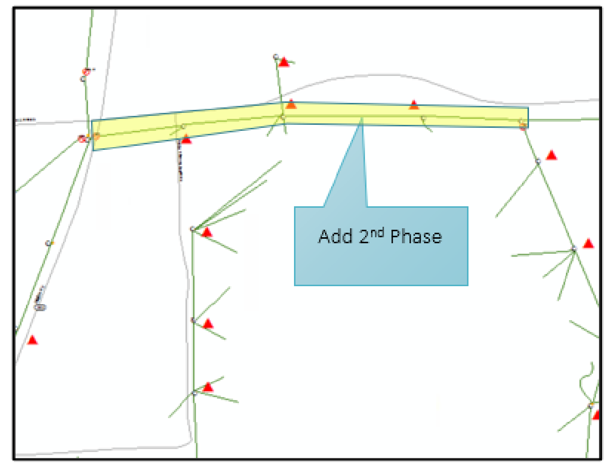
ORI12F3 –Low Voltage – Project

Project Justification:

We have been working on improving low voltage in this area for the past few years. 12/22 Cold Snap showed an improvement in voltage at "The Lakes" section of the feeder, but low voltage during that time frame was still only 103V (it was 84V last year with warmer temps, so we're improving).

Adding 2nd phase to feed down to Mahoney Rd will allow better feeder balancing that will help the voltage profile along the feeder. Currently, this lateral is single phase #6 and #8 wire and peaks over 120A.

Adding 2nd Phase along Pend Oreille Lake Rd will allow us to move the Sherry Ln lateral from Cph to Bph, reducing Cph loading in order to improve voltage on the East side of the lakes.



Project Requirements:

1. Add 2nd phase of line to feed Artman-Gibson and Mahoney Rd Laterals. Distance: 1.2mi OH, 0.5mi URD
   Budget Estimate = $200k

2. Add 2nd phase 4 spans (1500ft) along Pend Oreille Lake Rd
   Budget Estimate= $20k

Distribution System Enhancements

CLV12F4 –Low Voltage – Project

Project Justification:

Large single phase lateral at end of feeder. Fed by small wire. Customer complaints of low voltage during every cold snap.

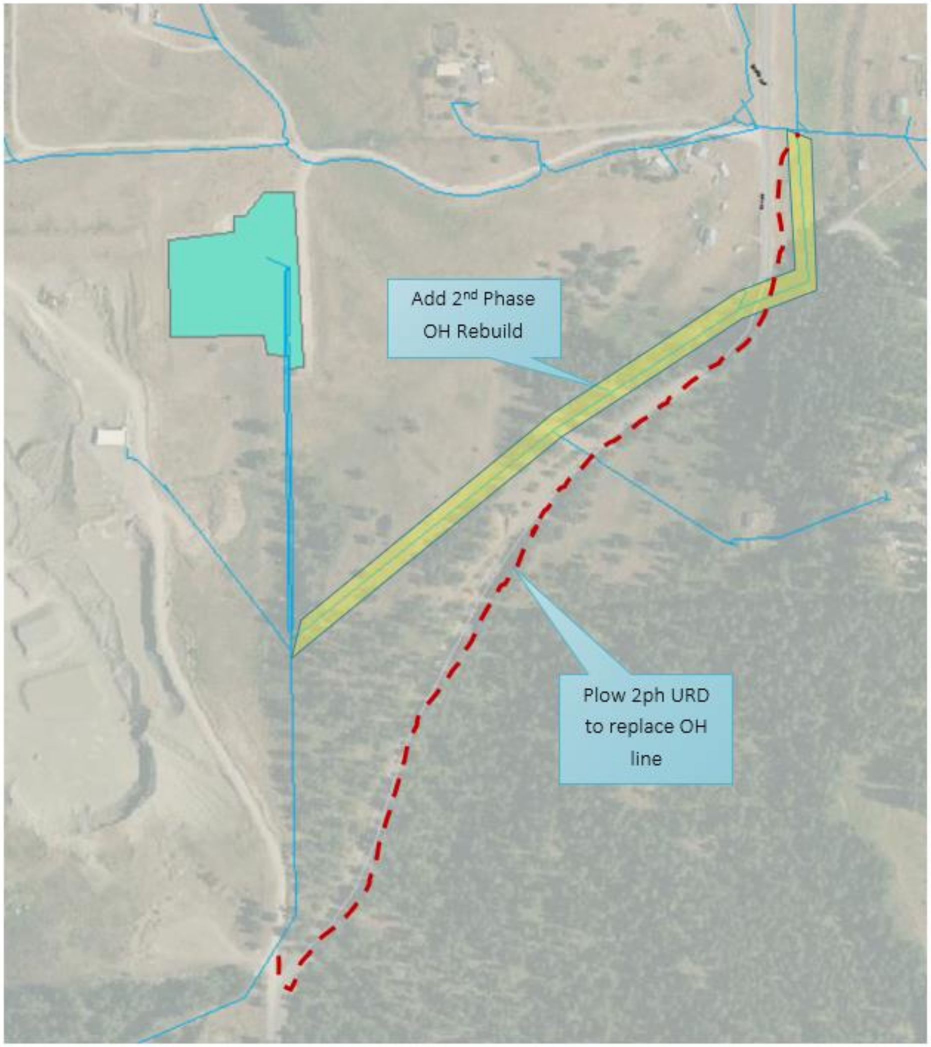
Adding 2nd phase along Knapp Rd will allow us to break up laterals heading north and west from the lateral heading east. Will reduce load by 25-30% on existing phase.

Preferred method would be to plow in 2ph URD along Knapp Rd and remove existing 1ph OH cross country line. ~0.5mi

Second option would be to rebuild existing OH line and add 2nd phase. ~0.4mi

Project Requirements:

1. Add 2nd phase of line to feed Knapp Rd Lateral. Budget Estimate = OH $50k, URD $65k



Distribution System Enhancements

KET12F2 – Low Voltage – Project

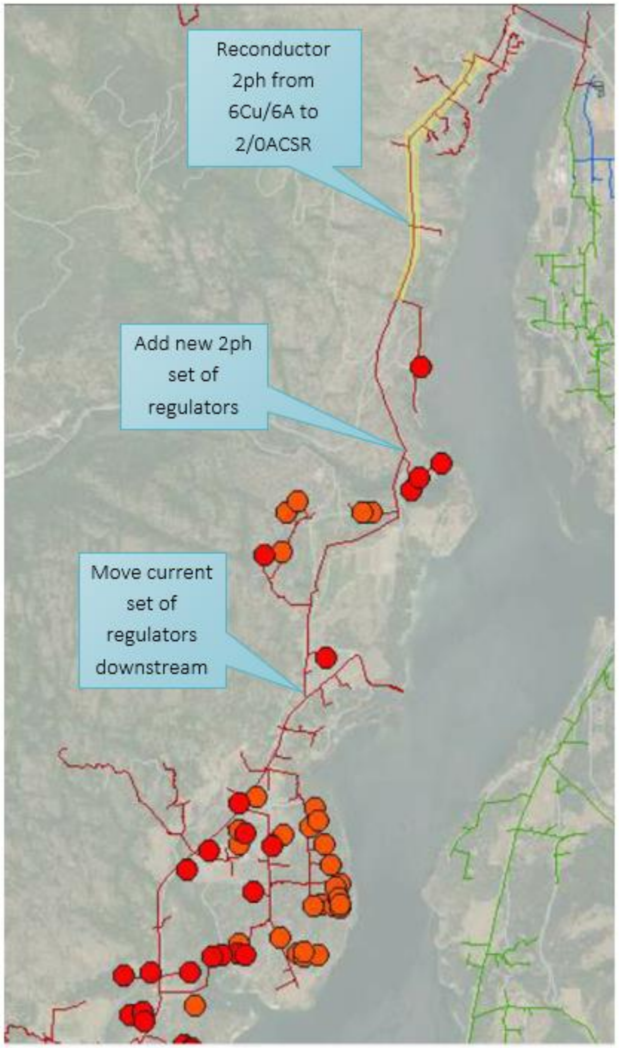
Project Justification:

End of line voltage was 107V during cold snap. Voltage drops along #6 wire sections before getting to the midline regs. Reconductoring the 6A and 6CU for the first 1.8 miles will improve the voltage enough to allow the regulators to do their job. We can break this into a multi-year project and go approximately one mile at a time.

Alternate Option – Add second set of regulators upstream of current set and move current set downstream

Project Requirements:

1. Reconductor 1.8mi of OH from #6Cu/6A to 2/0ACSR. Budget Estimate = $200k
2. Add 2nd stage of Midline regulators and move existing stage. Budget Estimate = $80k



Distribution System Enhancements

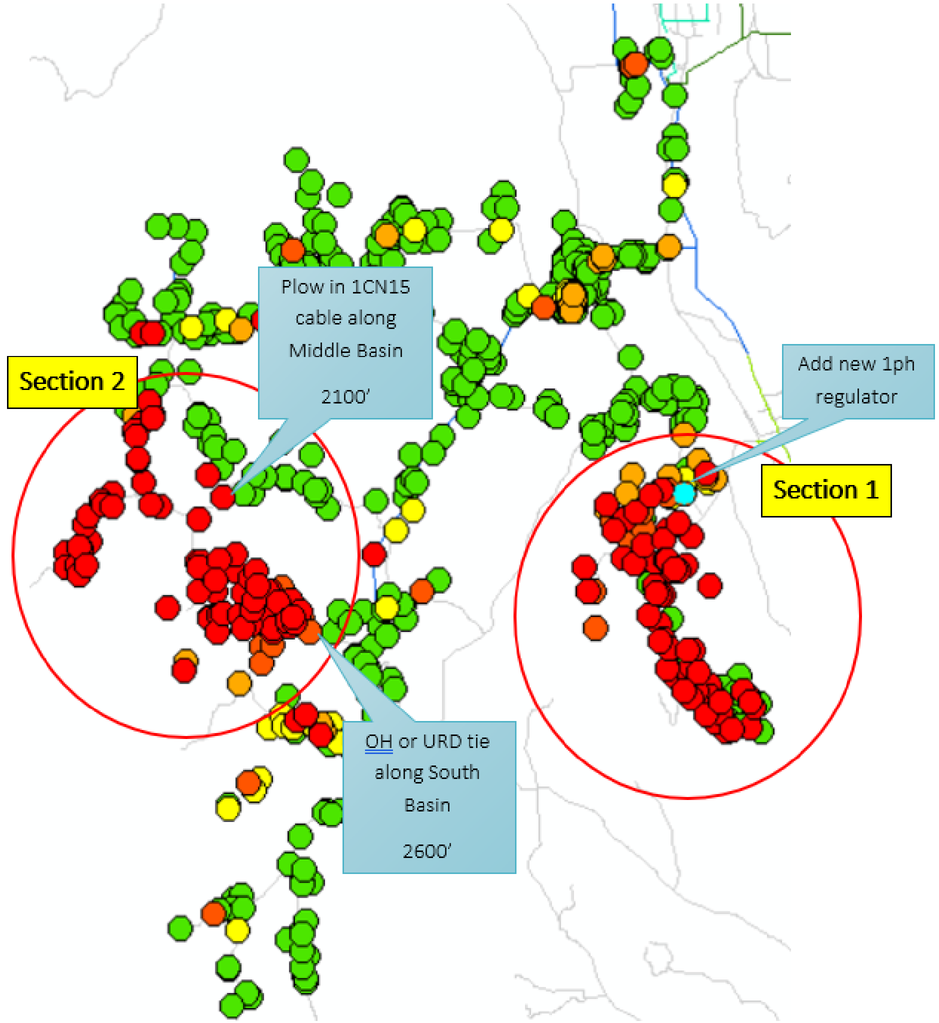
ORI12F1 – Low Voltage – Project

Project Justification:

Section 1:
End of line voltage was 108V on Bph section on southeast side. Install single phase regulator at Barzee and Skidmore.

Section 2:
End of Line voltage was 107V on West section. Install new 1CN15 section along Middle Basin Rd and re-feed the EOL section of this lateral. Plow in ~2100' of 1CN15 and cut JE1's into existing cables at each end.

Build tie along South Basin Rd ~2600' either OH or URD to re-feed middle section of this lateral.



Project Requirements:

1. Add 1ph Regulator
   Budget Estimate = $25k
2. Create new feeds (2100',2600')
   Budget Estimate = $100k

Distribution System Enhancements

CLV34F1 – Orient Low Voltage – Project

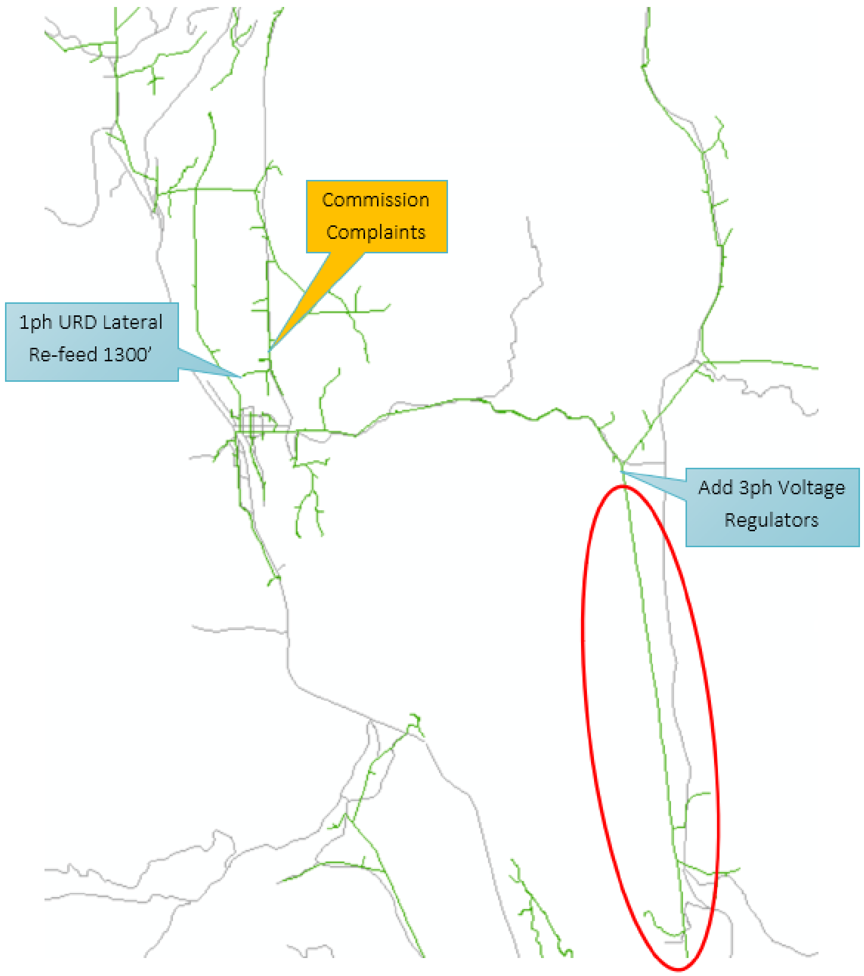
Project Justification:

We received two commission complaints after the 12/22 Cold Snap. Voltage was under 100V at meters along Rockcut Rd. Voltage is low along entire lateral.

3.5 mile stretch of #6 line (Circled) loses ~10V(120V Base) at peak. Optimal solution is to replace 3.5mi with new underground feed. Due to expense, alternate solutions provided below.

Project Requirements:

1. Add set of 3ph voltage regulators at end of 3.5 mile stretch of line.
   Budget Estimate = $100k
2. Re-feed Rockcut Rd lateral from upstream to improve voltage. New 0.25mi URD lateral tie to existing line.
   Budget Estimate = $20k



Distribution System Enhancements

BLU321 & OGA611 – December 2022 Cold Spell

Supporting documentation for funds request.

Last Updated – 02/10/2023 by Marshall Law

Summary of BLU321 System Issues Needing Immediate Follow-up

BLU321 – Eliminate SOLID Doors

- There are 4 locations where we have UG/OH risers with SOLID door cutouts (for sectionalizing) that had loading levels of about 340A, well in excess of their 300A rating. Previous to the cold snap, the highest loading levels observed on these cutouts was 277 A (excluding those situations with cold load pickup causing elevated short-term loading levels).
- This situation was presented to the distribution standards group, and their recommendation is to replace the cutouts at each of these locations with higher rated equipment. 600A JE3's will be utilized at 3 of the locations, and In-line disconnects with hard jumpers will be used at the 4^{th} location.

BLU321 – Replace C952V regulator bank

- The existing 150 A voltage regulators at Neachen Bay were loaded up to 268A during the cold snap. The winter rating with no bonus factor (these regulators were operating at boost positions greater than +8 during the cold temperatures) is 218 A. Previous to the cold snap, the highest loading levels observed on these regulators was 206 A (excluding those situation with cold load pickup causing elevated, short-term loading levels).
- Replacing these regulators with 328 A regulators with communications will not only allow for the needed capacity at this location, but also provide operational information at a key location on the BLU321, just upstream of the Gozzer Ranch development.

Summary of OGA611 System Issues Needing Immediate Follow-up

OGA611 – Replace C620V regulator bank

- The existing 150 A voltage regulators in Harrison were loaded up to about 127 A during the cold snap, which is within their amp rating. However, two of the 3 phases were operating at Boost 16 (full boost). The SynerGi model shows that areas of low voltage was being delivered to customers for portions of the feeder electrically upstream of these regulators.
- The existing location of these regulators is very congested and difficult to access. By replacing the regulator bank, a better location can be chosen that is further electrically upstream, and will solve two issues at once (the poor access and unacceptable voltage).
- By replacing these with new 219 A regulators with communications, there will be sufficient capacity to accommodate growth on the feeder, as well as an ability to provide key operational information for this location on the OGA611 feeder, just upstream of the City of Harrison.
- Note also that the C-ph regulator has a counter read of over 633,000 steps, which would meet the criteria for replacement (as I understand it).

Distribution System Enhancements

<u>Peak Loads Observed at various locations on BLU321 feeder</u>

<u>BLU321 VCR</u>

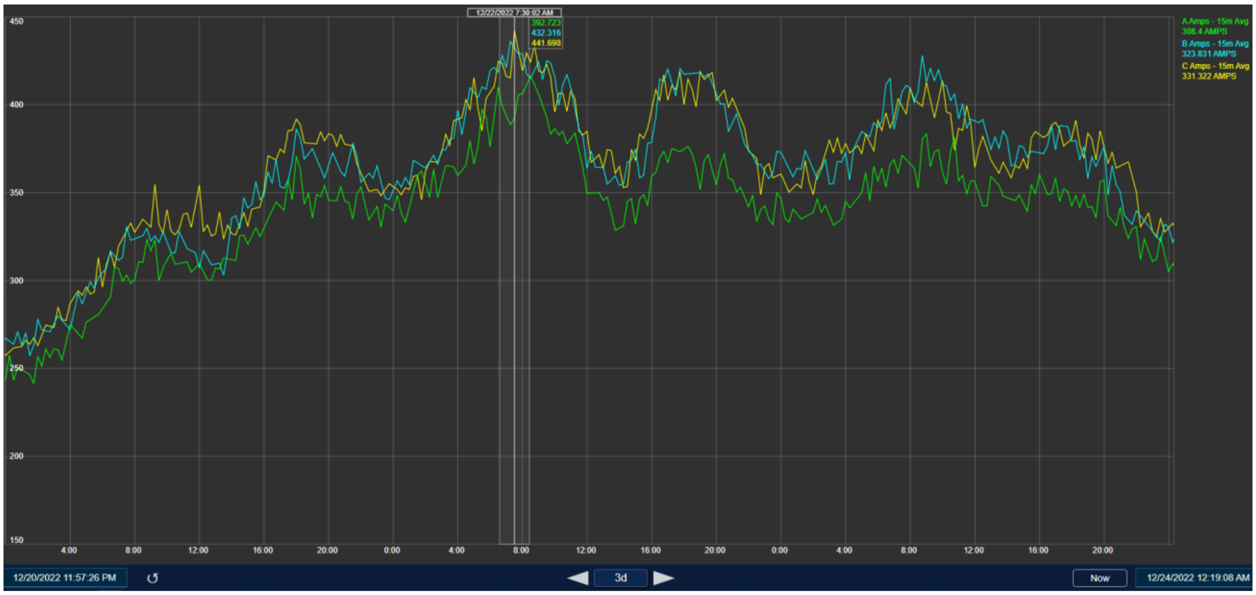
12/22/22 @ 7:31 AM

A = 393 A

B = 432 A

C = 441 A

AVE = 422 A



<u>Midline Recloser ZC869R (Wolf Lodge Branch)</u>

12/22/22 @ 7:31 AM

A = 40 A

B = 91 A

C = 85 A

AVE = 72 A

P = 1711 kW, Q = -86 kVAR, S = 1713 kVA, PF = -99%

12/22/22 @ 6:20 PM (Actual peak time for this device)

A = 38 A

B = 95 A

C = 86 A

AVE = 73 A

Distribution System Enhancements

<u>Midline Recloser ZC150R (Arrow Ranch)</u>

12/22/22 @ 7:31 AM

A = 287 A
B = 338 A
C = 331 A
AVE = 318.7 A

P = 7247 kW, Q = -135 kVAR, S = 7248 kVA, PF = -99%

<u>Midline Recloser ZC883R (Neachen Bay, near Gozzer)</u>

12/22/22 @ 7:31 AM

A = 251 A
B = 251 A
C = 244 A
AVE = 249 A

P = 6049 kW, Q = -165 kVAR, S = 6051 kVA, PF = -99%

12/22/22 @ 6:35 AM (Actual peak time for this device)

A = 267 A
B = 248 A
C = 236 A
AVE = 250 A

<u>Midline Regulator ZC953V (Turner Bay)</u>

12/22/22 @ 7:31 AM

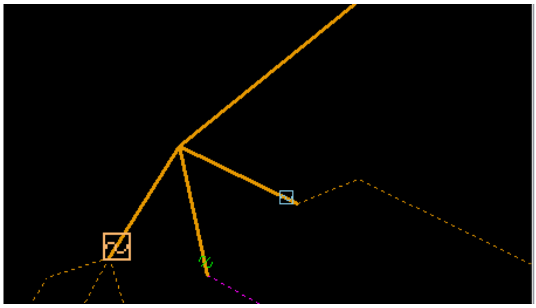
A = 48 A
B = 41 A
C = 77 A
AVE = 55 A

Distribution System Enhancements

P = 1427 kW, Q = -42 kVAR, S = 1427 kVAR, PF = 100%

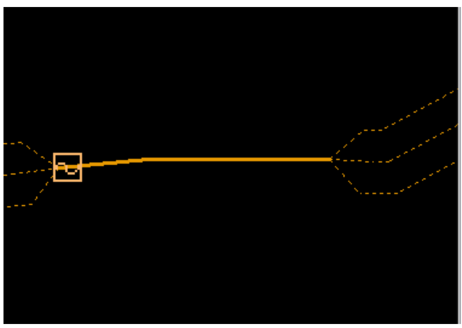
Overloaded fuses and cutouts

SOLID Doors at pole# 121820 near Higgens Point → Loaded to 342 A (114% of rating).



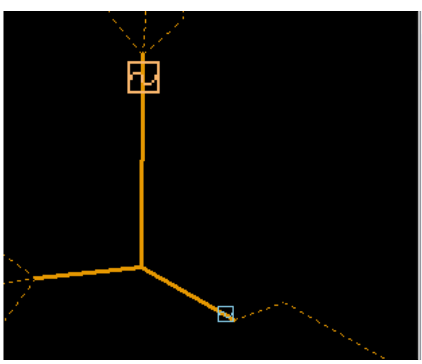
Cont Loading	108%	114%	114%	112%	114%
Emer Loading	108%	114%	114%	112%	114%
Max Thermal MVA	2.37	2.37	2.37	2.37	7.10
Consumption					
Conn kVA Into	7566	8286	8420	8091	24272
Conn Cust Into	431	466	512	470	1409
Losses					
kvar Loss Into	318.6	431.2	480.2	410.0	1230.0
kW Loss Into	190.7	278.0	282.8	250.5	751.5
Actual values					
Actual kV	7.89	7.87	7.90	7.89	7.89
Actual Amps	323.83	340.56	342.07	335.40	342.07
Actual V Deg	-1.7	-122.0	117.9	-5.7	---
Actual A Deg	6.6	-111.3	125.7	7.0	---

SOLID Doors at pole# 121824 near Beauty Bay → Loaded to 340 A (113% of rating).



Cont Loading	108%	113%	112%	111%	113%
Emer Loading	108%	113%	112%	111%	113%
Max Thermal MVA	2.32	2.32	2.32	2.32	6.95
Consumption					
Conn kVA Into	7551	8261	8225	8012	24037
Conn Cust Into	429	465	491	462	1385
Losses					
kvar Loss Into	286.4	395.1	441.6	374.3	1123.0
kW Loss Into	133.4	214.8	219.6	189.3	567.8
Actual values					
Actual kV	7.73	7.71	7.73	7.73	7.73
Actual Amps	323.54	340.23	336.27	333.21	340.23
Actual V Deg	-2.7	-123.2	116.8	-9.0	---
Actual A Deg	6.4	-111.6	124.4	6.4	---

SOLID Doors at Pole# 121821 near Moscow Bay → Loaded to 340 A (113% of rating).



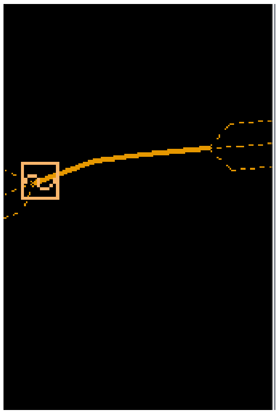
Info

Results

Cont Loading	---	113%	---	113%	113%
Emer Loading	---	113%	---	113%	113%
Max Thermal MVA	---	2.30	---	2.30	2.30
Consumption					
Conn kVA Into	---	8261	---	8261	8261
Conn Cust Into	---	465	---	465	465
Losses					
kvar Loss Into	---	384.2	---	384.2	384.2
kW Loss Into	---	195.9	---	195.9	195.9
Actual values					
Actual kV	---	7.67	---	7.67	7.67
Actual Amps	---	340.19	---	340.19	340.19
Actual V Deg	---	-123.5	---	-123.5	---
Actual A Deg	---	-111.6	---	8.4	---

Distribution System Enhancements

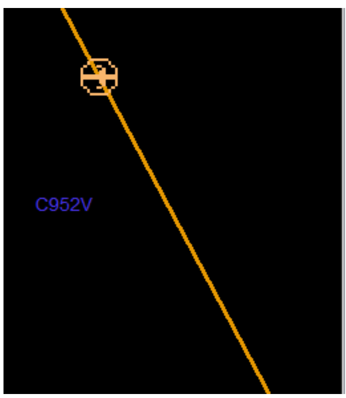
SOLID Doors at Pole# 121804 near Moscow Bay → Loaded up to 340 A (113% of rating).



Cont Loading	100%	113%	112%	108%	113%
Emer Loading	100%	113%	112%	108%	113%
Max Thermal MVA	2.29	2.29	2.29	2.29	6.88
Consumption					
Conn kVA Into	6936	8261	8225	7807	23422
Conn Cust Into	388	465	491	448	1344
Losses					
kvar Loss Into	264.7	375.8	422.7	354.4	1063.2
kW Loss Into	104.3	181.6	186.8	157.6	472.7
Actual values					
Actual kV	7.65	7.63	7.64	7.64	7.64
Actual Amps	300.10	340.15	336.21	325.33	340.15
Actual V Deg	-3.3	-123.8	116.3	-10.8	---
Actual A Deg	4.9	-111.6	124.3	5.9	---

Other Overloaded Equipment

C952V Regulators – Loaded to 268 A (123% of Rating)



Cont Loading	121%	123%	118%	121%	123%
Emer Loading	121%	123%	118%	121%	123%
Max Thermal MVA	1.73	1.73	1.73	1.73	5.18
Consumption					
Conn kVA Into	6196	6503	5992	6231	18692
Conn Cust Into	353	358	318	343	1030
Losses					
kvar Loss Into	109.6	139.2	173.2	140.7	422.0
kW Loss Into	57.5	71.0	116.3	81.6	244.8
kvar Loss	2.4	3.8	2.3	2.8	8.5
kW Loss	1.3	1.4	1.3	1.3	4.0
Actual values					
Actual kV	7.94	7.90	7.93	7.92	7.92
Actual Amps	264.35	268.25	257.61	263.37	268.25
Actual V Deg	-7.2	-129.0	110.8	-25.4	---
Actual A Deg	0.7	-121.0	118.6	-0.6	---

These are 150A Regulators

Tap positions

A	B	C
8	10	8

Distribution System Enhancements

			Load Current Ratings (A) With Additional Ratings Included (See Table 2)		
Rated Voltage (kV)	Rated kVA	Nameplate Load Current Ratings (A) (30°C)	Regulator Restricted to ±5% Volts (N2)	0°C Rating (N2)	40°C Rating (N2)
7.62	76.2	100	160	146	95
	114.3	150	240	218	143
	167	219	350	319	208
	250	328	525	478	312

N2. The ampacity of the regulator varies depending on the following factors:

- The regulation range (buck/boost) allowed.
- Ambient temperature at which the device is operating.
- Temperature (°C) rise rating of the insulation.

Table 1 below displays the regulator KVA rating, nameplate load and load current rating at various ambient temperatures. The load current ampacity values incorporate the 12% temperature rise bonus rating (R1) and Ambient Temperature Bonus Factors (R1) as listed in Table 2.

Add an additional 60% of 30°C rating if the operating range is limited to plus or minus 5%. Refer to Substation SVL ratings calculations.

OGA611 – Winter Peak Analysis

Source Id	Amps A	B	C	Avg	N
Feeders for O Gara 115/13 kV					
OGA611	140	127	155	141	25

OGA611 Feeder Breaker (based on 1-11-2023 sub inspection)

IA = 140 A

IB = 126 A

IC = 155 A

ZC613R Peak @ 12-22-22 @ 9:00 AM

IA = 82 A

IB = 105 A

IC = 149 A

ZC618R Peak @ 12-22-22 @ 9:00 AM

IA = 46 A

Distribution System Enhancements

IB = 35 A

IC = 67 A

ZC616V Peak @ 12-22-22 @ 9:00 AM

IA = 46 A

IB = 26 A

IC = 40 A

Harrison Regulators – The regulators appear to be within their amp rating, even when considering they are likely running at full boost during high loading periods.

IA = 80 A

IB = 104 A

IC = 127 A

Per model, step positions were:

Aph → Boost 5

Bph → Boost 16

Cph → Boost 15

			Load Current Ratings (A) With Additional Ratings Included (See Table 2)		
Rated Voltage (kV)	Rated kVA	Nameplate Load Current Ratings (A) (30°C)	Regulator Restricted to ±5% Volts (N2)	0°C Rating (N2)	40°C Rating (N2)
7.62	76.2	100	160	146	95
	114.3	150	240	218	143
	167	219	350	319	208
	250	328	525	478	312
	333	438*	668	638	417
	416.3	548*	668	668	522

Distribution System Enhancements

The midline inspection data taken after the cold snap confirms that B & C phases are going to full boost. This confirms the SynerGi model's results that show unacceptable low voltage upstream of these regulators.

Inspection Date: 1-31-23 **Inspector:** T. CRAWFORD

Regulators:

Instruction: Check all components listed. Problem conditions to be noted in comments listing the serial number & phase.

Bushings condition
Lightning Arrestors condition
Tank/Oil Level condition
Reset Drag Hands

C620V (HARRISON) - 1ST STAGE

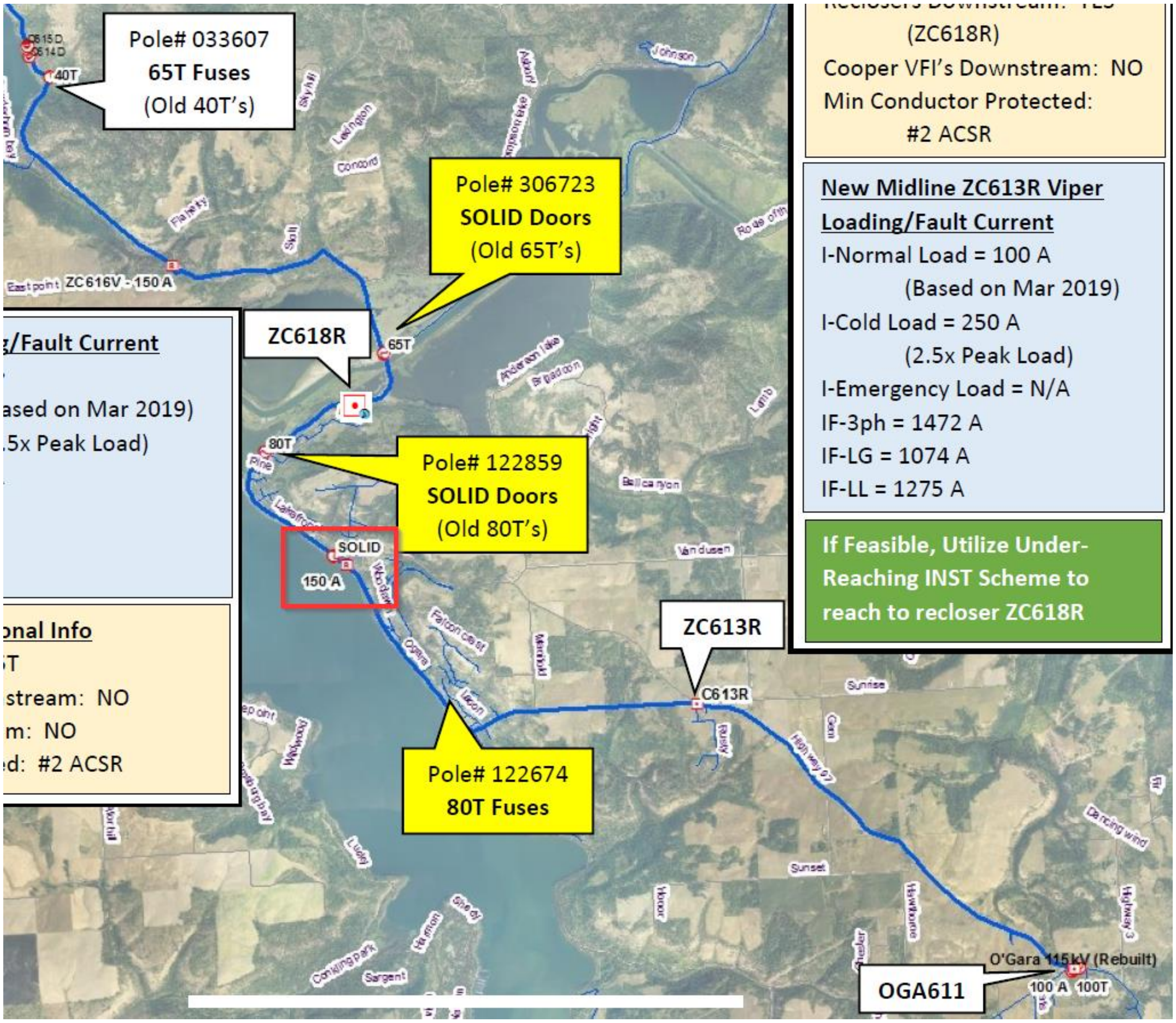
S# M-047237PDP	A	Counter 255198	Min -3	Present 5	Max 7
S# M577743PJR	B	Counter 046902	Min 2	Present 7	Max 16
S# M-047234PDP	C	Counter 633947	Min 1	Present 8	Max 16

Distribution System Enhancements

BLU321 Overview Map – Pertinent locations shown

Distribution System Enhancements

OGA611 Overview Map – Pertinent location shown



Distribution System Enhancements

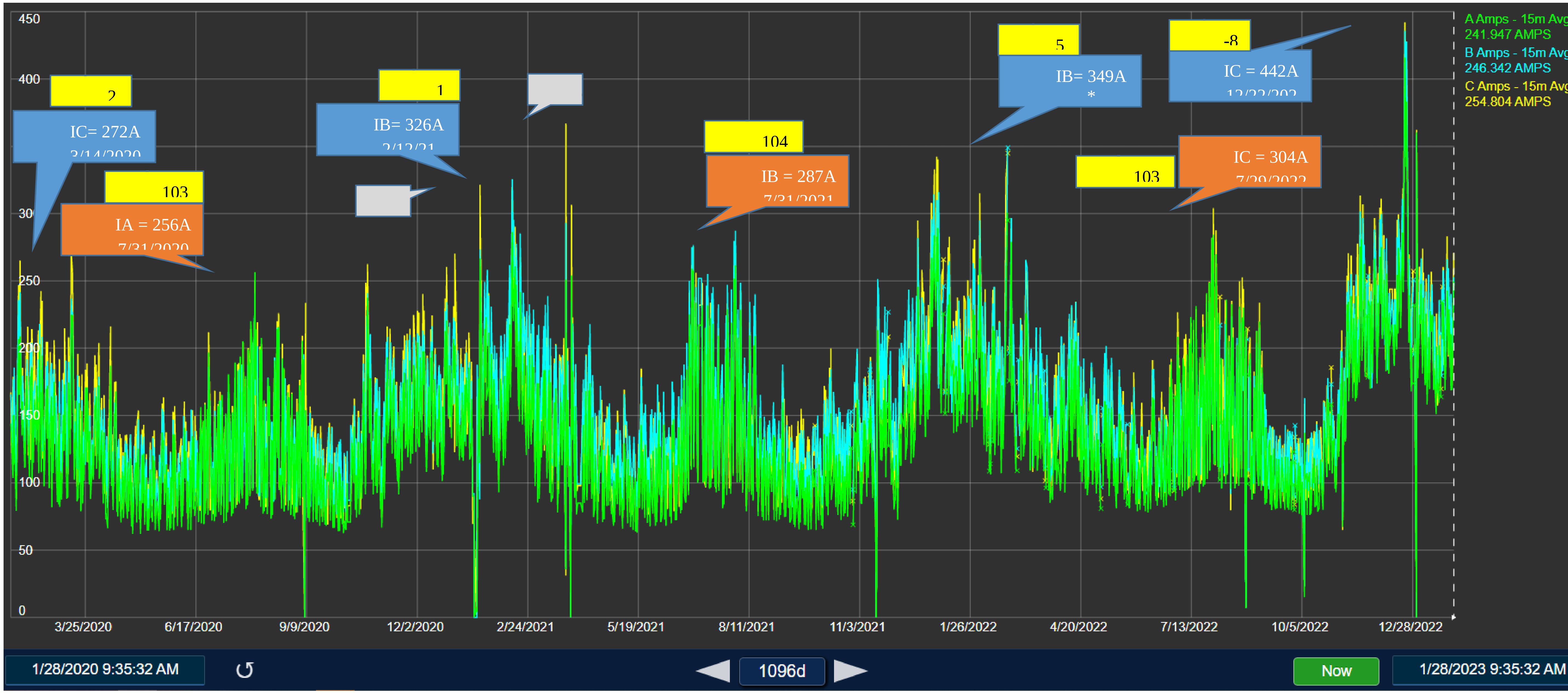
BLU321 – Feeder Loading over last 3 years

Notes:

1) The 15 minute average amp values are shown.

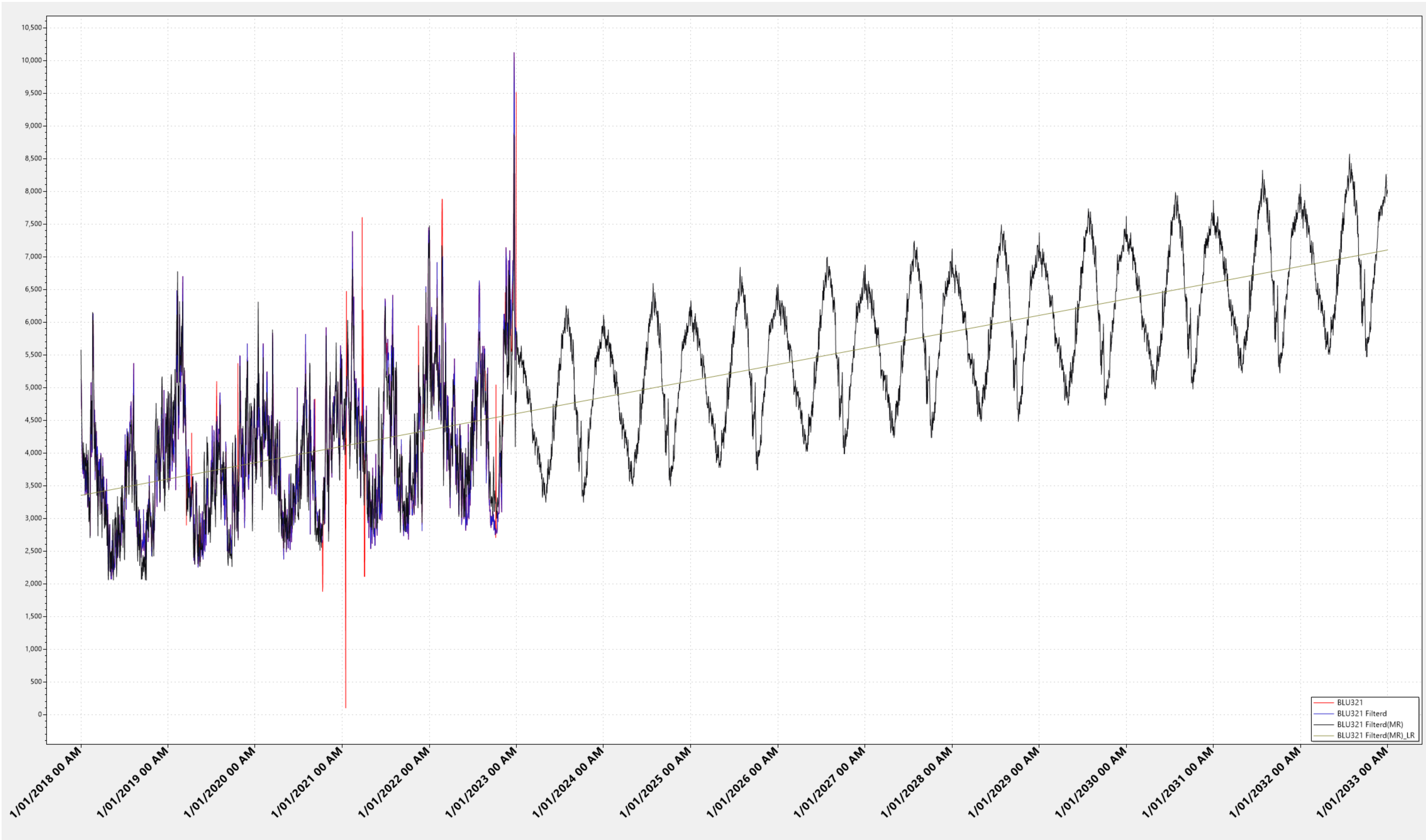
2) The temperatures displayed are the maximum (or minimum) temperatures from Beacon on that day, not necessarily at the time the peak occurred.

* Indicates comm's were lost on that day, so exact peak and time of peak are not known.

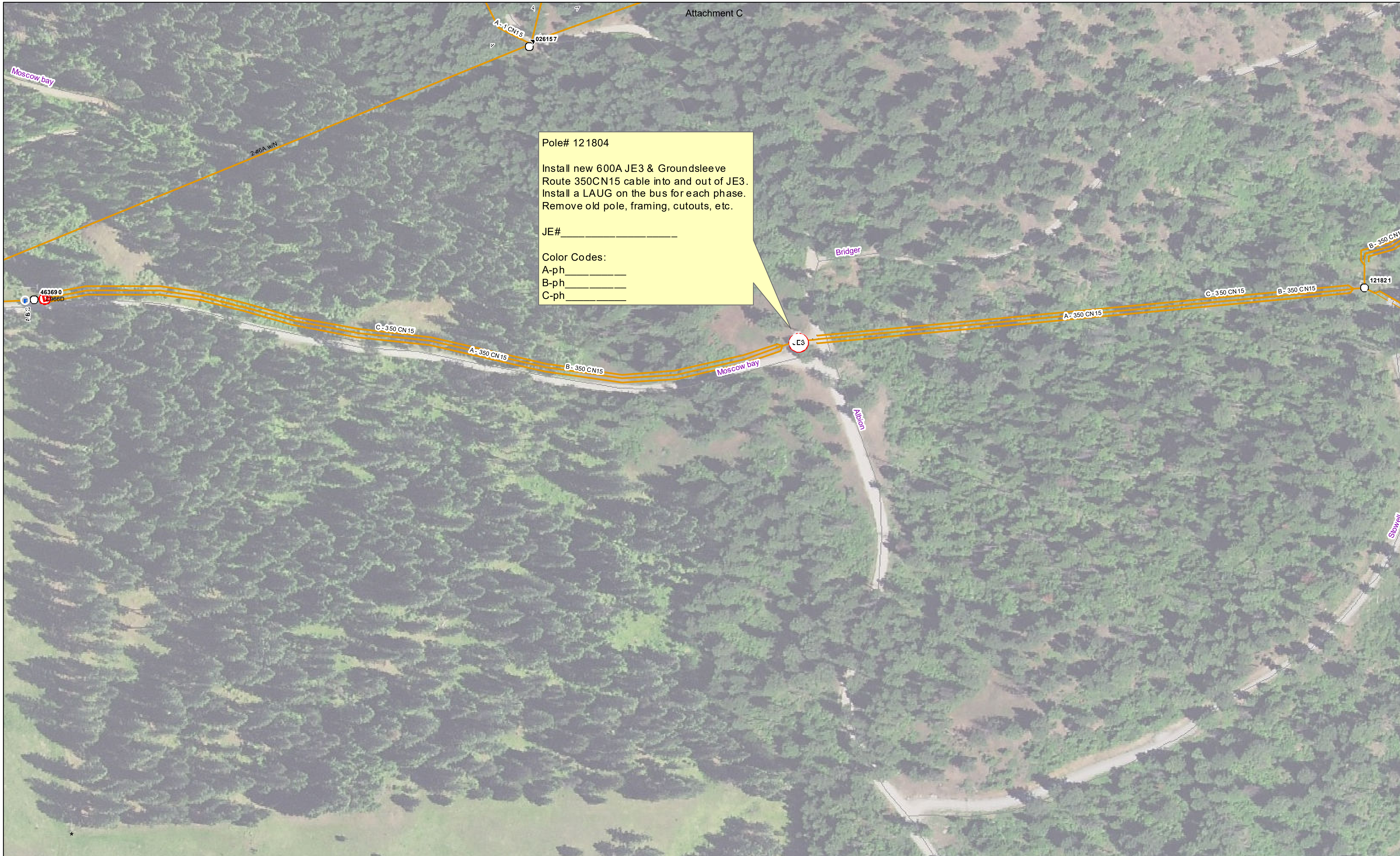


Distribution System Enhancements

Per Erik Lee, growth rate over last 3 years was 5.97%. If you look back over the last 5 years, it is 7.46%.



Attachment C



NOTICE: THIS IS NOT A LEGAL DOCUMENT

Locations of Avista Utilities' facilities on this map are approximate only. Changes to facilities may have occurred since the last update of this map. Review of this map is not an acceptable substitute for compliance with RCW Title 19, chapter 122, which includes notification of "One Call" before start of work.

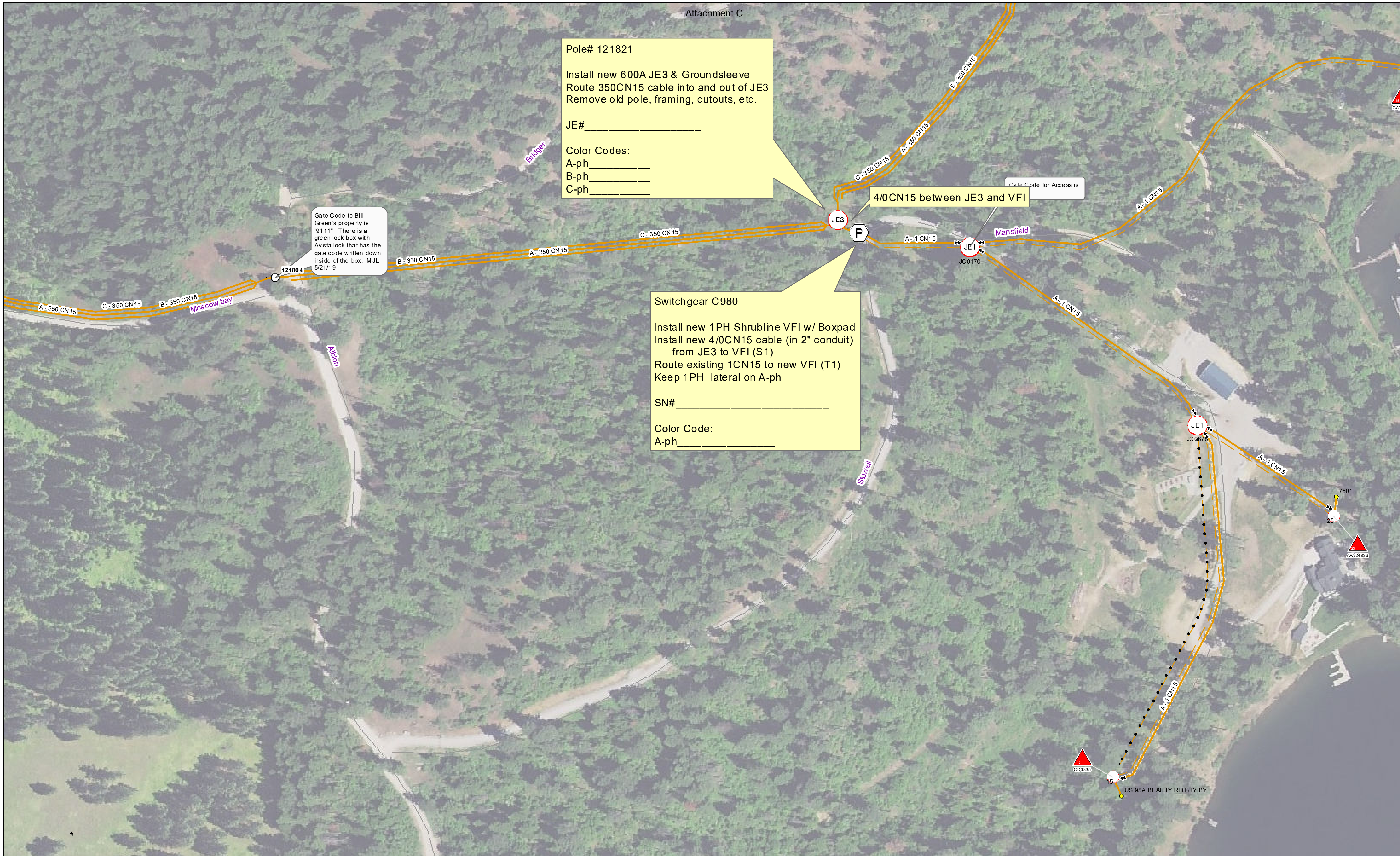
Printed: 01-25-2023

Route To: Marshall Law

1 inch = 150 feet

WO 1027120663 - Eliminate Pole 121804

Attachment C



Avista Utilities

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Locations of Avista Utilities' facilities on this map are approximate only. Changes to facilities may have occurred since the last update of this map. Review of this map is not an acceptable substitute for compliance with RCW Title 19, chapter 122, which includes notification of "One Call" before start of work.

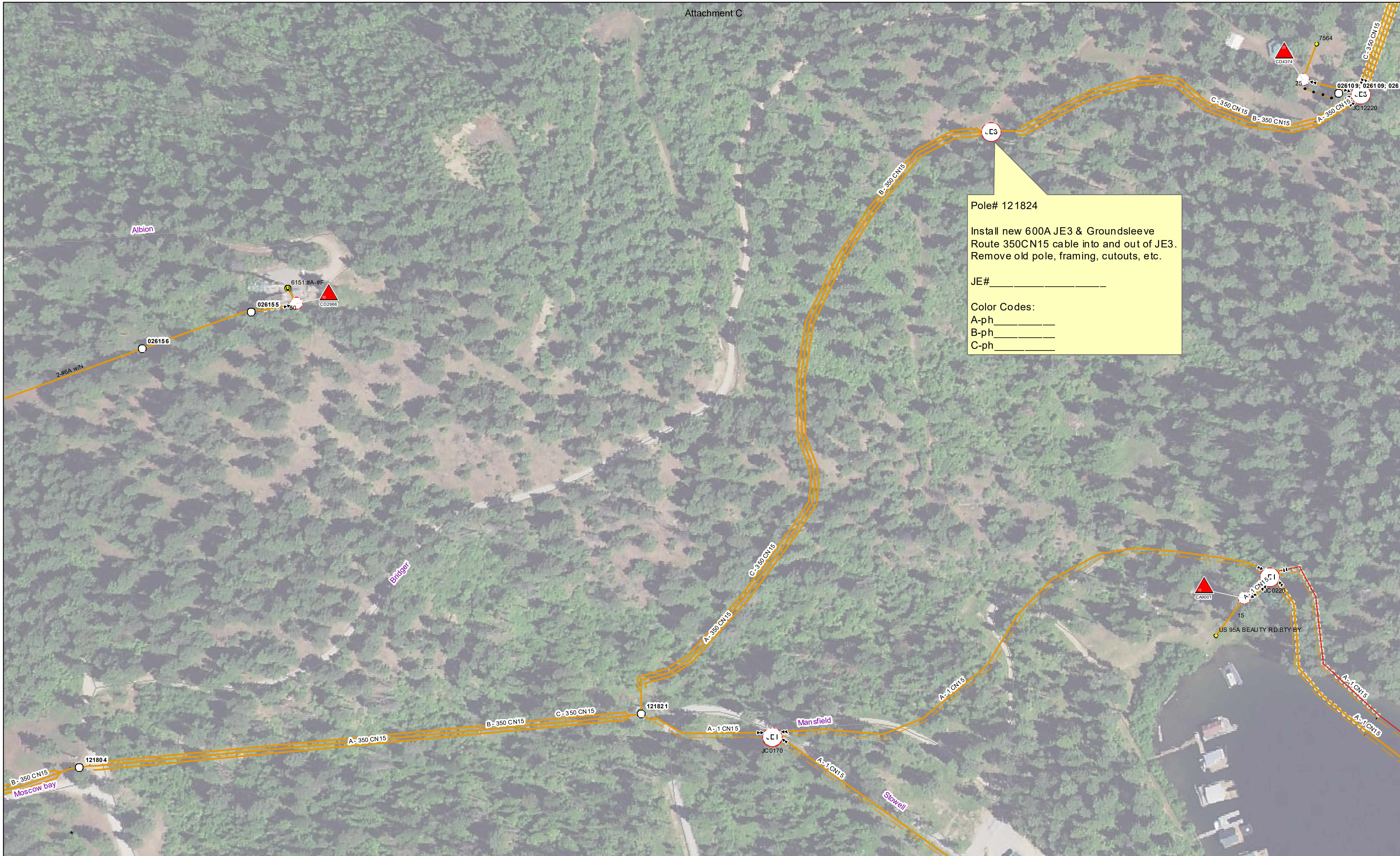
Printed: 01-25-2023

Route To: Marshall Law

1 inch = 150 feet

WO 1027119845 - C980 VFI

Attachment C



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Printed: 01-25-2023

Route To: Marshall Law

1 inch = 150 feet

WO 1027120814 - Eliminate Pole 121824

AVISTA Utilities

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Locations of Avista Utilities' facilities on this map are approximate only. Changes to facilities may have occurred since the last update of this map. Review of this map is not an acceptable substitute for compliance with RCW Title 19, chapter 122, which includes notification of "One Call" before start of work.

Printed: 01-25-2023

Route To: Marshall Law

1 inch = 100 feet

WO 1027121062 - Higgins Pt

Distribution System Reinforcements

1.0 CHANGE REQUEST #4 – 07/11/2023

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
7/11/2023	*Scope Change*	4	$8,820,000	$3,048,000		
3/14/2023	*Scope Change*	3	$7,750,000	$1,070,000	$1,070,000	$8,820,000
1/17/2023	*Scope Change*	2	$7,000,000	$675,000	$0	$7,000,000
1/17/2023	*Scope Change*	1	$7,000,000	$750,000	$750,000	$7,750,000

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
7/11/2023	*Scope Change*	$747,467	$1,005,776	$8,820,000	$11,868,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Distribution System Reinforcements

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Change Request #4 – 7/11/2023:

Considering our current trend in the capatial spend, we are requesting additional funds for our Distribution System Reinforcements business case. This will allow us to complete projects that are in our plans but have not received funding yet. All the projects listed below will improve system capacity, reliability, or fire safety (not covered by Wildfire Resiliency). The projects listed below are the next projects in our plans to complete and funding them now will help us reduce the backlog of work we have for our business case. The total ask to complete every project listed below is $3.48M, however, we can accommodate incremental funding approvals, ideally of $500k or larger.

Spokane/Deer Park:

For Spokane/Deer Park, we would pull in projects that are currently on our 2024 list of projects. Following is a prioritized list of a few of them that we could pull in to 2023 construction.

Deer Park

COB12F2 Dx UB on COB 115kV Tap (3mi 556AAC Dx UB, 1.2mi 3ph 556AAC, $1.87M) → For 2023, we could pick off the following portions of this project.

COB12F2 – Add 3ph 556AAC down Hatch Rd (1.2mi, green field, $240k)
COB12F2 – Add 3ph 556AAC Dx UB on Existing Steel Tx Poles (1.0mi, green field, $200k) – this is dependent on Tx analysis of existing steel poles.

Spokane

3HT12F2 Main Ave Recond to 2/0ACSR (Freya to Haven, 0.5mi, Fuse small wire lats, Correct dip fuse size to 1500kVA, Future Playfair Loop Feed, $200k)

BEA12F2 Longfellow Reconductor for Vistas at Beacon Hill Apts (0.5mi, #6CU to 556AAC, $200k)

3HT12F3 / 3HT12F6 Recond 2/0 Switch #980 (1700ft/0.32mi, on Grand/Sumner behind Sacred Heart, $160k)

The primary drivers for each of these projects is to increase capacity for area load growth, as well as to provide load relief on existing feeders that are at capacity (via load transfer).

SPO/DEP Total = $1M

East Region:

We've compiled a list of potential projects that could be added into our work plans and we feel could be completed in 2023 if funding were to come available in Q3. Below is a list of those projects, their current status, and cost estimate. Once given the green light to pursue any of these, we feel we can act quickly and get the money spent this year. All of these have either a project diagram put together or a completed design.

CDA Area

PVW241 Beck Road and Seltice – Designed Cost Estimate = $120k
100% designed and ready for construction (W.O. 1027103394)

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Distribution System Reinforcements

Would likely be constructed in 2024 if no funds in 2023

BLU321 Wolf Lodge Creek Add 2nd Phase (Part 2) – Designed Cost Estimate = $80k
100% designed and ready for construction (W.O. 1027028215)
Would likely be constructed in 2024 if no funds in 2023

SPL361 Spirit Lake Bay Crossing Removal (Finney's Bay) – Engineering Estimate = $75k
Planned for construction in 2023 with Minor Blanket funding
Final routing of cable still being determined
Easement from Inland Empire Paper will be required, they have verbally agreed in concept to providing an easement.

BLU321 3rd Phase to Wolf Lodge (Conduit Work) – Engineering Estimate = $300k ($150k additional ask for 2023 if funds are available)
Project scoping is completed (PRD created), easement acquisition process is well underway
$150k is budgeted for 2023 with Distribution Enhancements, but that will not cover all of the conduit work required
Moving an additional $150k into 2023 would help this multi-year project get finished in 2 years instead of 3.

St. Maries Area

STM631 Mutch Creek Part 2 (23rd & Washington) – Engineering Estimate = $175k
Project scoping is completed (PRD created), easement conversations with property owner have occurred
Detailed design is underway (Chris Sands taking the lead on design).
Would likely be constructed in 2024 if no funds in 2023

Kellogg Area

MIS431 Hardy Gulch UG Conversion – Designed Cost Estimate = $60k
100% designed and ready for construction (W.O. 1022911215)
Multiple fires have been started by OH line in this area in recent years.
MIS431 is remarkably not an elevated WUI tier feeder, so this will not be addressed by Grid Hardening

MIS431 Tamarack Ridge UG Conversion – Designed Cost Estimate = $75k
100% designed and ready for construction (W.O. 1027000999)
Long spans, wire slap is common in winter with ice/snow loading.

MIS431 Black Rock Road UG Conversion – Engineering Estimate = $50k
Project scoping is completed (PRD created), easement conversations with property owner have occurred
Eliminates 2000' section of poor accessed/treed OH line

PIN443 Wall Ridge Road UG Conversion – Engineering Estimate = $30k
Project scoping is completed (PRD created), easement conversations with property owner have occurred
Eliminates a long OH service that is attached to dead and dying trees

PIN443 Klette Road UG Conversion – Engineering Estimate = $100k
Project scoping is completed (PRD created), no private easements are anticipated to be required
Eliminates several long spans of overhead line, some of which are difficult access.

MIS431 CCC Road UG Conversion – Engineering Estimate = $150k
Project scoping is completed (PRD created), no private easements are anticipated to be required
Wire is in poor condition (many splices), several poor access poles need to be replaced (red tagged) in the section of OH line.

Distribution System Reinforcements

Sandpoint Area

SPT4S23 Bonner Mall UG Replacement – Estimate = $175k
Rough design complete – may be able to share costs with gas since also has Aldyl-A pipe
Condition justified UG replacement of old cable and JE's for about 1500'

East Region Total = $1.23M

Big Bend:

Othello

L&R516 Foley to Sutton Reconductor to 556 - 1 mile to improve capacity and eventually establish tie to L&R512. $250K

L&R516 Reynolds to Hwy 17 Reconductor to 556 – 1 mile to improve capacity and eventually establish tie continuation of above $350K

L&R516 Hwy 16 to Steele Reconductor to 556 – 1 mile to improve capacity and eventually tie to 512 continuation of above $250K

Davenport

North of Long Lake Bridge plow in 1 mile of conduits to tie FOR12F2 to L1312F1 for reliability and capacity $100K

DVP12F1 reconductor 1000 feet to 556 along 6th and add air switch to tie DVP12F1 and DVP12F2 for additional reliability and backup $100K

GIF34F1 Enterprise Rd plow in three phase about 1 mile to add two phases because of load growth. Adds flexibility and reliability. $200K

All jobs have been designed and we already have the conduit for Long Lake – Ford tie

Big Bend Total = $1.25M

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Cesar Godinez	BC Owner		1/18/2022
Vern Malensky	BC Sponsor	Vern Malensky	07.12.2023
	Steering Committee (If applicable)		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Downtown Network – Performance & Capacity

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

There is one project being performed under this business case that does not Transfer To Plant (TTP) monthly: the Vault Integration Project. TTP on this project occurs when major milestones are met that cause part of the system to become "used and useful". We did not meet a major milestone in 2023 because we re-organized the second half of this project such that two quadrants of the network (both Post St Networks) would be worked simultaneously instead of consecutively. We are planning to start commissioning both Post St networks in April of 2024 and expect to finish and TTP the rest of the project by end of 2024.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

There are no significant cost overruns, just schedule delays due to reorganization of how the project is being worked .

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets, other than a slight delay to when they may be fully realized (due to the delay in completing the project). That being said, we are no longer doing patrol work during switching on the 60% of the system that has been commissioned, so some of the offsets are being realized presently.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

DIRECTOR SIGNATURE:

Paul D. Good

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Electric Replacement and Relocation

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Electric Replacement and Relocation program, also known as Road Moves, is driven by compliance that is mandated by the "Franchise Agreement" contracts with the city, state entities and permits entered by railroad owners. With road moves, as soon as the spend happens and the work is complete it provides an immediate benefit to the customer.

The Company's Transfer To Plant (TTP) variance from what was filed in 2022 for 2023 was due to an unprecedented increase of mandatory work required in our service territories. 2022 saw a significant increase in Road Moves spending with funds being requested/approved by the Capital Planning Group (CPG) in July, August, October, and November. The approved 2022 budget and forecasted TTP was approx. $5.4m, however, this business case had spent over $10m by the end of the year. This resulted in Road Moves starting 2023 with approximately $3.6m in funds available to transfer to the plant. A majority of these funds were transferred to plant in May of 2023. As the extent of this unprecedented mandatory work was not fully realized until Q4 of 2022, we would expect a variance from what was filed in 2022 for 2023.

This increase in spending was needed to complete mandated work and to prevent the Company from falling out of compliance with the franchise agreement.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This business case is discussed at the Operations Round Table with the director and business case owners monthly. Once a decision to submit a change request is made, it will be presented to the CPG for final approvals. However, as this TTP variance was largely due to work performed in 2022, there were no updates/requests submitted to CPG in 2023.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

None.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

Paul D. Good

DIRECTOR SIGNATURE:

Paul D. Good

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Electric Storm

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Electric Storm Business Case is focused on restoring Avista's transmission, substation, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disaster where assets are damaged. These storm events are random and often occur with short notice. As the amount transferred to plant is a reaction to the impact of weather events on Company's infrastructure, it can be difficult to predict the amount that will be transferred each year. Therefore, the annual budget amount is determined based on the historical average rate of capital restoration work. The impact from weather events in 2023 was lower than the average of the last 5 years, resulting in a variance from what was filed in our 2022 WA General Rate Case.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

There were no significant cost overruns in 2023.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no offsets to O&M. The costs associated with repairing damages as a result of a weather storm event or a natural disaster would be covered through a different business case. Damages from these events must be repaired, regardless of funding.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: Paul D Good

DIRECTOR SIGNATURE: Paul D Good

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Endpoint Compute and Productivity Systems

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Endpoint Compute and Productivity Systems business case includes, but is not limited to, technology required every day to automate and enable business processes, such as Personal Computer (PC) hardware and associated operating systems, various handheld devices, printers, patching and configuration management systems for all endpoints, productivity tools (e.g. Office 365), etc.

The Endpoint Compute and Productivity Systems business case had planned to transfer-to-plant approximately $3.4M and ended up transferring around $2.8M, resulting in an understated transfer-to-plant amount of approximately $600k.

This is a result of work that was planned to be completed in 2023 that shifted into 2024, with an increase in transfers-to-plant for 2024. The work representing the transfer-to-plant that shifted from 2023 into 2024 is as follows.

- Citrix Product Updates – 2023 – ECPS Package 3 - $18k
- Endpoint Software Product Updates – XPU 2023 Package – $6k
- Microsoft Product Updates – 2023 – ECPS Package 2 - $197k
- Generation ConfigMgr (SCCM) Implementation - $2k
- Thin Client Replacement - $12k
- Windows 11 Hardware Readiness - $96k
- SharePoint Upgrade Phase 1 - $178k
- User Q-Drive Transition to OneDrive - $40k

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. Please see the following Capital Planning Group change request documents that represent changes to the plan from the filed general rate case amount. Through prudent governance of this business case, capital funding that was not able to be spent this year (and ultimately transferred-to-plant), was released for other areas of the business to utilize.

Release - CR01	• Citrix Product Updates - 2023 - ECPS Package 3 - Professional services were no longer required for the project and therefore those costs are being returned from the project. • Endpoint Software Product Updates - XPU Package 3 - Timing of the upgrade work occurred later in th eyear and labor was less than expected. • Sharepoint Upgrade Phase 1 - Project work was not started this year and is planned for 2024.	($151,000)
		($151,000)

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The indirect savings associated with the Endpoint Compute and Productivity Systems business case are related to avoided costs associated with lost work time by employees for having to use manual systems and tasks to communicate. The above projects and additional transfers-to-plant did not change these expected indirect offsets.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Walter Roys
28978793A9C64D0...

DIRECTOR SIGNATURE:

X DocuSigned by: Alexis Alexander
EA27BABA767F467...

Endpoint Compute and Productivity Systems

1.0 CHANGE REQUEST #CR01 – 12.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
12-2023	*Revised Cost*	CR01	$2,634,000	-$151,000		

Complete the following for the current request

CURRENT YEAR REQUESTS

Request Date	Offsets Impact			TTP Impact	
	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
12-2023	Revised Cost	$100k-$10M		$2,634,000	$2,483,000

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

Year	Funding Impact		Offsets Impact		TTP Impact	
	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

This change request does not impact 2024 or any out years.

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Endpoint Compute and Productivity Systems

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Endpoint Compute and Productivity Systems Business Case is projecting a release of $151,000 for unused funds based on current projects forecasted for 2023. As project details are defined, including professional services and internal labor, costs for 2023 are lower than originally anticipated. Based on a review of the current in flight project work for 2023, the business case can release $151,000 in funding. If this funding is not returned, it could result in needed work in other areas of the business being underfunded.

The below projects contributed to the release of funds:

- Citrix Product Updates – 2023 – ECPS Package 3 – Professional services were no longer required for the project and therefore those costs are being returned from the project.
- Endpoint Software Product Updates – XPU Package 3 – Timing of the upgrade work occurred later in the year and labor was less than expected.
- Sharepoint Upgrade Phase 1 – Project work was not started this year and is planned for 2024.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Walter Roys	BC Owner	DocuSigned by: Walter Roys 28978793A9C64D0...	Dec-19-2023 | 8:57 AM PST
Alexis Alexander	BC Sponsor	DocuSigned by: Alexis Alexander EA27BABA767F467...	Dec-19-2023 | 2:44 PM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Energy Delivery Modernization and Operational Efficiency (EDMOE)

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The EDMOE business case was expected to transfer to plant approximately $3.4M and ended up transferring approximately $7.6M. This equates to approximately $3.4M more than expected in 2023.

- Efforts inside the EDMOE business case that leverage the same labor as efforts in the ATLAS business case were prioritized and a portion of the EDMOE TTP variance is represented by the reprioritization of work between the two Business Cases.
- Numerous application upgrades, enhancements, and license purchases were also pulled forward under EDMOE in 2023, and these are called out on the Business Case change requests.
- An additional factor was project TTP shifting from 2022->2023, due to competing priorities in other areas.
  - AMI Dev: $0.78M
  - Maximo Conversion Licenses: $1.6M
  - Jana DIMP: $1.1M

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

CR1 +$814k Revised TTP
CR2 +$235k Revised TTP
CR3 +$728k Revised TTP

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The above lag in transfers-to-plant does not impact indirect offsets that have been calculated.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Mike Mudge
44C0BE3C52404B4...

DIRECTOR SIGNATURE:

X DocuSigned by: Hossein Mkdel
E4E2D9C7EE4747F...

Energy Delivery Modernization and Operational Efficiency

1.0 CHANGE REQUEST # 1 – 05/15/23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
5/15/23	*Scope Change*	1	$4,410,000	$814,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
5/15/23	Scope Change				+814k
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	3,400,000					
2025	6,970,000					
2026	5,175,000					
2027	3,450,000					
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Energy Delivery Modernization and Operational Efficiency

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Work	Amount
Arcos Enhancements 2022	$37,000
AiDash - Disaster & Disruption Management System (DDMS)	$37,000
Fleetworthy 2023	$48,000
iOffice 2023	$75,000
OATI FERC Order 676-J Functional Modifications	$59,000
Maximo Conversion License 2022	$135,000
Maximo Enhancements 2023	$200,000
Priority Based Control Engineering (PCE) License 2023	$123,000
Service Suite	$100,000
Total Change Request	**$814,000**

Each of the above are described below in detail:

ARCOS – Application $37k. This project required additional investigation into the business processes in order to streamline the new process, reduce manual data import, and remove redundant processes. This has extended the schedule and corresponding budget past initial estimates. In addition, to maintain Avista standards, the database schema needs to be migrated from a 12c to 19c database as part of this project. This additional scope was not available at the charter of this project but now is being required across all Avista systems.

Ai-Dash – Outage Forecasting – $37K. This is an opportunity to create a standardized mechanism for measuring the potential impact of a weather forecast on our electric distribution system. There is a need to have a system that can monitor, alert, and provide a forecast of expected outages and associated restoration times. This tool will monitor and alert Avista stakeholders when potential wide scale events are likely to occur to allow for appropriate planning.

Fleetworthy – Driver Management - $48K. We are currently out of contract with our current provider which has raised their rates, has had a serious data breech, and routinely allows us to be out of Department Of Transportation (DOT) compliance. Fleetworthy offers reduced labor on our users, a better price point than our current provider and improved reporting that will assist Avista in saying in compliance and not being fined.

iOffice – Space Planning - $75K. This is . This is an opportunity to create a standardized mechanism for employee desk locations, move requests, and historical reporting. The The current process is manual and results in reactive decision-making, time, and labor costs due to the lack of space planning tools, processes, and methodologies. As we allow hybrid (partial/full time) which requires us to re-harvest/restack space for individuals or full departments, it is not possible to perform with current staffing capacities. This causes increased labor and rework if not performed with technology.

OATI - $59K. Substantive impacts to Open Access Technology International (OATI) services and systems caused by Federal Energy Regulatory Commission (FERC) Order 676-J will be deployed on Avista's impacted systems. OATI will provide all planning, development, testing, and Production deployments on all impacted systems. OATI will provide all planning, development, testing, and Production deployments on all impacted systems

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Energy Delivery Modernization and Operational Efficiency

Max Conversion – License $135K. This is a new licensing model for Maximo and Avista was required to move to this method by 9/2025. The $1.625M in capital (includes tax) hit in December 2023. The $135K resulted from trailing charges having it land at the end ouf 2023.

Maximo Enhancements – Application $200k. This project is part of the top 20 Enterprise Technology projects at Avista and therefore shares part of the overall product teams operating costs (Enterprise System Calulator). These shared charges allow for our agile teams to level their labor over the top 20 projects to continue operating at a high level.

Priority Based Control Engineering (PCE) - $122K. This software measures utility generation control performance, as adopted by NERC (North American Electric Reliability Corporation).

Service Suite – Application $100,000. This project is part of the top 20 Enterprise Technology projects at Avista and therefore shares part of the overall product teams operating costs (Enterprise System Calulator). These shared charges allow for our agile teams to level their labor over the top 20 projects to continue operating at a high level.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Michael Mudge	BC Owner	DocuSigned by: Mike Mudge 44C0BE3C52404B4...	May-16-2023 | 10:57 AM PDT
Hossein Nikdel	BC Sponsor	DocuSigned by: Hossein Nikdel E4E2D9C7EE4747F...	May-12-2023 | 4:55 PM PDT
Josh DiLuciano	SC Review	DocuSigned by: A3C74874F8564DB...	May-12-2023 | 4:23 PM PDT
Heather Rosentrater	BC Sponser	DocuSigned by: B327AA65D6E64F6...	May-15-2023 | 7:34 AM PDT

Energy Delivery Modernization and Operational Efficiency

1.0 CHANGE REQUEST # 2 – 08/15/23

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
5/15/23	*Scope Change*	1	$4,410,000	$814,000	$514,000	$4,924,000
8/15/23	*Scope Change*	2	$4,924,000	$235,000		
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
5/15/23	Scope Change				+814k
8/15/23	Scope Change				+235k
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	3,400,000					
2025	6,970,000					
2026	5,175,000					
2027	3,450,000					
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Energy Delivery Modernization and Operational Efficiency

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

Work	Amount
Doble Engineering Contract Renewal	$23,000
AldenOne Subscription model	$200,000
CROW Licensing Expansion	$12,000
Total Change Request	**$235,000**

Each of the above are described below in detail:

Doble Engineering Contract Renewal –$23k. This software is used to perform Sweep Frequency Response Analysis (SFRA) testing on transformers. Once the testing is performed the software allows us to analyze the results to help evaluate the current condition of a power transformer. This is to cover the capital portion of the contract renewal that can be capitalized.

AldenOne Subscription Model - $200K. AldenOne provides software used to manage pole attachments. This request is to pay for an unplanned move from the current fee structure for the software to a prepaid subscription model. This lowers the amount of labor involved in managing the current fee method of paying for the AldenOne services while not changing the overall cost.

CROW License Expansion – $12K. This is an unplanned expansion of our Control Room Operator Logging, Reporting, and Notification software (CROW) licensing for Protection Engineering to mitigate a compliance violation with NERC.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date	
Michael Mudge	BC Owner	DocuSigned by: Mike Mudge 44C0BE3C52404B4...	Aug-11-2023	3:22 PM PDT
Hossein Nikdel	BC Sponsor	DocuSigned by: Hossein Nikdel 54E2B9C7EF4747F...	Aug-11-2023	8:12 PM PDT
Josh DiLuciano	SC Review	DocuSigned by: Josh DiLuciano A3C71874F6564DB...	Aug-11-2023	11:59 AM PDT
Heather Rosentrater	BC Sponser	DocuSigned by: B327AA65D6E64F6...	Aug-11-2023	12:07 PM PDT

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Energy Delivery Modernization and Operational Efficiency

1.0 CHANGE REQUEST # 3 – 10/15/23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
06/23	*Scope Change*	1	$4,410,000	$814,000	$514,000	$4,924,000
08/23	*Scope Change*	2	$4,924,000	$235,000	$235,000	$5,159,000
10/23	*Revised Cost*	3	$5,159,000	$728,000		

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
5/15/23	Scope Change				+814k
8/15/23	Scope Change				+235k
10/15/23	Revised Cost				+728k

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	3,400,000					
2025	6,970,000					
2026	5,175,000					
2027	3,450,000					
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Energy Delivery Modernization and Operational Efficiency

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

There are two drivers for the EDMOE CR3. One is related to previous license expense costs, being recategorized as capital, and the other is a reprioritization of resources within Energy Delivery.

Within the Atlas Program, resources have been prioritized to alternative Avista efforts, resulting in a surplus of labor within the Atlas area.

The prioritized efforts also fall with the Energy Delivery area, and the surplus Atlas labor is being applied to the EDMOE business case. An offsetting change request is being submitted for Atlas.

The ESRI Utility Network effort is being deferred to create capacity in the Geographic Information System (GIS) and business teams to support other enterprise initiatives, such as the the ArcMap 10.8.1 upgrade, and the Mobility in the Field (MIF) work. The MIF efforts support the portfolio of gas compliance programs such as Leak Survey and Atmospheric Corrosion.

The ArcMap 10.8.1 version has been prioritized, as it will extend to the life of the current GIS platform from 2026 to 2028. Extending the GIS applications life, known as Avista Facility Management (AFM), reduces timeline risk. AFM is the system of record for spatial electric facilities in Washington and Idaho and gas facility data in Washington, Idaho and Oregon and provides the connectivity model to support GIS engineering and analysis applications. The AFM is a cornerstone to Avista's ability to provide responsive service across its territory.

The list of software license costs, being converted from expense to capital, can be found below.

Description	Vendor		Amount
ABB Mobile Work Management	HITACHI ENERGY USA INC	Maintenance & Support	$ 45,414
Arcos	ARCOS	SaaS	$ 52,291
IBM Passport	Clean Slate Technology Group	Term License	$ 23,692
Itron CGR - AMI	ITRON	Maintenance & Support	$ 39,323
Non-CIP GE EMS Items	GENERAL ELECTRIC INTERNATIONAL	Maintenance & Support	$ 49,297
OATI - Ops	OPEN ACCESS TECHNOLOGY INTL	SaaS	$ 31,102

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Energy Delivery Modernization and Operational Efficiency

PI - Plant Information	OSI Soft	Maintenance & Support	$ 80,240
		License Subtotal	**$321,359**

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Michael Mudge	BC Owner	DocuSigned by: Mike Mudge 44C0BE3C524B4B4...	Oct-13-2023 | 10:22 AM PDT
Hossein Nikdel	BC Sponsor	DocuSigned by: Hossein Nikdel E4F2D9D7EE4747F...	Oct-13-2023 | 10:14 AM PDT
Josh DiLuciano	SC Review	DocuSigned by: Josh DiLuciano A3C71874F6564DB...	Oct-16-2023 | 6:58 AM PDT
Heather Rosentrater	BC Sponser	DocuSigned by: B327AA65D6E64F6...	Oct-14-2023 | 5:03 AM PDT

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Energy Resources Modernization and Operational Efficiency

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Energy Resources Modernization & Operational Efficiency (ERMOE) business case was expected to transfer to plant approximately $2.7M and ended up transferring approximately $3.4M. This equates to approximately $721k more than expected in 2023. This transfer to plant variance in 2023 is due to delayed transfers from 2022. This business case planned to transfer approximately $2.7M to plant in 2022 and ended up transferring approximately $2.0M, with a variance of approximately $708k under-transferred. The following occurred in 2022 that have impacted Transfer to Plant for both 2022 and 2023:

1. 378k - Aurora & Plexos License renewal: There was a timing error related to the journal entry and the entire license purchase posted in January of 2023.
2. 190k - Oracle Primavera Cloud (OPC) Unifier: The Oracle Phase 2 Unifier project did not TTP in 2022 due to the risk associated to the limited testing capacity and availability at the end of the year.
3. In addition, the LIMS Upgrade project saw an increase in planned TTP in 2023 of approximately 116k.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. The following business case change requests and governance documents are attached with further details surrounding the above explanations for item #1:

- ERMOE In Year Business Case Funds Change Request – 2023
- ERMOE BC Governance – January 2023
- Message from Project Accounting regarding Aurora Plexos licenses

For item #2:

- Oracle Phase 2 Unifier Steer Co slides – December 2022

For item #3:

- 09806226 – CR04 (Change Request for LIMS Upgrade project)

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The above lag in transfers-to-plant does not impact indirect offsets that have been calculated for applications such as the Avista Decision Support System or the Nucleus Energy, Trading and Risk Management System projects.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Brian Hoerner
3AE7BA99E1F54CF...

DIRECTOR SIGNATURE:

X DocuSigned by: Hossein Mkdel
E4E2D9C7EE4747F...

Energy Resources Modernization & Operational Efficiency (ERMOE) Technology

1.0 CHANGE REQUEST #1 – 01/23/23

Previous Requests	Requested	Approved
5-Year Plan	$3,072,400	$2,800,000
CR#1	$212,854	

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
01/2023	$355,911	$2,800,000	$212,854	$3,012,854

Type of Change	In-year Update
Primary Reason for Change	Timing Change, Internally Driven
Response needed by	2/15/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

The capital portion of the Aurora and Plexos License renewal (2-year agreement) was forecasted and planned to transpire In December of 2022, for the amount of $377,597. Per the capital licensing process, a Capital Project Request (CPR) and corresponding Charter was submitted, a project number was assigned on 11/17/22, and was provided to IT Finance / Procurement for purchase and coding that same day.

When project actuals for December 2022 were received, only $164,743 posted, which is $212,854 less than our estimate. Upon inquiry to Projects & Fixed Assets Accounting (PFAA) and IT Finance as to the large variance, it appears that the full capital portion did not get posted to the project in December and a distribution correction needed to be made. This was an error related to the journal entry associated with the payment terms and offset liability coding.

Fortunately, this can be corrected, but unfortunately, due to timing, the remainder of the license purchase is now posted in January of 2023, a new budget year. ERMOE had the funds preserved for the purchase to occur in the 2022 budget year but does not have enough funding for the 2023 budget year to absorb these costs. This reduced the Transfer to Plant (TTP) for 2022 and now adds that amount ($212,854) to our forecasted 2023 TTP. This Change Request is to secure the funding necessary to replenish the 2023 unplanned costs associated with the Aurora/Plexos license renewal purchase.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

The license purchase posted in January and ERMOE does not have funding to absorb these costs. This creates a funding concern for the other planned and prioritized projects in the ERMOE Business Case.

Energy Resources Modernization & Operational Efficiency (ERMOE) Technology

1.1.3 Please reference analysis or information that support the problem and attach to this document.

PFA had performed an AP distribution for the invoice of $164,743 moving it out of capital and to the liability account in January 2023 and posting the full amount from the journal entry into January 2023 GL period. These transactions and the history are recorded in the GL.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

O&M was not impacted.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The desire is to make the correction to the 2022 financials, but the timing of the budget closure impacted the ability to make those changes.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The investment is still prudent, this is timing driven.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid, as this is timing driven.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Brian Hoerner	BC Owner	DocuSigned by: Brian Hoerner 3AE7BA99E1F54CF...	
Scott Kinney	BC Sponsor	DocuSigned by: Scott Kinney 50D41B164A3B414...	
	FP&A		

Change Request Form

Project Name: LIMS/WeighWiz/LabWiz Upgrade 2022
Clarity Project ID: PR00014595
Acctg Project #: 09806226
Business Case Name: Energy Resources Modernization & Operational Efficiency
ER/BI: 5019-19W01
Risk or Issue ID: RSK00008655, ISS00000923
Constraint(s): Scope, Schedule, and Funding
Submit Date: 02/09/2023

1 Key Roles & Project Information

Project Sponsor(s):	Hossein Nikdel	**Business Case Owner(s):**	Brian Hoerner
Program Manager:	Leianne Raymond	**Project Manager:**	Ryan Surface
Steering Committee Members:	Greg Wiggins, Tom Dempsey, Walter Roys, Andy Leija, Brian Rask, Brian Hoerner	**Primary Product Owner:**	Keith Bauer
		Other Stakeholders:	Patrick Lutskas, Greg Frohn, Rosalie Todd, Matt Moots, Keith Bauer, Brandon Naccarato, Rob Fitzsimmons

2 Summary of Change(s)

Scope

- A QA review of the current security login/security process for LIMS found that not all logins followed Active directory standards. When the application is upgraded the Security will need to be reviewed and will require some development from the vendor to complete.

Schedule

- In addition to the new scope, there were key vendor and technical resources that were out of office, thus impacting the time for the vendor to finish their testing prior to assisting Avista with the upgrade to Model Office. This was originally forecasted to occur by 1/27/23 and is now planned for 2/16/23.

Budget

- With the additional scope of the current security login/security process, there will be additional costs due to the General Application Development (GAD) labor required to ensure logins for the LIMS application upgrade meets Avista security standards. Any vendor development work would be outside our upgrade costs.
- The LIMS upgrade includes a web interface which is a change from how the application is currently accessed. The Web interface has been demonstrated for Kettle falls but there is a risk that it may not meet all of their requirements. If that comes to fruition, there will be additional work for the application (Citrix virtualized app) set up to revert to the way the application is currently accessed. This risk is being added into the funding for contingency purposes.
- The labor hours originally forecasted were lower than what was needed to complete the current scope and have been adjusted. This includes labor for User Acceptance Testing from the Kettle Falls team and ET labor.

2.1 Business Impact

If this project is not approved and executed, stakeholders will be at risk of system degradation, support, dependability, security vulnerabilities, etc. The indirect costs offset will not be realized and potentially create additional costs to support the application. Customers would be impacted indirectly from the internal inefficiencies, which could result in customer service challenges.

3 Scope Change Details

Use Cases	Existing Deliverables	Changes to Deliverables
1.	Implement the required and approved application version upgrade to all three applications • LIMS • WeighWiz LabWiz	
2.	Upgrade 2 existing LIMS reporting servers (no hardware costs)	
3.	Desktop Application Packaging	Upgrade Logins for LIMS application to meet Avista Security standards.
4.	Application Package Acceptance Testing (PAT)	
5.	Application Testing in Model Office and Production	
6.	Application Testing in Model Office and Production with new Rugged Devices (see Assumptions section 4.1)	
7.	Application Testing in Model Office and Production with new Weigh Stations (see Assumptions section 4.1)	
8.	User Acceptance Testing (UAT)	
9.	Training (Train the Trainer) if necessary	
10.	Network Impact Assessment (NIA)	
11.	Security Impact Assessment (SIA)	
12.	Operational Handoff	

3.1 Where Will Technology Be Deployed

Kettle Falls Generation Station and Mission Data Center

4 Schedule Change Details

Major Milestone Descriptions	Target Completion Dates (MM/YY)	
	Planned Date	Revised Date
Project Initiation – *Actual approval date*	05/22	05/22
Scope approval w/VROMs (Go / No-go decision point) – *Actual approval date*	NA	NA
ETER review and approval actual date – *Actual approval date*	09/22	09/22
PMP / Approval to Execute – *Planned or Actual approval date*	05/22	05/22
Transfer to Plant (TTP) / Go-Live – *Planned date*	2/23	3/23
Forecasted Close Date – *Planned date*	4/23	6/23

5 Compliance and Controls

Area	Required (Y/N)
Compliance Impact Assessment (contact: Jennifer Massey)	*
Business Continuity Plan/Business Impact Assessment (contact: Erin Swearingen) - *Always Required (excluding enhancement packages)*	Y
Reliability Compliance (NERC) (contact: Erin McClatchey)	*
SOX Business Controls Impact Assessment (contact: Krista Johnson)	*

SOX Application Pre and Post Implementation Assessment (contact: Molly Favor)	*
Security Impact Assessment (SIA) (contact: Shanna Pagniano) - *Always Required*	Y
TSA Directive Review (contact: Jennifer Truman)	*
PCI (Payment Card Industry) Compliance Assessment (contact: Shanna Pagniano)	*
Network Impact Assessment (contact: Ignacio Chapa) - *Always Required*	Y

6 Funding Change Details

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Labor:	$89,001	$103,063	$192,064
Non-ET Labor:	$0	$1,000	$1,000
Product:	$0	$0	$0
Professional Services:	$4,600	$1,000	$5,600
Other:	$93	$10,000	$10,093
AFUDC:	$2,573	$1,021	$3,594
Total:	**$96,267**	**$116,084**	**$212,351**

7 FERC Allocation of Project Costs

Accounting Asset Category	Installation *(107600)*		Removal *(108000)*	Total ($)
	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Hardware (FERC Account 391)	$0	$0	$0	**$0**
Communications Equipment (FERC Account 397)	$0	$0	$0	**$0**
Software (FERC Account 303)	$0	$212,351	$0	**$212,351**
Estimated Total Capital Cost:	**$0**	**$212,351**	**$0**	**$212,351**

Energy Resources Modernization and Operational Efficiency (ERMOE) Technology

Business Case Governance & Financial Overview

January 2023

Leianne Raymond / Brian Hoerner

Agenda

- 2022 Business Case Financial Summary
- 2022 Financials by Quarter
- Transfer to Plant (TTP) Forecast
- 2023 Financial Overview
- Five Year Plan – Summary
  Five Year Plan – by Project
- Decision Log
- Q & A

Business Case Financial Summary

Actuals through: 12/31/22

Current or Previous Year? Previous

2022 Business Case Financials

Business Case	CPG Approved Spend	YTD Actual Spend	Forecast Spend	Exp. Annual Spend	Variance	% CPG Apprv. Spent
Energy Resources Modernization &	$2,800,000	$2,376,708	$0	$2,376,708	$423,292	84.88%
Grand Total	**$2,800,000**	**$2,376,708**	**$0**	**$2,376,708**	**$423,292**	**84.88%**

Financials by Quarter - 2022

Current or Previous Year? Previous

Actuals Forecast

2022 Project Actuals/Forecasts as of 1/17/2023

Business Case	Project	Phase	Actual 2022 Q1	Q2	Q3	Q4	Grand Total
Energy Resources Modernizatio..	ADSS Enhancements 2022 Pkg. 2 (5/16/22-12/31/22) - ..	Execution		$271,234	$310,666	$529,450	$1,111,350
	Aurora & PLEXOS License Renewal: 2 years - 09806242	Closing				$164,738	$164,738
	Nucleus Enhancements Package 2022 - 09906980	Execution	$152,619	$210,807	$194,830	$159,835	$718,092
	GPSS Maximo Expansion 2022 - 09907000	Execution	$29,083	$44,332	$41,304	$61,085	$175,804
	Oracle Primavera Phase 2: Unifier - 09806230	Execution		$172	$24,410	$59,643	$84,224
	LIMS/WeighWiz/LabWiz Upgrade 2022 - 09806226	Execution		$11,282	$32,769	$44,751	$88,802
	Stackvision Upgrade 2022 - 09806238	Execution				$16,657	$16,657
	Oracle Primavera Implementation (OPC): Phase 1 - 098..	Complete	$1,895				$1,895
	Nucleus Enhancements Package 2021 - 09906798	Complete	$14,589				$14,589
	GPSS Mobile Solution - Maximo Anywhere 09806019	Complete	($1,365)				($1,365)
	GPSS Maximo Expansion 2021 - 09906800	Complete	$2,583				$2,583
	ABB Sendout System Replacement (Plexos) - 09906887	Complete	($660)				($660)
	Total		$198,743	$537,827	$603,980	$1,036,158	$2,376,708
Grand Total			$198,743	$537,827	$603,980	$1,036,158	$2,376,708

AVISTA

Variances

❖Aurora Plexos Licenses - 2 year annually paid agreement

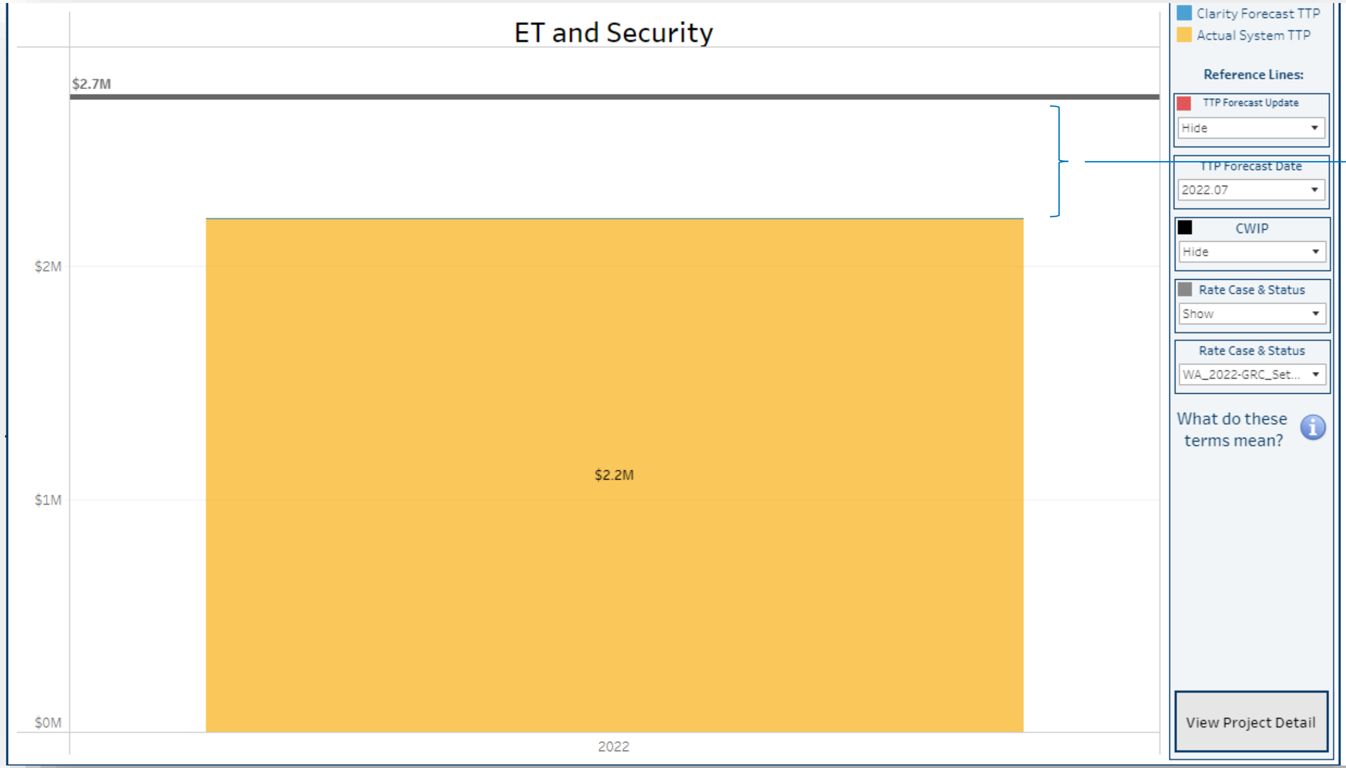
- Aurora Plexos License Agreement - Capital estimate provided (with tax) – $377,597
- Aurora Plexos License Posted Actuals in 2022 = $164,738
- Aurora Plexos License Variance = $212,859
  - Only the 1st year's invoice posted to project, per error with journal entry.
  - It will get corrected this month, but now will hit 2023.

When we have software agreements that are paid on an annual basis for 2 or more years, PA has to create a journal entry to post the full capitalized portion (based on the agreement) to capital project and offset to a liability account. When the annual invoices are paid, they are to coded to the liability account and not the project.

❖OPC Phase 2 Unifier

- Oracle PS and labor estimate higher than actuals
- Oracle invoice posted in January 2023 instead of December

Transfer to Plant (TTP) Forecast



OPC Unifier
LIMS Upgrade
Nuc/GPSS Max/ADSS (overall lower spend)

Project: (All)

Use the project filter to exclude projects from both the table below and the bar chart above.
Hover over the 'Business Function' header and click the '-' to roll-up and the '+' to drill-down

Year (Table): 2022

How to download this data

Business Fu..	ER + Desc	BI + Desc	Project	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ET Subfunction	5019 - Energy Resources Modernizati..	18W02 - Energy Resources ..	ADSS Enhancements 2022 Pkg. 2 (5/..												$1,111,350	$1,111,350
			Stackvision Upgrade 2022 -											$10,121	$6,535	$16,657
			Oracle Primavera Implementation (O..	$700	$1,195											$1,895
		19W01 - Energy Resources Modern & Op Efficiency CDAA	GPSS Maximo Expansion 2022 -												$158,484	$158,484
			Nucleus Enhancements Package 202..	$21,161	$41,958	$89,500	$66,814	$62,420	$81,573	$33,713	$63,467	$97,650	$18,180	$75,173	$66,483	$718,092
			Nucleus Enhancements Package 202..	$174	$14,415											$14,589
			GPSS Mobile Solution - Maximo Any..	$78		$1,517										$1,595
			GPSS Maximo Expansion 2021 - 099..	$183,093	$576											$183,669
			ABB Sendout System Replacement (..	$1,351	($2,010)											($660)
Grand Total				$206,556	$56,134	$91,017	$66,814	$62,420	$81,573	$33,713	$63,467	$97,650	$18,180	$85,294	$1,342,852	$2,205,670

Project Status Reports

Project	Phase	Year of Latest ..	Status Report Update	Key Accomplishments	Upcoming Activities	Budget Status	Schedule Status	Scope Status
Aurora & PLEXOS License Renewal: 2 years - 09806242	Closing	2023						
ADSS Enhancements 2022 Pkg. 2 (5/16/22-12/31/22) - 09806227	Execution	2023	-Time cards for this project shut down in favor of the new 2023 ADSS project.	-TTP accepted -SIA Approved -Release – Hotfix 8.0.1 deployed	-Complete Closing documents -NIA in progress -TFS story 499328			
GPSS Maximo Expansion 2022 - 09907000	Execution	2022	-Time keeping has switched from this 2022 project (09907000) to the 2023 project (09907194)	-Barcoding feature now available for use. -SIA approved -TTP processed -NIA Network Impact assessment filed	-Complete on Closing documents -NIA			
LIMS/WeighWiz/LabWiz Upgrade 2022 - 09806226	Execution	2023	-1.13.23 LIMS core team meeting -1.12.23 Meeting with 3log to review upgrade	-CR 09806226-CR02 approved 10.31.22 -CR 09806226-CR03 approved 12.09.22 -12.1.22 Steerco	-1.25.23 LIMS January steerco -SIA Story 501276 -NIA Story 511534			
Nucleus Enhancements Package 2022 - 09906980	Execution	2021	Update -Time keeping has switched from this 2022 project (09906980) to the 2023 project (09907193) ..	-SIA Approved	-Complete Approval to close documents -NIA			
Oracle Primavera Phase 2: Unifier - 09806230	Execution	2023	-Unifier Admin training	-NIA Approved -SIA Approved -12.15.22 Unifier Steerco	-1.17.23 Steerco for Jan -Complete TTP with new form now that training is completed			
Stackvision Upgrade 2022 - 09806238	Execution	2023	-1.13.23 meeting with Data vendor SRSS	-Upgrade complete, required reporting for 10.22.22 done. -11.10.22 Next steps meeting -SIA approved..	NIA -determine where to extend this project or move remaining work on data delivery to new project			

2023 Financial Forecast

Current or Previous Year? Current

2023 Business Case Financials

Business Case	CPG Approved Spend	YTD Actual Spend	Forecast Spend	Exp. Annual Spend	Variance	% CPG Apprv. Spent
Energy Resources Modernization &	$2,800,000	$0	$2,896,592	$2,896,592	($96,592)	0.00%
Grand Total	**$2,800,000**	**$0**	**$2,896,592**	**$2,896,592**	**($96,592)**	**0.00%**

Current or Previous Year? Current

Actuals Forecast

2023 Project Actuals/Forecasts as of 1/17/2023

			Forecast 2023				
Business Case	Project	Phase	Q1	Q2	Q3	Q4	Grand Total
Energy Resources Modernizatio..	Aurora & PLEXOS License Renewal: 2 years - 09806242	Closing	$2,392				$2,392
	ADSS Expansion 2023 - 09806250	Execution	$408,168	$229,768	$226,775	$205,289	$1,070,001
	GPSS Maximo Expansion 2023 - 09907194	Execution	$18,557	$75,093	$86,584	$69,767	$250,000
	LIMS/WeighWiz/LabWiz Upgrade 2022 - 09806226	Execution	$31,906	$3,455			$35,361
	Nucleus Enhancements Package 2022 - 09906980	Execution	$11,552				$11,552
	Nucleus Expansion 2023 - 09907193	Execution	$228,258	$244,376	$243,566	$233,800	$950,001
	Oracle Primavera Phase 2: Unifier - 09806230	Execution	$92,556				$92,556
	Stackvision Upgrade 2022 - 09806238	Execution	$3,445				$3,445
	GPSS Log Books	Queued				$51,283	$51,283
	Hazardous Waste Tracking (Intelex)	Queued		$30,063	$34,791	$35,147	$100,000
	Matterport Subscription	Queued		$14,912	$25,087		$40,000
	Oracle Primavera Cloud (OPC) - Phase 3	Queued		$57,592	$109,625	$82,783	$250,000
	Stackvision Upgrade 2023 (Q2)	Queued		$16,233	$8,767		$25,000
	Stackvision Upgrade 2023 (Q4)	Queued				$15,000	$15,000
	Total		$796,835	$671,492	$735,195	$693,069	$2,896,592
Grand Total			$796,835	$671,492	$735,195	$693,069	$2,896,592

Five Year Plan (2023-2027)

Year	Requested Amount	CPG Approved Amount	*Requested vs. Approved Variance*	*% of allocation received*	Current Forecast	CPG Approved vs. Forecast Variance	Details
2024	$3,025,000	**$2,800,000**	*$225,000*	*93%*	**$3,668,672**	($868,672)	Added Aurora/Plexos License Renewal / Stackvision Upgrade
2025	$2,940,000	**$2,800,000**	*$140,000*	*95%*	**$2,960,080**	($160,080)	Ignition added and Stackvision Upgrade (large upgrade – Saas?)
2026	$3,395,000	**$3,250,000**	*$145,000*	*96%*	**$3,877,259**	($627,259)	Added Aurora/Plexos License Renewal / Gurobi License Renewal
2027	$3,060,000	**$2,800,000**	*$260,000*	*92%*	**$2,985,000**	($185,000)	
2028							
Total	$15,492,400	**$11,650,000**	*$770,000*	*93%*	**$13,491,012**	**($1,841,012)**	

5 Year Roadmap – 2024

Projects 2023+

Business Case	Project	Goal	2024 Q1	2024 Q2	2024 Q3	2024 Q4	Grand Total
Energy Resources Modernization & Operational Effi	ADSS Expansion Package 2024	Run the Business	$239,900	$340,055	$246,977	$364,068	$1,191,000
	Aurora & PLEXOS License Renewal 2024	Run the Business				$398,954	$398,954
	GPSS Log Books	Run the Business	$226,912	$41,805			$268,717
	GPSS Maximo Expansion 2024	Run the Business	$1,218	$69,255	$95,677	$93,850	$260,000
	Ignition (HMI) Expansion 2024	Run the Business	$6,653	$49,380	$53,724	$75,244	$185,000
	LIMS/WeighWiz/LabWiz Upgrade - 2024	Run the Business		$17,543	$22,457		$40,000
	Nostradamus Upgrade- 2024	Run the Business		$13,625	$26,375		$40,000
	Nucleus Expansion Package 2024	Run the Business	$299,929	$251,178	$214,708	$234,185	$1,000,000
	Oracle Primavera Cloud (OPC) - Phase 4	Grow the Business		$33,364	$110,100	$106,536	$250,000
	Stackvision Upgrade 2024 (Q1)	Run the Business	$13,155	$6,846			$20,000
	Stackvision Upgrade 2024 (Q4)	Run the Business				$15,000	$15,000
	Total		$787,765	$823,052	$770,018	$1,287,837	$3,668,672

5 Year Roadmap – 2025/2026

2025

Business Case	Project	Goal	2025	Grand Total
Energy Resources Modernization & Operational Effi	ADSS Expansion Package 2025	Run the Business	$1,225,500	$1,225,500
	GPSS Maximo Expansion 2025	Run the Business	$269,579	$269,579
	Ignition (HMI) Expansion 2025	Run the Business	$185,000	$185,000
	Nucleus Expansion Package 2025	Run the Business	$1,050,000	$1,050,000
	Oracle Primavera Cloud (OPC) Unifier License Renewal	Run the Business	$100,000	$100,000
	Oracle Primavera Cloud Expansion 2025	Run the Business	$50,000	$50,000
	Stackvision Upgrade 2025	Run the Business	$80,000	$80,000
	Total		$2,960,080	$2,960,080

2026

Business Case	Project	Goal	2026	Grand Total
Energy Resources Modernization & Operational Effi	ADSS Expansion Package 2026	Run the Business	$1,300,000	$1,300,000
	Aurora & PLEXOS License Renewal 2026	Run the Business	$410,923	$410,923
	GPSS Maximo Expansion 2026	Run the Business	$285,000	$285,000
	Gurobi Optimization License Renewal 2026 (5 year)	Run the Business	$441,334	$441,334
	Ignition (HMI) Expansion 2026	Run the Business	$185,000	$185,000
	LIMS/WeighWiz/LabWiz Upgrade - 2026	Run the Business	$70,000	$70,000
	Nostradamus Upgrade- 2026	Run the Business	$60,000	$60,000
	Nucleus Expansion Package 2026	Run the Business	$1,075,000	$1,075,000
	Oracle Primavera Cloud Expansion 2026	Run the Business	$50,000	$50,000
	Total		$3,877,259	$3,877,259

5 Year Roadmap –2027/2028

2027

Projects 2023+

Business Case	Project	Goal	2027	Grand Total
Energy Resources Modernization & Operational Effi	ADSS Expansion Package 2027	Run the Business	$1,350,000	$1,350,000
	GPSS Maximo Expansion 2027	Run the Business	$295,000	$295,000
	Ignition (HMI) Expansion 2027	Run the Business	$190,000	$190,000
	Nucleus Expansion Package 2027	Run the Business	$1,100,000	$1,100,000
	Oracle Primavera Cloud Expansion 2027	Run the Business	$50,000	$50,000
	Total		$2,985,000	$2,985,000

2028

TBD

AVISTA

Decision Log - 2023

Month	Decision	Action	Approval	Date Approved
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				

Q&A

Thank you!

ERMOE Overview

The Energy Resources Business Program supports the application-related technology initiatives for all areas within Energy Resources. These areas include Power Supply, Gas Supply and Generation Production Substation Support (GPSS).

- ERM and Trading
  - Nucleus and Future Replacement
  - ADSS (2022+)
- Fuel Inventory Management
  - WeighWiz
- Gas Forecasting
  - Nostradamus
  - Plexos
- Work Management
  - Maximo for GPSS
  - Oracle Primavera Cloud
- Generation Plant and Substation Ops
  - Wonderware Replacement (HMI-Ignition 2020+)
  - Stackvision
- EIM (2023+)
  - TBD
- Environment & Real Estate
  - TBD

ERMOE Team

Kevin Holland
Director, Energy Supply

Jason Lang
Director, Finance

Bruce Howard
Sr. Director, Env. Affairs

Jacob Reidt
Manager, Project Delivery

Greg Wiggins
Sr. Mgr. Thermal Ops & Maintenance

Energy Resources Governance

Brian Hoerner
Business Case Owner

Brandon Naccarato
Business Technology Analyst

Leianne Raymond
IS/IT Program Manager

Ryan Surface
Project Manager (contracted)

ET Partners for Energy Resources

Oracle Primavera Phase 2: Unifier Steering Committee

Update

December 15th, 2022

Confidential – For Discussion Purposes Only

Agenda

- Dashboard & Financials Review
- Deliverables Status
- Schedule Review
- Risks/Issues Review
- Questions

AVISTA

ET and Security Project Dashboard

Last Update: 12/15/2022 6:01:01 AM

Business Unit	Business Functi...	Business Case	Project Manager	Project	Project Phase	Project Forecas...	Planned Project	Accounting Year	Point in Time
ET	ET Subfuncti...	Energy Reso...	Surface, Ryan	Oracle Prima...	Execution	Include	Planned	2022	12/15/2022

Business Case	Project	Project Number	Phase	LTD Budget	LTD Actuals	YTD Spend	Estimate To Comple..	Estimate At Compl..	Variance
Energy Resources Modernization & O..	Oracle Primavera Phase 2: Unifier - 09806230	09806230	Execution	$250,000	$68,125	$68,125	$172,064	$240,188	$9,812
	Total			$250,000	$68,125	$68,125	$172,064	$240,188	$9,812
Grand Total				$250,000	$68,125	$68,125	$172,064	$240,188	$9,812

Breakdown

Project Financials

	Actual	Forecast	Total
AFUDC	$504	$1,500	$2,004
ET Labor	$18,671	$36,748	$55,418
Non-ET Labor	$3,464	$3,059	$6,523
Other	$56	$757	$813
Product	$14,606	$0	$14,606
Prof Services	$30,825	$130,000	$160,825
Totals	$68,125	$172,064	$240,188

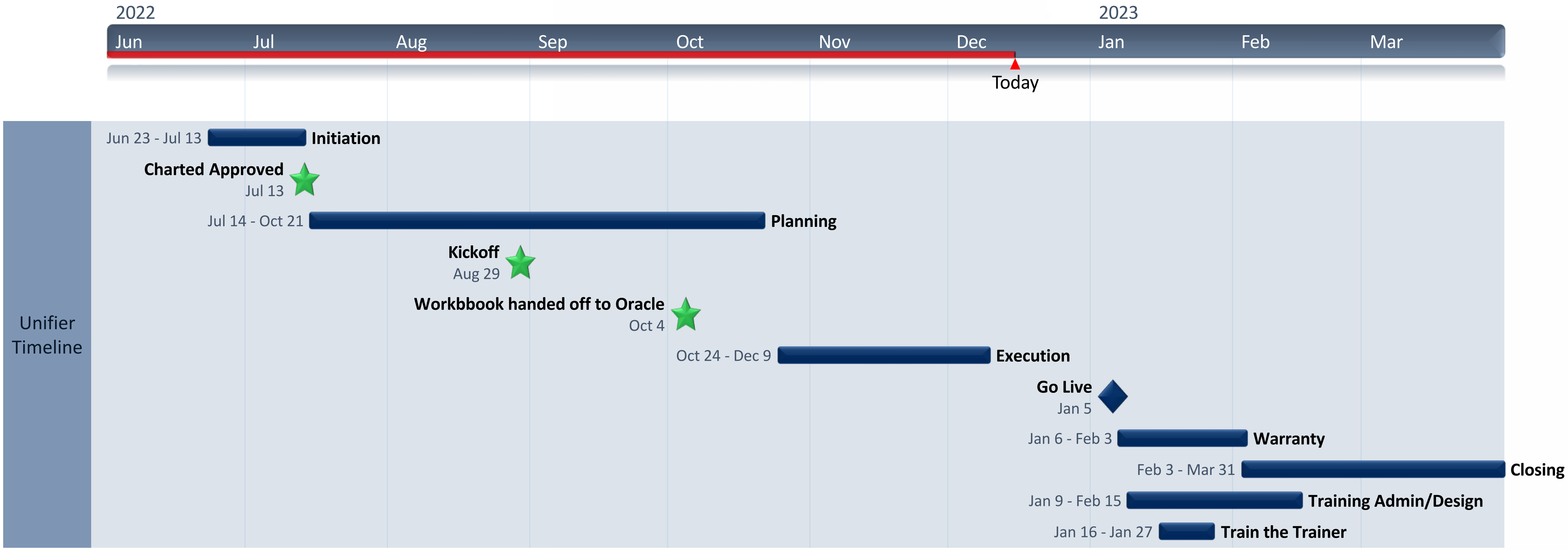
Project	Project Manager	Phase	Latest TTP Date	Status Report Update	Key Accomplishments	Upcoming Activities	Budget Status	Schedule Status	Scope Status
Oracle Primavera Phase 2: Unifier - 09806230	Surface, Ryan	Execution	12/15/2022	-12.8.22 SSO issues for the admin resolved -12.6.22 SSO meeting with Oracle to work on issue 12.7.22 Meeting with Oracle on Cost breakdown Structure.	-9.20.22 Oracle Unifier initial Workbook session with Oracle and the GPSS team -10.17.22 Oracle Primavera Phase 2 - Unifier Stee..	-SIA Story 521227 -NIA Story 524240 -12.14.22 Touch base with Oracle on Go li..			

AVISTA

Oracle Primavera Phase 2: Unifier– Project Scope/Deliverables

- Primavera Unifier Licenses (3-Year term) (Purchased)
- Implementation and Testing of Oracle Primavera Unifier solution
  - Workbook for Oracle configuration (completed 10.4.22)
  - Initial walk through with Oracle (Completed 10.18.22)
- User Acceptance Testing (Completed 12.15.22, verification of changes 12.29.22)
- Go Live (1.05.23)
- Training (Train the trainer and admin training to take place in early 2023)
- Network Impact Assessment (NIA in progress)
- Security Impact Assessment (SIA nearly complete)
- 30-day post-implementation warranty
- Operational Handoff

Oracle Primavera Phase 2: Unifier Timeline



Oracle Primavera Phase 2: Unifier– Risks

Rank	RISKS/ISSUES	Probability	Impact	Impacted Areas	Mitigation Strategy
1	**Risk –** Vendor schedule aligns with Avista team	**LOW**	**HIGH**	Resource, Schedule	Work with Oracle and PM AJ Erdman resource availability. AJ is aware of our timeline.
2	**Risk** - Resource Constraints (internally and externally)	**LOW**	**HIGH**	Resource, Schedule	Working closely with the Oracle team, AJ Erdman, and the GPSS team. Amanda Hester to ensure we have the resources available to keep to our schedule.
3	**Risk** - A09 budget approval	**LOW**	**LOW**	Schedule	Per Brian H we are good in A09 for the initial planned licenses/Users.

Questions?

Thank you for your support!

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Enterprise & Control Network Infrastructure (ECNI)

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Technology investments under the Enterprise and Control Network Infrastructure business case are needed to expand and maintain network assets for Avista's safety, control, customer-facing, and back-office systems. This is in support of system reliability and business productivity throughout our service territory, ensuring our ability to appropriately respond to the needs of our customers.

For the tracking year of 2023, the Enterprise & Control Network Infrastructure business case planned to transfer-to-plant $0 in project work, while actually transferring $736,619. This resulted in an over-transfer amount because this business had been expected to sunset in 2022.

Nine projects had to be completed and transferred to plant after the planned end to the business case. Projects started in 2022 or prior years were hampered with product lead times that extended project schedules out 8-12 months or longer than originally planned during business case planning activities.

The end result is work anticipated to be completed by end of year 2022 pushed into 2023. Eight projects had trailing costs that had a net value of ($44,592) due to accounting reversals. The Pound Lane to Clarkston Fiber project transferred to plant $781,212 in November resulting in the net transfer to plant for 2023 of $736,619.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. The following business case change requests and governance documents are attached with further details surrounding the above explanations.

- Change request dated September 2023 – Requested funds to cover work pushed from 2022 into 2023

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The above lag in transfers-to-plant does not impact indirect offsets that have been calculated for applications such as the Avista Decision Support System or the Nucleus Energy, Trading and Risk Management System projects.

This business case was due to sunset in 2022. There are not any changes to the indirect offsets that would be calculated for this business case based on the over transfer amount listed above.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Shawna Kiesbuy
3CD905A81B984C3...

DIRECTOR SIGNATURE:

X DocuSigned by: Alexis Alexander
EA27BABA767F467...

1.0 CHANGE REQUEST #01 – 09/2023

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
9/20/2023	Revised Cost	01	$0	$175,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
9/20/2023	Revised Cost			$ 964,347	$726,536
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Enterprise Control and Network Infrastructure (ECNI) business case is an older business case originally set to close 2022. Its closure was aligned with the creation of three new business cases in 2022 to bring more clarity to the project work taking place in the business case. The new businesses include Control & Safety Network Infrastructure, Enterprise Network Infrastructure, and Network Backbone Infrastructure.

In late 2022, due to resource constraints and communication equipment lead times delays, nine ECNI project schedules were pushed into 2023. Currently, only two of the projects remain open with closing dates planned by the end of October 2023. Since the work in 2023 was not planned as part of the yearly budget planning process, this business case has no approved budget for 2023. To align dollars to this, spend, this change request is asking for $175,000 to cover the work that carried over into 2023 and will complete by the end of the year.

It has been known since late 2022 that work in the ECNI business case would carry over into 2023 and funds from another Network business case would be used to cover the actual spend. To that end, a change request has been submitted for the Control and Safety Network Infrastructure (CSNI) business case to release funds to offset the request being made for ECNI. The plan to have funds available in another Network business case to cover the actual spend in ECNI had been discussed and agreed upon with F&PA early in 2023. No alternatives have been considered.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Sep-12-2023 | 11:05 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Sep-12-2023 | 3:50 PM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Enterprise Security Systems

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Enterprise Security Systems business case addresses cybersecurity threats. This is in response to federal agencies overseeing the reliability of electrical and gas infrastructure are increasing their call for utilities like Avista to step up their requirements around security best practices to mitigate eminent risk.

The Enterprise Security Systems (ESS) business case was expected to transfer to plant approximately $1.1M and instead transferred approximately $4.5M. This equates to approximately $3.4M more than expected in 2023. Enterprise level security tools and their implementation experienced a significant rise in cost. The most significant cause of the variance was the result of five projects refreshing the organization's critical firewalls. Refreshing these corporate and operational technology firewalls was not planned in the original rate case filing. One mitigation tactic to manage these vendor increases is to extend renewals from 3 to 5 years, which may result in greater vendor discounts and therefore benefits Avista and its customers. Most notably, some of our firewall replacements moved from 3 to 5 years and thus required an increase of our existing capital allocation, which was flat for the past 5 years. The increased amount allowed the ongoing cyber security projects to continue, keeping Avista's networks secure.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The CPG funds change requests are attached detailing the requested allocation increases. The following Business Case Change requests account for approx. $1.4M of the total transfer to plant variance.

- ES_Funds_Change_Request_7-2023.pdf - $1.1M for corporate firewall purchases
- ES_Funds_Change_Request_8-2023.pdf - $150k for professional services support for firewall implementation
- ES_Funds_Change_Request_9-2023.pdf - $235k for operational technology firewall purchases

The remaining variance is due to projects in 2022 carrying over into 2023, due to supply chain and resource constraints.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revised offsets associated with this change.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: DIRECTOR SIGNATURE:

DocuSigned by:
6456C8EEF402467...

DocuSigned by:
Clay Storey
B70F95F7961D4B6...

Enterprise Security

1.0 CHANGE REQUEST #2 – 7/13/2023

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
7/13/2023	*Revised Cost*	2	$2,636,205	$1,100,000		
02/2023	*Scope Change*	1	$2,160,000	$ 476,205	$476,205	$2,636,205

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
7/13/2023	Scope Change	N/A	N/A	$3,400,000	$4,400,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	2,000,000	$0	N/A	N/A	$2,860,000	$2,860,000
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Enterprise Security

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

This business case supports the funding of Avista's cyber security projects. Enterprise level security tools and their implementation have seen a significant rise in cost. One mitigation tactic to manage these vendor increases is to extend renewals from 3 to 5 years, which result in greater discounts and benefit Avista and its customers. Most notably, our firewalls replacements are moving from 3 to 5 years and thus have put pressure on the existing allocation, which has been flat for the past 5 years. As a result, the business case is at risk of going over budget by the end of July. The requested amount will allow the ongoing cyber security projects to continue, keeping Avista's network secure.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Andy Leija	BC Owner	DocuSigned by: [signature]	Jul-13-2023 | 3:40 PM PDT
Clay Storey	BC Sponsor	DocuSigned by: Clay Storey B70F95F7961D4B6...	Jul-13-2023 | 3:56 PM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Enterprise Security

1.0 CHANGE REQUEST #2 – 8/10/2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
08/2023	*Revised Cost*	3	$3,186,205	$150,000		$3,336,205
07/2023	Revised Cost	2	$2,636,205	$1,100,000	$550,000	$3,186,205
02/2023	*Scope Change*	1	$2,160,000	$476,205	$476,205	$2,636,205

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
8/2023	Revised Cost	N/A	N/A	$3,400,000	$4,400,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	2,000,000	$0	N/A	N/A	$2,860,000	$2,860,000
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

This business case supports the funding of Avista's cyber security projects. Enterprise level security tools and their implementation have seen a significant rise in cost. One mitigation tactic to manage these vendor increases is to extend renewals from 3 to 5 years, which result in greater discounts and benefit Avista and its customers. Most notably, our firewalls replacements are moving from 3 to 5 years and thus have put pressure on the existing allocation, which has been flat for the past 5 years. The requested amount will allow the ongoing cyber security projects to continue, keeping Avista's network secure.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Andy Leija	BC Owner	DocuSigned by: 8456C8EEF402467...	Aug-11-2023 | 3:19 PM PDT
Clay Storey	BC Sponsor	DocuSigned by: Clay Storey B70F95F7961D4B6...	Aug-11-2023 | 3:59 PM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Enterprise Security

1.0 CHANGE REQUEST #4 – SEPTEMBER 14, 2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
09/2023	*Scope Change*	4	$3,186,205	$235,000		
08/2023	Revised Cost	3	$3,186,205	$150,000		
07/2023	Revised Cost	2	$2,636,205	$1,100,000	$550,000	$3,186,205
02/2023	*Scope Change*	1	$2,160,000	$476,205	$476,205	$2,636,205

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	**Request Type**	**Budgeted Savings /Offsets[1]**	**Revised Savings /Offsets**	**Currently Planned TTP[2]**	**Revised TTP**
09/2023	Scope Change	N/A	N/A	$3,400,000	$4,400,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	**Budgeted Approved Amount[3]**	**Updated Funding Anticipated as a result of request**	**Budgeted Benefits /Offsets[4]**	**Revised Benefits /Offsets**	**Budgeted TTP[5]**	**Revised TTP**
2024	2,000,000	$0	N/A	N/A	$2,860,000	$2,860,000
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The SCADA External FW Refresh project, under the SCADA – SOO and BuCC Business Case, was unable to implement (4) four purchased firewalls as expected due to inoperability challenges with remote SCADA field devices. Returning the firewalls to the vendor is not an option, as they do not issue credits. These firewalls can be implemented in Avista's other environments, thereby making them used and useful by December 2023. However, there is no funding to implement them in 2023 under the Enterprise Security Business Case. Therefore, this is a request in the amount of $235k to cover a corresponding release from the SCADA – SOO and BuCC Business Case, representing the equipment and licensing purchase of the four firewalls.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Andy Leija	BC Owner	DocuSigned by: 6456C8EEF402467...	Sep-15-2023 | 10:18 AM PDT
Clay Storey	BC Sponsor	DocuSigned by: Clay Storey B70F95F7961D4B6...	Sep-15-2023 | 10:49 AM PDT

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

ET Modernization and Operational Efficiency

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Enterprise Technology Modernization and Operational Efficiency business case was expected to transfer-to-plant approximately $2M in 2023 and ended up transferring approximately $3.78M, resulting in an overstated transfer to plant of 1.78M. The primary reasons for this overage are the following:

- 400k in planned transfer to plant for 2022 did not occur, instead these projects completed in 2023
    - This includes license renewals of Acrobat (162K) and Tableau (123k).
    - Cognos Upgrade project (115k).
- A unplanned purchase of Splunk licenses in order to take advantage of future discounts. This cost was 135k.
- An unplanned purchase of Cognos Licenses totaling 460k. This resulted in an overall cost reduction of 30% over 5 years.
- The unplanned Vuetify Upgrade project added 140k, justification for this project is included in supplemental documentation.
- The following planned projects saw an increase in cost, justification for these costs is included in supplemental documentation:
    - Azure DevOps Upgrade70k
    - Cognos upgrade 160k
    - DAAP Expansion – 215k
    - BI / ETL Expansion – 128k

PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The following supplemental emails and documents supported the Cognos, Acrobat and Tableau License Purchases:

- 2022 ETMOE Budget Update email
- Reduction Opportunity – Cognos Licensing email and attachments
- 2022 Capital Licensing Summary email – Acrobat licenses
- 01-2023 ETMOE Governance Steering Committee powerpoint

The Following supported the purchase of Splunk licenses:

- 2023-06 ETMOE Governance Steering Committee powerpoint

The following supported the unplanned Vuetify Upgrade project and increase in costs for DAAP Expansion, BI / ETL Expansion, Azure DevOps and Cognos Upgrades:

- Charter – PMP Vuetify Upgrade
- CR01 DAAP Expansion 2023 - 0907185
- CR01 09907165 – Azure DevOps Upgrade
- CR03 – CR 05 – Cognos Upgrade
- BI ETL Pkg 2 Change Request JB v2

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revisions to Offsets.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Karen Schuh
0D892330AD2944F...

DIRECTOR SIGNATURE:

X DocuSigned by: Hossein Mkdel
E4E2D9C7EE4747F...

Change Request Form

Project Name:	BI / ETL Expansion 2023 Pkg. #2
Clarity Project ID:	00017814
Acctg Project #:	09907189
Business Case Name:	Enterprise Technology Modernization & Operational Efficiency (ETMOE) BI
ER/BI:	5026-26W01
Risk or Issue ID:	RSK00009051, RSK00009053
Constraint(s):	Scope and Funding
Submit Date:	09/12/2023

1 Key Roles & Project Information

Project Sponsor(s):	Hossein Nikdel	**Business Case Owner(s):**	Karen Schuh
Program Manager:	Elisabeth Sibulsky	**Project Manager:**	Jamie Boyd
Steering Committee Members:	Michael Mudge, Karen Schuh, Nolan Steiner, Hossein Nikdel	**Primary Product Owner:**	Jason Humbert
		Other Stakeholders:	Leianne Raymond, Jason Pegg, Jason Humbert, Stacey Martin

2 Summary of Change(s)

Scope Request:

This is a request to add the following scope to the project

- Creation of data sets for the following:
  - Customer Load Profiles
  - Peak Time Rebates
  - Clean Energy Transformation Act (CETA) Customer Benefit Indicators
  - Time of Use (TOU) Rates Marketing Propensities
  - Time of Use (TOU) Follow Up; Usage Comparison between Rate Schedules
  - Power Supply/ Datasets for Various needs
  - Small Businesses – Abnormal Usage Identification
  - Propensities for Program Participation
  - Propensities for Rebates
  - EV Customer Identification
  - Fleet -- Vehicle Utilization
  - Fleet – Idle Times and Fuel Expense
  - Overload Transformers
  - 811 Model – Work Type Fuzzy Matching Model

- Actian Data Connect is one of Avista's data integration platforms that enables the Extract, Transform and Load (ETL) processes. Actian Data Connect is now 'end of life' and currently out of support, which has accelerated the requirement to convert multiple processes into a different solution. Actian Data Conversions for the following processes have been added to the scope:
  - Active_Directory
  - AD_Valumation_Extract
  - AD_SCCM_Project
  - Mandarin_Library
  - The new conversions will provide better automation opportunities and minimize future data breakdowns.

- Creation of new Human Resources Data Warehouse that will increase reliability of Human Resources Data Integrations and speed up development of future use cases for Human Resources Data.

Funding Request:
This is a request to add $145,326 in funding to increase the budget from $75,000 to $220,326 to:
- Labor to create 10 data sets that will enhance and support data elements across the company.
- Labor to convert new Actian Integrations from Actian Data Connect that are currently end of life and out of support.
- Labor to create new Human Resources Data Warehouse that will support conversion of Actian Integrations that are 'end of life' and currently out of support.

2.1 Business Impact

If progress is halted due to funding, Avista will not benefit from updated framework and automated processes provided by data set creation and Actian conversions. Data sets and other work connected to Avista's Business Intelligence (BI) tools, Cognos and Tableau, as well as Avista's Extract, Transform and Load (ETL) tools, Feature Manipulation Engine and Alation, will be affected and result in a loss in productivity.

If progress is halted due to funding, we will be unable to complete the remaining Actian conversions and unable to create data sets with multiple use cases across the company. A failure to complete remaining Actian conversions would impact Employee Attribute Data that has multiple system dependencies across the organization.

3 Scope Change Details

Existing Deliverables	Changes to Deliverables
Implement prioritized and approved BI/ETL Data Sets	Creation of data sets for the following: - Customer Load Profiles - Peak Time Rebates - Clean Energy Transformation Act (CETA) Customer Benefit Indicators - Time of Use Rates Marketing Propensities - Time of Use (TOU) Follow Up; Usage Comparison between Rate Schedules - Power Supply/ Datasets for Various needs - Small Businesses – Abnormal Usage Identification - Propensities for Program Participation - Propensities for Rebates - EV Customer Identification - Fleet -- Vehicle Utilization - Fleet – Idle Times and Fuel Expense - Overload Transformers - 811 Model – Work Type Fuzzy Matching Model

	Addition of the following Actian Data Conversions: - Active_Directory - AD_Valumation_Extract - AD_SCCM_Project - Mandarin_Library
Data Set Testing in Model Office and Production (if applicable)	
Security Impact Assessment (SIA)	
Network Impact Assessment (NIA)	
User Acceptance Testing (UAT)	
30 Day Warranty	

3.1 Where Will Technology Be Deployed

4 Technology will be deployed in the Avista Data Center.

5 Compliance and Controls Requirements

Compliance Area	Required (Yes, No, *)
Compliance Impact Assessment	No
Business Continuity Plan/Business Impact Assessment	No
Reliability and Cyber Compliance (NERC)	No
SOX Business Controls Impact Assessment	No
SOX Application Pre and Post Implementation Assessment	Yes
Security Impact Assessment (SIA)	Yes
Payment Card Industry (PCI) Compliance Assessment	No
Network Impact Assessment (NIA)	Yes
FERC/Dam Safety and Cyber Security	No
Outage Coordination	No
Operational Licensing	No
Permits	No
Full Network Model Impact Assessment	No

**Will be assessed during the Planning Phase*

6 Funding Change Details

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Labor:	$73,410	$140,465	$213,875
Non-ET Labor:	$0	$0	$0
Product:	$0	$0	$0
Professional Services:	$0	$0	$0
Other:	$681	$0	$681
AFUDC:	$909	$4,861	$5,770
Total:	**$75,000**	**$145,326**	**$220,326**

Change Request Form

7 FERC Allocation of Project Costs

Accounting Asset Category	Installation *(107600)*		Removal *(108000)*	Total ($)
	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Hardware (FERC Account 391)	$0	$0	$0	**$0**
Communications Equipment (FERC Account 397)	$0	$0	$0	**$0**
Software (FERC Account 303)	$0	$220,326	$0	**$220,326**
Estimated Total Capital Cost:	**$0**	**$220,326**	**$0**	**$220,326**

Project Initiation Charter

Project Name:	Vuetify Upgrade
Accounting Project #	09907209
Clarity/Maximo/Work Order#:	PR00017412
Business Case Name:	ET Modernization and Operational Efficiency
ER-BI:	5026-26W01
Submit Date:	1/31/2023

1 Key Roles & Project Information

Project Sponsor(s):	Hossein Nikdel	**Business Case Owner:**	Karen Schuh
Program Manager:	Leianne Raymond	**Project Manager:**	Amira Djulovic
Solution Architect	Rob Fitzsimmons	**Primary Product Owner:**	Keith Bauer
Advisory Committee:	ETMOE Governance (Jim Kensok, Hossein Nikdel, Jim Corder, Clay Storey, Nolan Steiner)	**Stakeholders:**	Patrick Everitt (HR), Facilities (Annie Lundy), GIS Team (Ron Riel)
Steering Committee Members:	GAD Team Steering Committee		

2 Project Overview

2.1 Business Need & Project Objectives

Vuetify is a coding framework that contains components which enable developers to create concise modules to meet specific business needs through the creation of web applications. Currently the framework provides modules for the Resource Hub, Change of Status, Background Experience, Pacesetters, Position Requests, Mobile Order Monitor, and the Globalscape Portal.

The version of .Net that currently running is at the end of its lifecycle and there are regular upgrades that are required for this application in order to preserve the framework that is needed to ensure these critical modules are supported, compatible, reliable and secure. In addition, we will be able to take advantage of new functionality that the upgrade provides.

2.2 Strategic Focus Area

Primary Focus Area for project (select one):		
☐	**Our Customers**	▪ Mature our customer experience, both internal & external ▪ Partner with communities & customers to support economic recovery & growth ▪ Address evolving customer needs by offering products, services, & energy efficiency solutions
☐	**Our People**	▪ Mature safety systems to promote learning & reduce risks ▪ Invest in our people supporting their development, resiliency & well-being ▪ Strengthen equity, inclusion & diversity within systems, practices & behaviors
☒	**Perform**	▪ Continuously improve generation/delivery of safe, reliable, clean, affordable electric & natural gas service ▪ Achieve stated financial objectives through focused cost management, timely rate recovery, business transformation, & unregulated business development
☐	**Invent**	▪ Advance our electric & natural gas clean energy strategy with equity, affordability, & reliability ▪ Cultivate innovation skills & interest to support transformation & growth ▪ Pursue a reimagined utility of the future with optimized bi-directional grid & new rate-making paradigm

2.3 Metrics Demonstrating Need & Benefit

This upgrade is critical to ensure that the tools used to meet business and compliance requirements perform safely and dependably. In addition, upgrades introduce improvements, enhancements, and new features which typically result in reduced costs, less downtime, increased efficiency, and security protection.
Avista Customers benefit from safe and reliable technology due to risk mitigation and efficiency gains, resulting in improved customer service.

2.4 Measures to Determine Project Success

As this is an upgrade, the system will be expected to perform and function the same or better than it did prior to the upgrade. In addition, all processes and features must be available and useable as they were prior. With proper testing, all defects should be resolved preceding production, and users will be prepared for the downtime and new features through proper change management and training. Projects and corresponding deliverables should not be delayed as a result of this upgrade.
Project metrics are also measured through the Enterprise Technology (ET) PMO Project Management Office (PMO) through an integrated measurement of the success of the technology to align with Avista's corporate strategy and Focus Areas.

2.5 Impact if Not Approved

If this is not approved, we will not be able to preserve the framework that is needed to ensure these critical modules are supported, compatible, reliable and secure. In addition, we will be able to take advantage of new functionality that the upgrade provides. It will also risk other incompatibility or support issues that could cause additional compliance concerns, as well as a loss in productivity.

2.6 High Level Project Requirements

	Deliverables
1.	Upgrade of Vuetify framework
2.	User Acceptance Testing (UAT)
3.	Security Impact Assessment (SIA)
4.	Application Packaging
5.	Package Acceptance Testing (PAT)
6.	Network Impact Assessment (NIA)
7.	30 Day Post Implementation Warranty
8.	Operational Handoff

2.7 What Will Not Be Delivered

	Description	Reason for being out of scope
1.	Enhancements to the specific modules	This package is intended for required upgrades.

2.8 Location of Work

Avista's Mission Data Center

2.9 Stakeholder/Resource Requirements

Enterprise Technology			
Applications (IS)		*Infrastructure (IT)*	
☒	GIS Team	☐	Cloud Architecture
☐	Web Team	☐	Central Systems Engineering
☒	Gen. Application Development Team	☐	Distributed Systems Engineering
☐	CC&B/MDM Team	☐	Communications Systems Engineering
☐	Maximo Team	☒	Network Systems Engineering
☐	Oracle Financials (EBS) /Power Plan Team	☒	Security Systems Engineering
☐	Data Team	☐	IT for Facilities (ITFAC)
☐	Customer Experience Platform (CXP)Team	☐	Enterprise Business Continuity

☐	Integration Team	☐	Disaster Recovery
☐	Avista Decision Support System (ADSS)	*Technology Services*	
☐	Nucleus Team	☐	Technology Service Center
☐	Dev Ops / QA & Release Management	☐	Deployment Services
IS/IT Finance		☒	Packaging
☐	IS/IT Finance Manager	*Project Management Office (PMO)*	
☐	IS/IT Finance Procurement	☒	Program Management
☐	Software Asset Management (Licensing)	☒	Project Management

3 Project Major Milestones

Description	Anticipated or Actual Completion (MM/YYYY)
Business Case Justification Narrative Approved	07/2022
Initiation	
• Phase Gate 1/2 - Project Charter/PMP Approved	02/2023
Execution	
• Phase Gate 3 - Transfer to Plant (TTP) Date	7/2023
• Release to Operations	7/2023
Closeout	
• Phase Gate 4 - Approval to Close	08/2023

4 Assumptions, Risks, Constraints, Dependencies and Considerations

4.1 Assumptions

The following assumptions have been made:

a) Impact to system modules will be minimal

4.2 Risks

- Resource capacity and availability
- Project Priority

4.3 Constraints

- Resource capacity and availability
- Project Priority

4.4 Dependencies

- Budget (Funding)
- Resource Capacity

4.5 Compliance and Controls Requirements

Compliance Area	Required (Yes, No, *)
Compliance Impact Assessment	*
Business Continuity Plan/Business Impact Assessment	*
Reliability Compliance (NERC)	No
SOX Business Controls Impact Assessment	No
SOX Application Pre and Post Implementation Assessment	No
Security Impact Assessment (SIA)	Yes

Payment Card Industry (PCI) Compliance Assessment	No
Network Impact Assessment (NIA)	Yes
FERC/Dam Safety	No
Outage Coordination	No
Operational Licensing	No
Permits	No
Full Network Model Impact Assessment	No

**Will be assessed during the Planning Phase*

4.6 Health, Safety, Security and Environmental (HSSE)

Health, Safety. Security, Environmental (HSSE) Area	Required (Yes, No, *)
Host Employer Safety Information Transfer (HESIT)	No
Environmental	No
Industrial Safety	No
Occupational Health	No
Permitting	No
Licensing	No
Security	No

**Will be assessed during the Planning Phase*

5 Project Cost Estimates

5.1 Project Cost Estimates

Accounting Capital Asset Categories	FERC #	Task #	Design & Engineering	Execution & Installation		Removal	Total ($)
			Labor and Other ($)	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Software	303100	107632	$0	$0	$50,000	$0	**$50,000**
		Total	**$0**	**$0**	**$50,000**	**$0**	**$50,000**

5.2 Financial Operational Impact

O&M Category	Org Code Impacted	Org Manager Approval?	O&M Impact (within project)	Ongoing O&M Impact (post project)					Total
			Estimated Cost ($)	Year 1 ($)	Year 2 ($)	Year 3 ($)	Year 4 ($)	Year 5 ($)	
Licensing			$0	$0	$0	$0	$0	$0	$0
			$0	$0	$0	$0	$0	$0	$0
		Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

6 Project Governance and Reporting

The purpose of these procedures is to provide effective mechanisms to control the scope of the project, manage issues and risks, and monitor progress. Change Control will be managed within the Clarity Project and Portfolio Management System. Below are the steering committee decisions regarding change control for this project:

6.1 Approval Authority

The project manager works closely with all stakeholders to ensure risk is mitigated and contingency plans are created and delivered. All stakeholders can identify a risk and offer a solution(s) for mitigation. Stakeholders can also recommend and develop contingency plans. Meetings are held to discuss risks, mitigation, and contingency recommendations. The project manager and product owner work closely with the business partners, solution architects, developers and engineers on all risk identification, mitigation, and the development of contingency plans. Delivery of risk assessment and contingency planning is a responsibility of the project manager, with input from the delivery managers/business case owners. Based on the severity of the risk, the contingency plan can be approved by the product owner, project manager, or delivery manager/business case owner, with ultimate approval, if needed, from the steering committee. The solution architect, developers and engineers have the authority to implement plans and recommendations approved by the delivery managers/business case owners, product owner (if applicable), project manager and steering committee.

6.2 Specific types of risks, issues, and changes that must have steering committee approval before action can be taken.

Steering Committee members are invaluable to the project and will provide approval on scope, schedule, and budget related changes. Additionally, they will provide approval on issues and risks pertaining to project deliverables outlined in this document, which also typically have an impact on the scope, schedule, or budget of a project. Steering Committee members will also provide approval on Change Requests, Go-Live, and the Approval to Close document.

Change Request Form

Project Name: Azure DevOps Upgrade 2022
Clarity Project ID: PR00017766
Acctg Project #: 09907165
Business Case Name: Enterprise Technology Modernization & Operational Efficiency
ER/BI: 5026/26W01
Risk or Issue ID: RSK00008702, RSK00008708
Constraint(s): Scope, Schedule, Funding
Submit Date: 03/21/2023

1 Key Roles & Project Information

Project Sponsor(s):	Hossein Nikdel	Business Case Owner(s):	Karen Schuh
Program Manager:	Leianne Raymond	Project Manager:	Jacob Weishaar
Steering Committee Members:	Karen Schuh, Mike Mudge, Graham Smith, Brian Hoerner	Primary Product Owner:	Keith Bauer
		Other Stakeholders:	Shane Sullivan, ET Product Owners

2 Summary of Change(s)

Scope: Microsoft has released the new 2022 version of Azure DevOps Server and the Steering Committee has determined that upgrading to the new version (versus the 2020 version) will provide more long-term benefits related to security, performance, reliability, maintenance, cost effective support, and potential labor savings. The decision to proceed with the 2022 version upgrade to the Azure DevOps Server will require upgrades the Application Servers and the Database Servers.

Schedule: The upgrade to the Azure DevOps Server 2022 will require additional time to perform the upgrade of the application and database servers. The Go-Live and Close dates will be impacted by the new scope and has been realigned with the current Integrated Release Schedule. The Go-Live/Transfer to Plant date has moved from 03/23 to 06/23 and the forecasted Close date has moved from 04/23 to 10/23.

Budget: The addition of the new scope and change to the schedule will require increased funding for internal labor, Professional Services, and AFUDC (Allowance for Funds Used During Construction). The total request for this change is an increase of $78,869.

2.1 Business Impact

If this change request is not approved, Stakeholders will not benefit from enhanced system security, performance, dependability, maintenance, cost effective support, and potential labor savings. Avista Customers will not benefit from safe and reliable technology due to the lack of risk mitigation and efficiency gains, resulting in decreased customer service.

3 Scope Change Details

Existing Deliverables	Changes to Deliverables
Upgrade Application Servers to Windows Server 2016	Upgrade Application Servers to Windows Server 2020
Upgrade SQL Database Servers to SQL Server 2016	Upgrade SQL Database Servers to SQL Server 2020
Upgrade Application Version to Azure DevOps Server 2020	Upgrade Application Version to Azure DevOps Server 2022
Integrate on-premise Power BI with Azure DevOps Server 2020	Integrate on-premise Power BI with Azure DevOps Server 2022
Recreate test progress SSRS report in Power BI	

Cloud migration analysis	
Commercial Application Licenses (CAL)	
User Acceptance Testing (UAT)	
Network Impact Assessment (NIA)	
Security Impact Assessment (SIA)	
30-day warranty	

3.1 Where Will Technology Be Deployed
Avista Data Center

4 Schedule Change Details

Major Milestone Descriptions	Target Completion Dates (MM/YY)	
	Planned Date	**Revised Date**
Project Initiation – *Actual approval date*	12/22	
Scope approval w/VROMs (Go / No-go decision point) – *Actual approval date*		
ETER review and approval actual date – *Actual approval date*	01/23	
PMP / Approval to Execute – *Planned or Actual approval date*	01/23	
Transfer to Plant (TTP) / Go-Live – *Planned date*	03/23	06/23
Forecasted Close Date – *Planned date*	04/23	10/23

5 Compliance and Controls

Area	Required (Y/N)
Compliance Impact Assessment (contact: Jennifer Massey)	N
Business Continuity Plan/Business Impact Assessment (contact: Erin Swearingen) - *Always Required (excluding enhancement packages)*	Y
Reliability Compliance (NERC) (contact: Erin McClatchey)	N
SOX Business Controls Impact Assessment (contact: Krista Johnson)	Y
SOX Application Pre and Post Implementation Assessment (contact: Molly Favor)	Y
Security Impact Assessment (SIA) (contact: Shanna Pagniano) - *Always Required*	Y
TSA Directive Review (contact: Jennifer Truman)	N
PCI (Payment Card Industry) Compliance Assessment (contact: Shanna Pagniano)	Y
Network Impact Assessment (contact: Ignacio Chapa) - *Always Required*	Y

6 Funding Change Details

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Labor:	$126,398	$56,761	$183,159
Non-ET Labor:	$880	($80)	$800
Product:	$40,000	$0	$40,000
Professional Services:	$35,000	$18,464	$53,464
Other:	$2,500	$1,025	$3,525
AFUDC:	$3,125	$2,699	$5,824
Total:	**$207,903**	**$78,869**	**$286,772**

7 FERC Allocation of Project Costs

Accounting Asset Category	Installation *(107600)*	Removal *(108000)*	Total ($)

	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Hardware (FERC Account 391)	$0	$0	$0	**$0**
Communications Equipment (FERC Account 397)	$0	$0	$0	**$0**
Software (FERC Account 303)	$0	$285,772	$1,000	**$286,772**
Estimated Total Capital Cost:	**$0**	**$285,772**	**$1,000**	**$286,772**

Change Request Form

Project Name: Data and Analytic Platform (DAAP) Expansion 2023
Clarity Project ID: PR00016228
Acctg Project #: 009907185
Business Case Name: Enterprise Technology Modernization & Operational Efficiency
ER/BI: 5026-26W01
Risk or Issue ID: ISS00000974
Constraint(s): Funding
Submit Date: 11/8/2023

1 Key Roles & Project Information

Project Sponsor(s):	Hossein Nikdel	**Business Case Owner:**	Karen Schuh
Program Manager:	Elisabeth Sibulsky	**Project Coordinator:**	Jacob Weishaar
Domain Architect:	Jason Pegg	**Primary Product Owner:**	Jason Humbert
Steering Committee:	Michael Mudge, Hossein Nikdel	**Key Stakeholders:**	Elisabeth Sibulsky, Jason Pegg, Jason Humbert

2 Summary of Change(s)

Scope: No changes.

Schedule: No changes.

Funding: Additional funding is requested for the Data and Analytic Platform (DAAP) project to ensure the approved prioritized enhancements can resume and be completed by the end of this year. Cost forecast for Amazon Web Services (AWS) has increased due to increased usage of the DAAP. Resource availability to complete work on the project backlog has increased. Labor rates have also increased per resources moving from offshore to onshore. The additional funding will allow the development team to deliver the following improvements to the DAAP, such as:

- Compaction Framework – Improvements to the overall efficiency of how the datalake is constructed, which should result in faster availability of data, and less cost by using less space.
- Redshift Serverless – We currently utilize Amazon Redshift as a data warehouse that sits alongside our datalake (both part of the overall Logical Data Warehouse). Amazon has released a new licensing model that allows us to utilize Redshift without having to manage servers. This reduces costs and management effort and allows for easier performance scaling.
- Spark History Server – The Spark History Server is a User Interface that will monitor metrics and performance while processing data into the datalake. These historical metrics are helpful when improving the performance of the Datalake.
- Lake Formation – Amazon Web Services Lake Formation will decrease the amount of time it takes to expand Avista's datalake and will also provide easier management of data security in the datalake.

The primary development team's capability and capacity is currently aligned to deliver this work at this time to maximize resource utilization.

2.1 Business Impact

If this change request is not approved, Avista and Our Customers will not benefit from the efficiencies and performance improvements. The DAAP will not be able to use the latest technologies for better throughput, have more robust security, and achieve further cost reduction (for instance, reducing CPU cycles to save money in AWS). This would result in reduced performance and our ability to meet desired financial objectives. The technical capabilities that are necessary to support transformation and growth initiatives would be at risk.

3 Scope Change Details

Existing Deliverables	Changes to Deliverables
DAAP Enhancements as prioritized by stakeholders	No change
Functionality delivered through periodic releases will be covered under warranty for 30 days.	No change
A summarized list of deliverables released in each package will be provided to Project Accounting during the closing phase of each package.	No change
User Acceptance Testing (UAT)	No change
Security Impact Assessment (SIA)	No change
Network Impact Assessment (NIA)	No change

3.1 Where Will Technology Be Deployed

The Data and Analytic Platform is deployed in Amazon Web Services (AWS).

4 Schedule Change Details

Major Milestone Descriptions	Target Completion Dates (MM/YY)	
	Planned Date	Revised Date
Project Initiation – *Actual approval date*	12/2022	No change
Scope approval w/VROMs (Go / No-go decision point) – *Actual approval date*	N/A	No change
ETER review and approval actual date – *Actual approval date*	N/A	No change
PMP / Approval to Execute – *Planned or Actual approval date*	12/2022	No change
Transfer to Plant (TTP) / Go-Live – *Planned date*	12/2023	No change
Forecasted Close Date – *Planned date*	1/2024	No change

5 Compliance and Controls Requirements

Compliance Area	Required (Yes, No, *)
Compliance Impact Assessment	No
Business Continuity Plan/Business Impact Assessment	No
Reliability and Cyber Compliance (NERC)	No
SOX Business Controls Impact Assessment	No
SOX Application Pre and Post Implementation Assessment	No
Security Impact Assessment (SIA)	Yes
Payment Card Industry (PCI) Compliance Assessment	No
Network Impact Assessment (NIA)	Yes
FERC/Dam Safety and Cyber Security	No
Outage Coordination	No
Operational Licensing	No
Permits	No
Full Network Model Impact Assessment	No

5.1 Health, Safety, Security and Environmental (HSSE)

Health, Safety. Security, Environmental (HSSE) Area	Required (Yes, No, *)
Host Employer Safety Information Transfer (HESIT)	No

Environmental	No
Industrial Safety	No
Occupational Health	No
Permitting	No
Licensing	No
Security	No

6 Funding Change Details

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Labor:	$145,940	$175,998	$321,938
Non-ET Labor:	$0	$0	$0
Product:	$13,000	$0	$13,000
Professional Services:	$0	$38,821	$38,821
Other:	$766	($631)	$135
AFUDC:	$5,294	$6,556	$11,850
Total:	**$165,000**	**$220,744**	**$385,744**

7 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories**. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service, and removal and decommissioning of retired assets.

Accounting Asset Category	Installation *(107600)*		Removal *(108000)*	Total ($)
	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Hardware (FERC Account 391)	$0	$0	$0	**$0**
Communications Equipment (FERC Account 397)	$0	$0	$0	**$0**
Software (FERC Account 303)	$0	$385,744	$0	**$385,744**
Estimated Total Capital Cost:	**$0**	**$385,744**	**$0**	**$385,744**

Change Request Form

Project Name:	Cognos Upgrade 2022
Clarity Project ID:	PR00014251
Acctg Project #:	09907034
Business Case Name:	ET Modernization and Operational Efficiency
ER/BI:	5026 / 26W01
Risk or Issue ID:	ISS00000911; RSK0008559
Constraint(s):	Schedule, Funding
Submit Date:	05/19/2023

1 Key Roles & Project Information

Project Sponsor(s):	Hossein Nikdel	**Business Case Owner(s):**	Karen Schuh
Program Manager:	Leianne Raymond	**Project Manager:**	Cole Tanner
Steering Committee Members:	Nolan Steiner, Karen Schuh, Mike Mudge, Ian McLelland	**Primary Product Owner:**	Jason Humbert
		Other Stakeholders:	Jason Humbert, Leianne Raymond, Carol Markson, Jennifer McCauley

2 Summary of Change(s)

Resource constraints and competing priorities have delayed progress on the Cognos application upgrade, which has impacted the project schedule and budget. This upgrade has required efforts from multiple teams that have had fluctuating capacity due to additional project priorities, thus challenging the timeline. Additionally, there will be a staggered approach of user content to the update instance of Cognos, to allow each group an appropriate window for testing, which also extends the project timeline by one month. Additional funding is requested to accommodate for the additional labor hours and AFUDC associated to the necessary modification of the schedule.

2.1 Business Impact

If this change request is not approved, the application cannot be upgraded, resulting in an increased risk of security vulnerabilities, performance degradation, system reliability, and support. Moreover, Cognos users would fail to benefit from the updated version's latest features that are aimed to create business efficiencies.

2.2 Where Will Technology Be Deployed

Avista Data Center

3 Schedule Change Details

Major Milestone Descriptions	Target Completion Dates (MM/YY)	
	Planned Date	Revised Date
Project Initiation – *Actual approval date*	02/22	
ETER review and approval actual date – *Actual approval date*	07/22	
Transfer to Plant (TTP) / Go-Live – *Planned date*	04/23	05/23
Forecasted Close Date – *Planned date*	06/23	08/23

4 Compliance and Controls

Area	Required (Y/N)
Compliance Impact Assessment (contact: Jennifer Massey)	N
Business Continuity Plan/Business Impact Assessment (contact: Erin Swearingen) - *Always Required (excluding enhancement packages)*	Y
Reliability Compliance (NERC) (contact: Erin McClatchey)	N

SOX Business Controls Impact Assessment (contact: Krista Johnson)	N
SOX Application Pre and Post Implementation Assessment (contact: Molly Favor)	Y
Security Impact Assessment (SIA) (contact: Shanna Pagniano) - *Always Required*	Y
TSA Directive Review (contact: Jennifer Truman)	N
PCI (Payment Card Industry) Compliance Assessment (contact: Molly Favor)	N
Network Impact Assessment (contact: Ignacio Chapa) - *Always Required*	Y

5 Funding Change Details

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Labor:	$140,555	$31,765	$172,320
Non-ET Labor:	$1,541	$1,558	$3,099
Product:	$0	$0	$0
Professional Services:	$0	$0	$0
Other:	$4,709	($4,342)	$367
AFUDC:	$3,264	$1,769	$5,033
Total:	**$150,069**	**$30,750**	**$180,819**

6 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories**. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service, and removal and decommissioning of retired assets.

Accounting Asset Category	**Installation *(107600)***		**Removal *(108000)***	**Total ($)**
	Physical Product ($)	**Labor and Other ($)**	**Labor and Other ($)**	
Hardware (FERC Account 391)	$0	$0	$0	**$0**
Communications Equipment (FERC Account 397)	$0	$0	$0	**$0**
Software (FERC Account 303)	$0	$180,819	$0	**$180,819**
Estimated Total Capital Cost:	**$0**	**$180,819**	**$0**	**$180,819**

Change Request Form

Project Name: Cognos Upgrade 2023
Clarity Project ID: PR00014251
Acctg Project #: 09907034
Business Case Name: ET Modernization and Operational Efficiency
ER/BI: 5026 / 26W01
Risk or Issue ID: ISS00000911; RSK0008559; RSK00009018; RSK0009073; RSK00008068
Constraint(s): Scope, Schedule, Funding
Submit Date: 08/10/2023

1 Key Roles & Project Information

Project Sponsor(s):	Hossein Nikdel	**Business Case Owner(s):**	Karen Schuh
Program Manager:	Elisabeth Sibulsky	**Project Manager:**	Cole Tanner
Steering Committee Members:	Nolan Steiner, Karen Schuh, Mike Mudge, Ian McLelland	**Primary Product Owner:**	Jason Humbert
		Other Stakeholders:	Jason Humbert, Leianne Raymond, Carol Markson, Jennifer McCauley

2 Summary of Change(s)

Scope Request:
This is a request to add the following scope to the project:
- Integrate AppDynamics with Cognos Analytics to provide real-time visibility into application performance in order to help identify and address performance bottlenecks.

Schedule Request:
This is a request to extend the Forecasted Close Date from August 2023 to November 2023 (~90 days) to:
- Account for added time spent tracking and resolving issues during user testing.
- Integrate AppDynamics with Cognos Analytics in the upgraded instance of Cognos.
- Coordinate testing with different user groups.
- Account for delays due to the Inbound Voice Channel Refresh (IVR) project requiring the same resources.
- Identify a new resource to support the Cognos Report Writer role, which is critical for supporting user testing.
- Complete warranty support and operational handoff.
- Complete closing activities.

Funding Request:
This is a request to add $83,404 in funding to increase the budget from $180,818 to $264,222 to:
- Integrate AppDynamics with Cognos Analytics in the upgraded instance of Cognos.
- Continue user testing and coordination with various user groups.
- Track, research, and troubleshoot reported issues that emerge from user testing.
- Set up user Active Directory Groups with correct permissions.
- Increase project management labor due to schedule delays and to close out the project.
- Adjust the labor variances identified between Oracle and Clarity.

2.1 Business Impact

If this change request is not approved, half of Avista's Cognos users will still need to use the non-upgraded version of Cognos, resulting in an increased risk of security vulnerabilities, performance degradation, system reliability, and support. Moreover, these Cognos users wouldn't benefit from the updated version's latest features, such as the updated user interface, improved content navigation, faster dashboard performance, and built-in AI assistance.

3 Scope Change Details

Use Cases	Existing Deliverables	Changes to Deliverables
1-4	Application Upgrade to the most current version of Cognos	
1-4	Windows Server Upgrade (from 2012 to a newer OS)	
1-4	Upgrade Meta Manager to the most current version	
1-4	Application Testing in Model Office and/or Development	
1-4	Application Testing in Production	
1-4	User Acceptance Testing (UAT)	
3	Security Impact Assessment (SIA)	
4	Network Impact Assessment (NIA)	
1-4	30-day post implementation warranty	
1-4	Operational Handoff	
1-4		Integrate AppDynamics with Cognos Analytics

3.1 Where Will Technology Be Deployed

Avista Data Center

4 Schedule Change Details

Major Milestone Descriptions	Target Completion Dates (MM/YY)	
	Planned Date	Revised Date
Project Initiation – *Actual approval date*	02/22	
ETER review and approval actual date – *Actual approval date*	07/22	
Transfer to Plant (TTP) / Go-Live – *Planned date*	05/23	06/23
Forecasted Close Date – *Planned date*	08/23	11/23

5 Compliance and Controls Requirements

Compliance Area	Required (Yes, No, *)
Compliance Impact Assessment	No
Business Continuity Plan/Business Impact Assessment	Yes
Reliability and Cyber Compliance (NERC)	No
SOX Business Controls Impact Assessment	No
SOX Application Pre and Post Implementation Assessment	Yes
Security Impact Assessment (SIA)	Yes
Payment Card Industry (PCI) Compliance Assessment	No
Network Impact Assessment (NIA)	Yes
FERC/Dam Safety and Cyber Security	No
Outage Coordination	No
Operational Licensing	No
Permits	No
Full Network Model Impact Assessment	No

**Will be assessed during the Planning Phase*

Change Request Form

5.1 Health, Safety, Security and Environmental (HSSE)

Health, Safety. Security, Environmental (HSSE) Area	Required (Yes, No, *)
Host Employer Safety Information Transfer (HESIT)	No
Environmental	No
Industrial Safety	No
Occupational Health	No
Permitting	No
Licensing	No
Security	No

**Will be assessed during the Planning Phase*

6 Funding Change Details

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Labor:	$172,318	$84,409	$256,727
Non-ET Labor:	$3,099	($1,205)	$1,894
Product:	$0	$0	$0
Professional Services:	$0	$0	$0
Other:	$367	($296)	$71
AFUDC:	$5,034	$496	$5,530
Total:	**$180,818**	**$83,404**	**$264,222**

7 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories**. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service, and removal and decommissioning of retired assets. "Removal" is labor, professional service and other misc. costs that are associated with the removal of equipment that is retired.

Accounting Asset Category	Installation *(107600)*		Removal *(108000)*	Total ($)
	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Hardware (FERC Account 391)	$0	$0	$0	**$0**
Communications Equipment (FERC Account 397)	$0	$0	$0	**$0**
Software (FERC Account 303)	$0	$264,223	$0	**$264,223**
Estimated Total Capital Cost:	**$0**	**$264,223**	**$0**	**$264,223**

Change Request Form

Project Name: Cognos Upgrade 2023
Clarity Project ID: PR00014251
Acctg Project #: 09907034
Business Case Name: ET Modernization and Operational Efficiency
ER/BI: 5026 / 26W01
Risk or Issue ID: ISS00000984; ISS00000985; RSK00009082; RSK00008559; RSK00009264
Constraint(s): Scope, Schedule, Funding
Submit Date: 12/20/2023

1 Key Roles & Project Information

Project Sponsor(s):	Hossein Nikdel	**Business Case Owner(s):**	Karen Schuh
Program Manager:	Elisabeth Sibulsky	**Project Manager:**	Cole Tanner
Steering Committee Members:	Nolan Steiner, Karen Schuh, Mike Mudge, Ian McLelland	**Primary Product Owner:**	Stacey Martin
		Other Stakeholders:	Stacey Martin, Elisabeth Sibulsky, Carol Markson, Jennifer McCauley

2 Summary of Change(s)

Scope Request:
This is a request to add the following scope to the project:

- Perform an additional Cognos Version Upgrade from 11.2.3 to 11.2.4 to resolve identified security vulnerabilities.

Schedule Request:
This is a request to extend the Forecasted Close Date from November 2023 to April 2024 (~120 days) due to:

- Provide end users' additional time to test content in new upgraded environment prior to transitioning their content to the new active upgraded environment.
- Resolve unforeseen bugs that come up during testing that require effort to research and troubleshoot
- Account for higher priority projects requiring the same resources.
- Change in internal resources performing the upgrade.
- Completion of warranty support and operational handoff.
- Completion of closing activities.

Funding Request:
This is a request to add $56,322 in funding, increasing the budget from $264,222 to $320,544 to cover:

- Additional time from technical resources to support ongoing user testing and issue resolution.
- Increased funding to perform an additional version upgrade from 11.2.3 to 11.2.4.
- Additional funding needed to onboard a new technical team taking over the project.
- Overall schedule delays contributing to increased project spend.
- Increased project management labor due to schedule delays and to close out the project.
- Adjustment of labor variances identified between Oracle and Clarity.

2.1 Business Impact

If this change request is not approved, half of Avista's Cognos users will still need to use the non-upgraded version of Cognos, resulting in an increased risk of security vulnerabilities, performance degradation, system reliability, and support. Moreover, these Cognos users wouldn't benefit from the updated version's latest features, such as the updated user interface, improved content navigation, faster dashboard performance, and built-in AI assistance.

Change Request Form

3 Scope Change Details

Use Cases	Existing Deliverables	Changes to Deliverables
1-4	Upgrade Cognos Application to Version 11.2.3	Upgrade Cognos Application to Version 11.2.4
1-4	Windows Server Upgrade (from 2012 to a newer OS)	
1-4	Upgrade Meta Manager to the most current version	
1-4	Application Testing in Model Office and/or Development	
1-4	Application Testing in Production	
1-4	User Acceptance Testing (UAT)	
3	Security Impact Assessment (SIA)	
4	Network Impact Assessment (NIA)	
1-4	30-day post implementation warranty	
1-4	Operational Handoff	
1-4	Integrate AppDynamics with Cognos Analytics	

3.1 Where Will Technology Be Deployed

Upgraded instance of Cognos was deployed on 5 servers in Avista's Data Center. The existing servers running Cognos Version 11.1.5 will be decommissioned at the end of the project.

4 Schedule Change Details

Major Milestone Descriptions	Target Completion Dates (MM/YY)	
	Planned Date	Revised Date
Project Initiation – *Actual approval date*	02/22	
ETER review and approval actual date – *Actual approval date*	07/22	
Transfer to Plant (TTP) / Go-Live – *Planned date*	06/23	
Forecasted Close Date – *Planned date*	11/23	04/24

5 Compliance and Controls Requirements

Compliance Area	Required (Yes, No, *)
Compliance Impact Assessment	No
Business Continuity Plan/Business Impact Assessment	Yes
Reliability and Cyber Compliance (NERC)	No
SOX Business Controls Impact Assessment	No
SOX Application Pre and Post Implementation Assessment	Yes
Security Impact Assessment (SIA)	Yes
Payment Card Industry (PCI) Compliance Assessment	No
Network Impact Assessment (NIA)	Yes
FERC/Dam Safety and Cyber Security	No
Outage Coordination	No
Operational Licensing	No
Permits	No
Full Network Model Impact Assessment	No

**Will be assessed during the Planning Phase*

5.1 Health, Safety, Security and Environmental (HSSE)

Health, Safety. Security, Environmental (HSSE) Area	Required (Yes, No, *)
Host Employer Safety Information Transfer (HESIT)	No
Environmental	No
Industrial Safety	No
Occupational Health	No
Permitting	No
Licensing	No
Security	No

**Will be assessed during the Planning Phase*

6 Funding Change Details

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Labor:	$256,728	$55,702	$312,430
Non-ET Labor:	$1,894	$412	$2,306
Product:	$0	$0	$0
Professional Services:	$0	$0	$0
Other:	$70	$208	$278
AFUDC:	$5,530	$0	$5,530
Total:	**$264,222**	**$56,322**	**$320,544**

7 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories**. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service, and removal and decommissioning of retired assets.

Accounting Asset Category	Installation *(107600)*		Removal *(108000)*	Total ($)
	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Hardware (FERC Account 391)	$0	$0	$0	**$0**
Communications Equipment (FERC Account 397)	$0	$0	$0	**$0**
Software (FERC Account 303)	$0	$320,544	$0	**$320,544**
Estimated Total Capital Cost:	**$0**	**$320,544**	**$0**	**$320,544**

ET Modernization & Operational Efficiency (ETMOE) Governance Meeting

January 2023

Karen Schuh – Business Case Owner
Leianne Raymond – Program Manager

Agenda

- 2022 Financials
- 2022 Variance
- ETMOE Project Status / Headlines
- 2022 TTP
- 2023 Overview / TTP
- Five Year Plan
- Decisions / Decision Ledger
    - 2023 Governance

Business Case Financial Summary

Actuals through: 12/31/22

Current Month

Current or Previous Year? Previous

2022 Business Case Financials

Business Case	CPG Approved Spend	YTD Actual Spend	Forecast Spend	Exp. Annual Spend	Variance	% CPG Apprv. Spent
ET Modernization & Operational Efficiency -	$1,803,792	$2,241,255	$0	$2,241,255	($437,463)	124.25%
Grand Total	**$1,803,792**	**$2,241,255**	**$0**	**$2,241,255**	**($437,463)**	**124.25%**

Cognos Licensing opportunity (details in slide 6)

- Without Cognos Licensing

Current or Previous Year? Previous

2022 Business Case Financials

Business Case	CPG Approved Spend	YTD Actual Spend	Forecast Spend	Exp. Annual Spend	Variance	% CPG Apprv. Spent
ET Modernization & Operational Efficiency - Techn	$1,803,792	$1,777,286	$0	$1,777,286	$26,506	98.53%
Grand Total	**$1,803,792**	**$1,777,286**	**$0**	**$1,777,286**	**$26,506**	**98.53%**

Financials by Quarter

Attachment C

Business Case	Project	Phase	Actual 2022 Q1	Q2	Q3	Q4	Grand Total
ET Modernization & Operation..	Adobe Creative Cloud Packaging - 09906858	Complete	$946				$946
	Alation Licenses 2022 (2 Year agreement) - 09907107	Complete			$67,003		$67,003
	App Dynamics Expansion 2021 - 09906784	Complete	$1,181	$94			$1,274
	Application Programming Interface (API)	Complete		$166			$166
	Azure DevOps Features Expansion 2021 - 09906797	Complete	$1,471				$1,471
	BizTalk Upgrade 2021 - 09906774	Complete	$60,382	$897			$61,279
	Cognos/BI Expansion 2021 - 09906806	Complete	$560	$521			$1,081
	Data Analytic Platform Expansion 2021 - 09906805	Complete	$1,358				$1,358
	Globalscape Upgrade 2020 - 09906730	Complete	($2,906)				($2,906)
	Intranet Expansion 2021 - 09906783	Complete	$904				$904
	Smarsh Vantage Licenses 2021 - 09906945	Complete	$269				$269
	VibroZoom Licensing - 09806207	Complete	$7,721				$7,721
	Azure DevOps Features/Expansion 2022 - 09906997	Closing	$13,822	$11,587	$28,251	($3,961)	$49,698
	Clarity Application Upgrade 2022 - 09907040	Complete	$2,649	$70,977	$50,484	($8)	$124,101
	BI / ETL Expansion 2022 Pkg. #1 - 09906990	Closing	$17,975	$47,660	$2,612	$22	$68,269
	Alation Upgrade 2022 - 09907015	Complete	$4,204	$11,511	$5,681	$242	$21,637
	Devolutions: Remote Desktop Manager Enterprise (3 y..	Complete			$14,414	$517	$14,931
	Globalscape Upgrade 2022 - 09907006	Complete	$47,292	$48,586	$14,119	$2,463	$112,460
	App Dynamics Expansion 2022 - 09906992	Closing	$11,053	$12,086	$9,419	$8,799	$41,357
	Intranet Features/Expansion 2022 - 09906995	Closing	$23,308	$15,679	$8,942	$10,877	$58,806
	Enterprise Content Management (ECM)	Closing	$222	$21,238	$19,388	$23,993	$64,841
	BI / ETL Expansion 2022 Pkg. #2 - 09906991	Closing			$51,407	$24,060	$75,467
	API Management Expansion 2022 - 09907068	Execution		$798	$6,572	$26,358	$33,728
	ITSM Implementation Phase 1: IT Asset Management (..	Planning				$32,624	$32,624
	Cognos Upgrade 2022 - 09907034	Execution	$2,655	$7,659	$34,780	$37,294	$82,389
	Azure DevOps Upgrade - 09907165	Execution				$54,873	$54,873
	Data Analytic Platform (DAAP) Expansion 2022 - 0990..	Closing	$56,290	$55,137	$92,623	$93,337	$297,387
	Tableau License Renewal 2022 - 09907125	Complete				$122,726	$122,726
	Acrobat Licenses -2022 (3 year term) - 09907170	Closing				$162,714	$162,714
	Visual Studio License Renewal - 09907126	Complete				$218,710	$218,710
	Cognos Licensing (5 Year term) - 09907169	Complete				$463,969	$463,969
	Total		$251,356	$304,594	$405,696	$1,279,609	$2,241,255

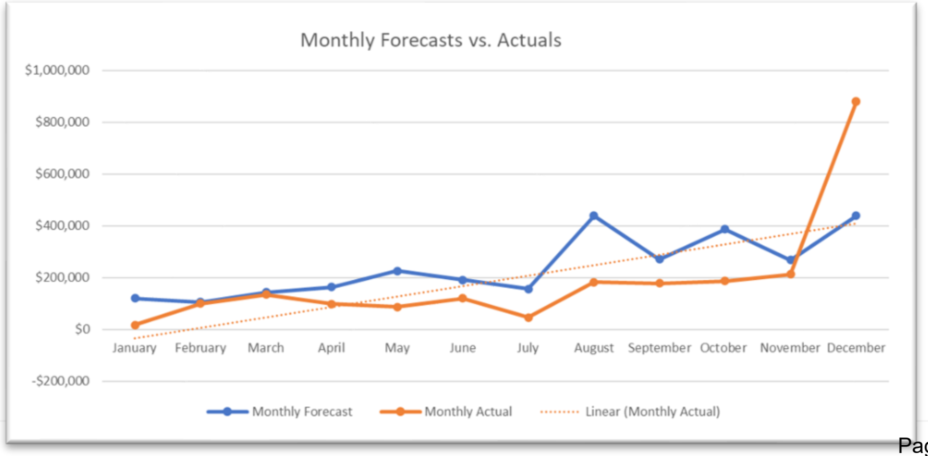
Monthly Forecast Variance

Total Forecast variance by month

Project	Forecast December	Actuals	Dec. vs Actual Variance
API Management Expansion 2022	$44,797	$33,894	-$10,903
Acrobat Licenses	$164,536	$162,714	-$1,822
Adobe Creative Cloud Packaging - 09906858	$946	$946	$0
Alation Licenses 2022 - 3 Year agreement	$67,003	$67,003	$0
Alation Upgrade 2022 - 09907015	$22,754	$21,637	-$1,117
App Dynamics Expansion 2021 - 09906784	$1,274	$1,274	$0
App Dynamics Expansion 2022 - 09906992	$49,021	$41,357	-$7,664
Azure DevOps Features Expansion 2021 - 09906797	$1,471	$1,471	$0
Azure DevOps Expansion 2022 - 09906997	$100,467	$49,698	-$50,769
Azure DevOps Upgrade	$52,000	$54,873	$2,873
BI / ETL Expansion 2022 Pkg. #1 - 09906990	$69,647	$68,269	-$1,378
BI / ETL Expansion 2022 Pkg. #2 - 09906991	$76,648	$75,467	-$1,181
BizTalk Upgrade 2021 - 09906774	$61,279	$61,279	$0
Clarity Application Upgrade 2022	$124,101	$124,101	$0
Cognos Upgrade 2022 - 09907034	$81,362	$82,389	$1,027
Cognos/BI Expansion 2021 - 09906806	$1,081	$1,081	$0
Data Analytic Platform (DAAP) Expansion 2022 - 09906994	$289,380	$297,387	$8,007
Data Analytic Platform Expansion 2021 - 09906805	$1,358	$1,358	$0
Devolutions Remote Desktop	$15,132	$14,931	-$201
Enterprise Content Management (ECM) Features/Expansion 2022	$68,155	$64,841	-$3,314
Globalscape Upgrade 2020 - 09906730	-$2,906	-$2,906	$0
Globalscape Upgrade 2022 - 09907006	$111,741	$112,460	$719
Intranet Expansion 2021 - 09906783	$904	$904	$0
Intranet Features/Expansion 2022 - 09906995	$62,012	$58,806	-$3,206
ITSM Phase 1 - ITAM	$67,017	$32,624	-$34,393
Minor Application Purchases and Licenses -2022	$0	$0	$0
Smarsh Vantage Licenses 2021 - 09906945	$269	$269	$0
Tableau License Renewal 2022	$122,726	$122,726	$0
Tableau Upgrade 2022 - 09907016	$0	$0	$0
VibroZoom Licensing - 09806207	$7,721	$7,721	$0
Visual Studio Licensing	$138,516	$218,710	$80,194
Cognos License Renewal	$0	$463,969	$463,969
Total	$1,800,415	$2,241,255	$440,840

Monthly planned forecast to actuals

Month	Monthly Forecast	Monthly Actual	Variance
January	$120,338	$17,184	-$103,154
February	$104,970	$100,151	-$4,819
March	$143,255	$134,022	-$9,233
April	$162,790	$98,620	-$64,170
May	$225,881	$85,990	-$139,891
June	$190,329	$119,984	-$70,345
July	$155,461	$45,785	-$109,676
August	$438,315	$182,640	-$255,675
September	$271,037	$177,271	-$93,766
October	$387,023	$186,858	-$200,165
November	$267,634	$213,072	-$54,562
December	$439,080	$879,753	$440,673
Average	*$242,176*	*$186,778*	*-$55,399*



ETMOE Project Status

Attachment C

Updates, Risks, Milestones, Questions, Decisions, etc.

HEADLINES TODAY

❑ Visual Studio Licensing variance

Why? (From Tiffany Adams):

- The capital charges for Visual Studio had changed from 38%/62% capital/O&M split to 80/20 split
- *(The 38%/62% split was from years ago and we did not feel comfortable using that split when our policy is to use 80/20 for software contracts that have the license, O&M lumped together.)*

❑ Cognos Licensing variance

Why?

- Reduction opportunity identified by IT Finance
- Needed to be executed by 12/21/22
- Move from perpetual to term licensing through new vendor (DXC)
- Created 30% overall cost reduction over next 5 years
- 40k overall expense reduction in 2023

How?

- Review of the 2022 ET capital Business Cases total expected spend was estimated favorable and could be utilized to fund opportunity.
- The direction and approval from IT Finance in conjunction with CPG Leadership was to move forward with the purchase of the licenses under ETMOE
- Document the decision and impact for accounting and transparency purposes (CPG CR signed and sent to CPG).

AVISTA

Transfer to Plant (TTP) 2022

Cognos Upgrade – 100k
Azure DO Upgrade – 200k

Transfer to Plant (TTP) by Project

Project: (All) ▾

Use the project filter to exclude projects from both the table below and the bar chart above.
Hover over the 'Business Function' header and click the '-' to roll-up and the '+' to drill-down

Year: 2022 ▾

How to download this data

Business Fu..	ER + Desc	BI + Desc	Project	Jan	Feb	Mar	Apr	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ET Subfunction	5026 - ET Modernization & Op Efficiency - Technology	26W01 - ET Modernization & Op Efficiency - Technology	Data Analytic Platform (DAAP) Expa..											$297,387	$297,387
			Visual Studio License Renewal - 099..										$138,516	$80,194	$218,710
			BI / ETL Expansion 2022 Pkg. #2 - 09..											$75,467	$75,467
			Enterprise Content Management (EC..											$64,841	$64,841
			Intranet Features/Expansion 2022 - ..											$58,806	$58,806
			Azure DevOps Features/Expansion 2..											$49,698	$49,698
			App Dynamics Expansion 2022 - 099..											$41,357	$41,357
			API Management Expansion 2022 - 0..											$33,728	$33,728
			Globalscape Upgrade 2022 - 099070..						$98,800	$10,089	$1,108	$343	$796	$1,324	$112,460
			Devolutions: Remote Desktop Mana..									$14,414		$517	$14,931
			Alation Upgrade 2022 - 09907015					$15,714	$1,104	$2,169	$2,408	($65)		$307	$21,637
			BI / ETL Expansion 2022 Pkg. #1 - 09..					$65,635	$1,763	$607	$241			$22	$68,269
			VibroZoom Licensing - 09806207		$7,721										$7,721
			Smarsh Vantage Licenses 2021 - 099..	($52)	$320										$269
			Intranet Expansion 2021 - 09906783	$541	$363										$904
			Globalscape Upgrade 2020 - 099067..	($2,906)											($2,906)
			Data Analytic Platform Expansion	($392)	$1,751										$1,358
			Cognos/BI Expansion 2021 - 099068..	$86	$311	$164	$521								$1,081
			Clarity Application Upgrade 2022 - 0..					$73,625	$21,810	$10,049	$18,625	($8)			$124,101
			BizTalk Upgrade 2021 - 09906774	$7,109	$43,091	$10,183	$897								$61,279
			Azure DevOps Features Expansion 2..	$885	$586										$1,471
			Application Programming Interface (..					$166							$166
			App Dynamics Expansion 2021 - 099..	$471	$545	$164	$94								$1,274
			Alation Licenses 2022 (2 Year agree..								$67,003				$67,003
			Adobe Creative Cloud Packaging - 09..	$269	$485	$192									$946
Grand Total				$6,011	$55,173	$10,703	$1,512	$155,141	$123,476	$22,915	$89,386	$14,683	$139,312	$703,649	$1,321,961

Project Status Overview

Attachment C

Project	Phase	Year of La..	Status Report Update	Key Accomplishments	Upcoming Activities	Budget Status	Schedule Status	Scope Status
API Management Expansion 2022 - 09907068	Execution	2022	All work in 2022 has wrapped up.	All work in 2022 has wrapped up.	Lessons learned. GOS/PPR			
App Dynamics Expansion 2022 - 09906992	Closing	2022	Ops team is working on updating the diagram before SIA can be completed.	Approval to close	Security to review and process SIA for final approval.			
Azure DevOps Features/Expansion 2022 - 09906997	Closing	2022	TTP complete. ATC submitted for approval.	TTP complete. ATC submitted for approval.	Hold lessons learned meeting in January 2023. GOS/PPR			
BI / ETL Expansion 2022 Pkg. #1 - 09906990	Closing	2022	NIA has been submitted. Waiting for network to process.	No Change	Will need to reach out to project accounting to let them know not to hard close the project yet.			
BI / ETL Expansion 2022 Pkg. #2 - 09906991	Closing	2022	Project has been Transfer to Plant and approval to close submitted and processed.	TTP is completed Approval to close	Submit SIA Network to process NIA			
Data Analytic Platform (DAAP) Expansion 2022 - 09906994	Closing	2022	This project has been transferred to plant. Approval to Close has been submitted.	Second change request has been approved.	Network to process NIA.			
Enterprise Content Management (ECM) Features/Expansion 2022 - 09907043	Closing	2022	Project has been transferred to plant. NIA has been submitted. Approval to Close has been processed.	Project has been transferred to plant.	Network to process NIA.			
Intranet Features/Expansion 2022 - 09906995	Closing	2022	Project has been transferred to plant. SIA has been completed. Approval to Close has been submitted.	Project has been transferred to plant. SIA has been completed. Approval to Close has been submitted.	Network to process NIA.			
Acrobat Licenses -2022 (3 year term) - 09907170	Closing	2023						
Azure DevOps Upgrade - 09907165	Execution	2023	Team will be reviewing the upgrade plan for v2022 and advising on the best path forward from the DB perspective, considering the other applications with the DB pool and version jump from 2012 to 2019.	None.	Collaborate with intellitect for the contract change order. Meet with Phil and team to discuss next steps in detail to upgrade to 2022.			
Cognos Upgrade 2022 - 09907034	Execution	2023	Preparing lower environment for testing. Gathering information from various user groups before migrating reports.	Change request has been approved	Finance group to begin testing in Lower Environment once AD group is setup.			
ITSM Implementation Phase 1: IT Asset Management (ITAM) - 09907141	Planning	2023	Received ROMs from all 4 ServiceNow Implementors. Will begin formal RFP process early next week.	Charter is approved in Clarity	Upcoming steerco to solicit decision regarding ServiceNow Licensing.			

2023 Financial Summary

Current or Previous Year? Current

2023 Business Case Financials

Business Case	CPG Approved Spend	YTD Actual Spend	Forecast Spend	Exp. Annual Spend	Variance	% CPG Apprv. Spent
ET Modernization & Operational Efficiency -	$3,800,000	$0	$4,148,429	$4,148,429	$348,429	0%
Grand Total	$3,800,000	**$0**	**$4,148,429**	**$4,148,429**	$348,429	0%

2023 Project Forecast

Attachment C

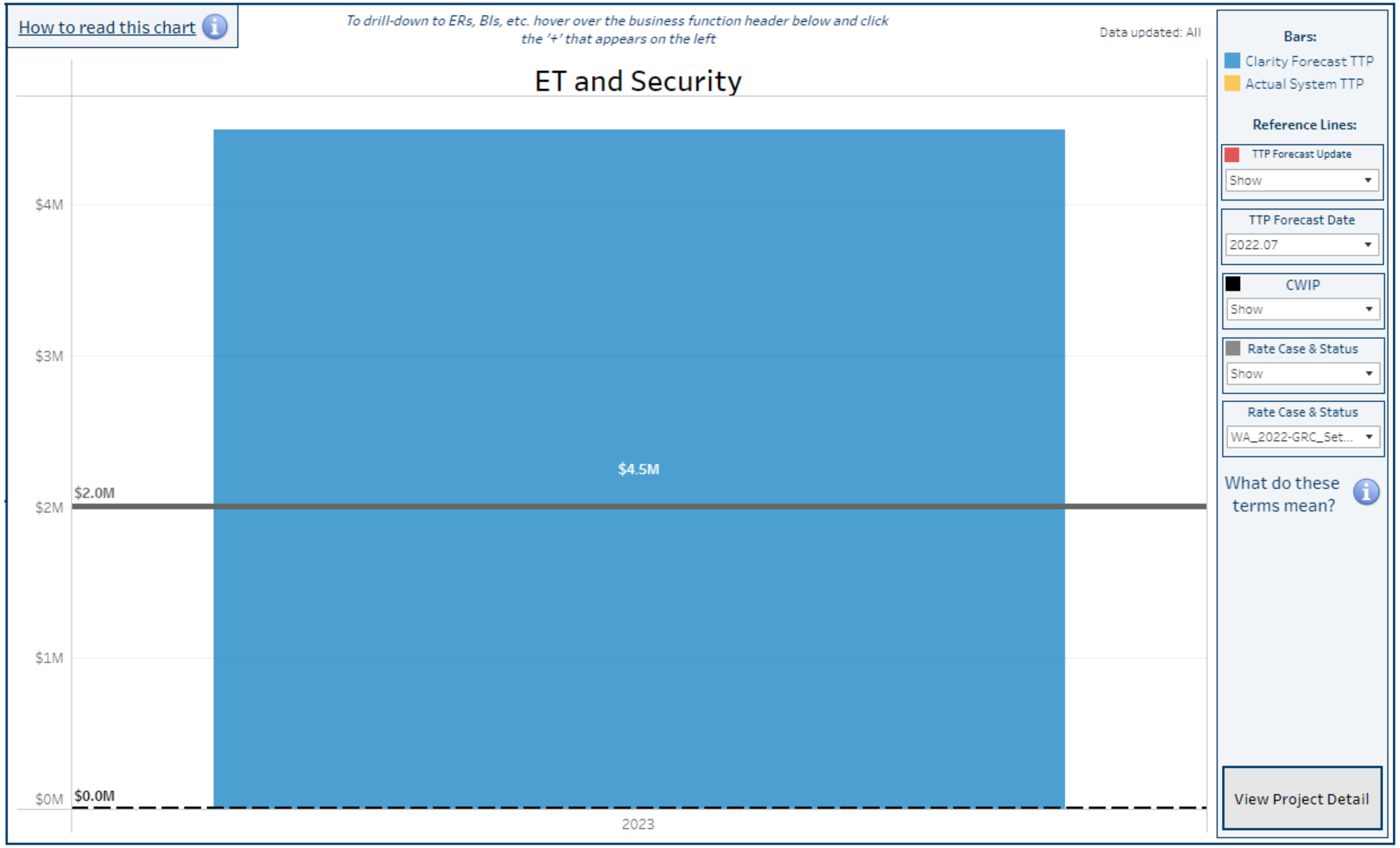
Project	Phase	Forecast 2023 Q1	Q2	Q3	Q4	Grand Total
ITSM Implementation Phase 1: IT Asset Management (..	Planning	$425,430	$409,747	$140,682	$21,518	$997,376
App Dynamics Licensing 2023	Queued	$645,000				$645,000
Mulesoft/API License Renewal 2023	Queued		$560,000			$560,000
IT Service Management (ITSM) Implementation - Phas..	Queued			$189,064	$355,937	$545,000
Software Composition Analysis (SCA)	Queued	$36,966	$102,127	$57,248	$78,659	$275,000
Azure DevOps Upgrade - 09907165	Execution	$123,405	$74,611	$1,903		$199,920
DAAP Expansion 2023 - 09907185	Execution	$44,276	$45,495	$44,409	$30,821	$165,000
BI / ETL Expansion 2023 Pkg. #1 - 09907188	Execution	$37,422	$37,578			$75,000
BI / ETL Expansion 2023 Pkg. #2 - 09907189	Queued			$33,764	$41,236	$75,000
Cognos Upgrade 2023	Queued			$40,006	$29,994	$70,000
FME Application/Server Upgrade 2023	Queued	$21,985	$34,760	$3,255		$60,000
API Management Tool Expansion 2023 - 09907179	Execution	$11,093	$12,719	$15,899	$10,289	$50,000
Azure DevOps Expansion 2023 - 09907192	Queued	$6,062	$11,816	$20,695	$11,427	$50,000
Vuetify Upgrade 2023	Queued	$11,737	$14,026	$12,506	$11,732	$50,000
Intranet Expansion 2023 - 09907187	Execution	$12,254	$12,651	$12,672	$12,423	$50,000
ECM Expansion 2023 - 09907184	Execution	$12,718	$12,737	$12,785	$11,760	$50,000
Globalscape Upgrade 2023	Queued		$4,703	$13,440	$31,857	$50,000
App Dynamics Expansion 2023 - 09907186	Execution	$10,805	$12,278	$12,287	$14,629	$50,000
Java AMC Upgrade 2023	Queued		$6,940	$14,859	$18,201	$40,000
Cognos Upgrade 2022 - 09907034	Execution	$26,142	$7,012			$33,154
Enterprise Content Management (ECM) Application U..	Queued				$25,709	$25,709
Tableau Creator Upgrade 2023	Queued	$1,813	$8,187			$10,000
Alation Upgrade 2023	Queued	$1,605	$8,395			$10,000
BI / ETL Expansion 2022 Pkg. #2 - 09906991	Closing	$2,189				$2,189
API Management Expansion 2022 - 09907068	Execution	$2,134				$2,134
Intranet Features/Expansion 2022 - 09906995	Closing	$1,644				$1,644
App Dynamics Expansion 2022 - 09906992	Closing	$1,605				$1,605
BI / ETL Expansion 2022 Pkg. #1 - 09906990	Closing	$1,377				$1,377
Data Analytic Platform (DAAP) Expansion 2022 - 0990..	Closing	$1,184				$1,184
Enterprise Content Management (ECM)	Closing	$937				$937
Azure DevOps Features/Expansion 2022 - 09906997	Closing	$878				$878
Acrobat Licenses -2022 (3 year term) - 09907170	Closing	$320				$320
Total		$1,440,983	$1,375,782	$625,472	$706,192	$4,148,429

Keep
Java AMC Upgrade
Vuetify Upgrade

Removed
BizTalk Upgrade

Validate:
Cognos Upgrade
Mulesoft API License renewal

2023 TTP



Projects to TTP (Click link for list):

[Business Case Transfer-to-Plant (TTP) Comparison: ET Project Detail - Blow-Up - Tableau Server (corp.com)]

Five Year Plan

Year	Requested Amount	CPG Approved Amount	*Variance (Requested vs. Approved)*	% of allocation received	Current Forecast (Expected Spend)	Variance (CPG Approved vs. Expected Spend)	
2023	$3,900,000	**$3,800,000**	*($100,000)*	97%	**$4,148,429**	($348,429)	ITAM, Azure DevOps Upgrade and Cognos Upgrade push into 2023 / SCA / Mulesoft and App D Licensing
2024	$2,950,000	**$2,350,000**	*($600,000)*	80%	**$3,195,676**	($845,676)	Tableau License Renewal (changed agreement). Clarity, BizTalk and ECM Upgrade
2025	$1,960,000	**$1,460,000**	*($500,000)*	74%	**$1,716,146**	($256,146)	
2026	$3,475,000	**$2,975,000**	*($500,000)*	86%	**$3,490,216**	($515,216)	
2027	$2,380,000	**$1,880,000**	*($500,000)*	79%	**$2,659,704**	($779,704)	Non-Production Dev. Env?
Total	$14,665,000	**$12,465,000**	*($2,200,000)*	85%	**$15,121,376**	**($2,656,376)**	

2024 Projects

Projects 2023+

Business Case	Project	Goal	2024 Q1	2024 Q2	2024 Q3	2024 Q4	Grand Total
ET Modernization & Operational Efficiency - Techn	Alation Licenses 2024 - 2 Year agreement	Run the Business				$88,000	$88,000
	Alation Upgrade - 2024	Run the Business	$1,374	$8,626			$10,000
	API Management Expansion 2024	Run the Business	$6,677	$18,258	$24,242	$5,822	$55,000
	App Dynamics Expansion 2024	Run the Business	$16,642	$18,272	$17,639	$19,447	$72,000
	Azure DevOps Features/Expansion 2024	Run the Business	$6,675	$10,613	$10,771	$6,940	$35,000
	Azure DevOps Upgrade 2024	Run the Business		$16,851	$24,511	$8,638	$50,000
	BI / ETL Expansion 2024	Run the Business	$32,637	$42,898	$34,096	$25,369	$135,000
	BizTalk Upgrade 2023 / 2024	Run the Business	$414,617	$61,767			$476,384
	Clarity Application Upgrade 2024	Run the Business		$70,625	$72,624	$56,751	$200,000
	Cognos Upgrade 2024	Run the Business			$28,056	$41,944	$70,000
	Enterprise Content Management (ECM) Application Upgrade	Run the Business	$83,663	$90,628			$174,291
	Enterprise Content Management (ECM) Features/Expansion	Run the Business	$15,588	$14,739	$13,740	$15,934	$60,000
	Globalscape Upgrade 2024	Run the Business	$15,985	$27,172	$27,172	$4,670	$75,000
	Intranet Features/Expansion 2024	Run the Business	$13,000	$13,201	$13,403	$10,396	$50,000
	IT Service Management (ITSM) Implementation - Phase 2	Grow the Business	$420,193	$249,807			$670,000
	Minor Application Purchases and Licenses -2024	Run the Business	$11,500	$17,059	$16,817	$14,624	$60,000
	Tableau Creator Upgrade 2024	Run the Business	$919	$5,347	$3,734		$10,000
	Tableau License Renewal 2024 (with SalesForce renewal)	Run the Business		$250,000			$250,000
	Vuetify Upgrades 2024	Run the Business	$10,756	$13,972	$14,187	$11,086	$50,000
	Total		$1,050,225	$929,837	$300,992	$309,622	$2,590,676

2025 Projects

Projects 2023+

Business Case	Project	Goal	2025 Q1	2025 Q2	2025 Q3	2025 Q4	Grand Total
ET Modernization & Operational Efficiency - Techn	Alation Upgrade - 2025	Run the Business	$205	$9,419	$1,377		$11,000
	API Management Expansion 2025	Run the Business	$7,923	$12,367	$16,560	$18,150	$55,000
	App Dynamics Expansion 2025	Run the Business	$15,499	$20,258	$20,858	$18,385	$75,000
	Azure DevOps Features/Expansion 2025	Run the Business	$8,939	$10,200	$10,528	$10,333	$40,000
	BI / ETL Expansion 2025	Run the Business	$38,059	$47,606	$35,945	$28,390	$150,000
	BizTalk Upgrade 2025 / 2026	Run the Business			$98,924	$113,313	$212,237
	Cognos Upgrade 2025	Run the Business			$29,206	$20,794	$50,000
	Data Analytic Platform (DAAP) Expansion 2025	Run the Business	$25,043	$35,361	$38,113	$51,483	$150,000
	Devolutions: Remote Desktop Manager Enterprise (3 year	Run the Business			$20,000		$20,000
	Enterprise Content Management (ECM) Application Upgrade	Run the Business				$64,192	$64,192
	Enterprise Content Management (ECM) Features/Expansion	Run the Business	$11,528	$12,137	$12,264	$9,072	$45,000
	FME Application Upgrade 2025	Run the Business		$6,673	$20,716	$2,610	$30,000
	Globalscape Upgrade 2025	Run the Business	$8,555	$32,273	$38,873	$20,299	$100,000
	Intranet Features/Expansion 2025	Run the Business	$12,789	$13,194	$13,395	$10,622	$50,000
	IT Service Management (ITSM) Expansion 2025	Grow the Business	$98,454	$134,574	$134,574	$132,397	$500,000
	Java AMC Upgrade 2025	Run the Business		$3,145	$18,298	$19,557	$41,000
	Minor Application Purchases and Licenses -2025	Run the Business	$9,839	$12,995	$16,920	$19,962	$59,716
	Tableau Creator Upgrade 2025	Run the Business	$5,097	$7,903			$13,000
	Visual Studio License Renewal 2025	Run the Business				$114,000	$114,000
	Vuetify Upgrades 2025	Run the Business	$11,962	$13,692	$13,903	$10,443	$50,000
	Total		$253,892	$371,798	$540,454	$664,002	$1,830,146

2026/2027 Projects

Projects 2023+

Business Case	Project	Goal	2026	2027	Grand Total
ET Modernization & Operational Efficiency - Techn	Alation Licenses 2026 -2 Year agreement	Run the Business	$90,000		$90,000
	Alation Upgrade - 2026	Run the Business	$12,000		$12,000
	Alation Upgrade - 2027	Run the Business		$18,000	$18,000
	API Management Expansion 2026	Run the Business	$50,000		$50,000
	API Management Expansion 2027	Run the Business		$62,500	$62,500
	App Dynamics Expansion 2026	Run the Business	$75,000		$75,000
	App Dynamics Expansion 2027	Run the Business		$77,500	$77,500
	App Dynamics Licensing 2026	Run the Business	$650,000		$650,000
	Azure DevOps Features/Expansion 2026	Run the Business	$40,000		$40,000
	Azure DevOps Features/Expansion 2027	Run the Business	$980	$39,020	$40,000
	Azure DevOps Upgrade 2026	Run the Business	$50,000		$50,000
	BI / ETL Expansion 2026	Run the Business	$125,000		$125,000
	BI / ETL Expansion 2027	Run the Business		$150,000	$150,000
	BizTalk Upgrade 2025 / 2026	Run the Business	$387,763		$387,763
	BizTalk Upgrade 2027 / 2028	Run the Business		$376,458	$376,458
	Clarity Application Upgrade 2026	Run the Business	$200,000		$200,000
	Cognos Upgrade 2026	Run the Business	$50,000		$50,000
	Cognos Upgrade 2027	Run the Business		$75,000	$75,000
	Data Analytic Platform (DAAP) Expansion 2026	Run the Business	$150,000		$150,000
	Data Analytic Platform (DAAP) Expansion 2027	Run the Business		$155,000	$155,000
	Enterprise Content Management (ECM) Application Upgrade	Run the Business	$185,808		$185,808
	Enterprise Content Management (ECM) Application Upgrade	Run the Business		$100,000	$100,000
	Enterprise Content Management (ECM) Features/Expansion	Run the Business	$40,000		$40,000
	Enterprise Content Management (ECM) Features/Expansion	Run the Business		$62,000	$62,000
	FME Application Upgrade 2026	Run the Business	$25,000		$25,000
	FME Application/Server Upgrade 2027	Run the Business		$60,000	$60,000
	Globalscape Upgrade 2026	Run the Business	$50,000		$50,000
	Globalscape Upgrade 2027	Run the Business		$120,000	$120,000
	Intranet Features/Expansion 2026	Run the Business	$50,000		$50,000
	Intranet Features/Expansion 2027	Run the Business		$50,000	$50,000
	IT Service Management (ITSM) Expansion 2026	Grow the Business	$498,879	$1,121	$500,000
	IT Service Management (ITSM) Expansion 2027	Grow the Business		$499,103	$499,103
	Java AMC Upgrade 2026	Run the Business	$41,785		$41,785
	Java AMC Upgrade 2027	Run the Business		$45,000	$45,000
	Minor Application Purchases and Licenses - 2027	Run the Business		$80,000	$80,000
	Minor Application Purchases and Licenses -2026	Run the Business	$75,000		$75,000
	Mulesoft/API License Renewal 2026	Run the Business	$580,000		$580,000
	Non Production Development Environment	Run the Business		$350,000	$350,000
	Tableau Creator Upgrade 2026	Run the Business	$13,000		$13,000
	Tableau Creator Upgrade 2027	Run the Business		$14,000	$14,000
	Tableau License Renewal 2027	Run the Business		$275,000	$275,000
	Vuetify Upgrades 2026	Run the Business	$50,000		$50,000
	Vuetify Upgrades 2027	Run the Business		$50,000	$50,000
	Total		$3,490,216	$2,659,704	$6,149,919

Decision Log 2022 (for Governance Team)

Month	Decision Needed	Action	Approval
January	ECM Enhancements – Push to start Q3 and remove 85k from forecast	Push out ECM Enhancements and remove Q1/Q2 Costs as there is currently no GAD capacity	Approved - January 2022
February	SharePoint Upgrade – add to ETMOE	Add to ETMOE for Upgrade, then MPU?	Tentative
March	ECM Enhancements – add back in?	Needs Governance approval (Stakeholders approved)	Approved
April	Add ITSM to ETMOE?	Should we add ITSM to ETMOE BC?	Approved prelim.
May	Confirm ITSM approval and CPG funding request	Confirm ITSM approval and CPG funding request $, if so.	Approved
June	CPG funding not approved in June		Approved
July	Request ITSM at CPG?	Request was submitted and approved at July CPG. Additional 360k added to allocation.	Approved
August	NA		NA
September	ITSM - return to CPG	Not releasing funds to CPG	NA
October	NA		NA
November	Release $ to CPG	Released 200k to CPG	Approved
December	Approve Acrobat License Purchase		Approved

Decision Log 2023 (for Governance Team)

Month	Decision Needed	Action	Approval
January	2023 Governance	Is the current Governance Team accurate for 2023?	

Questions?

Thank you!

AVISTA

ETMOE Team


Jim Kensok
Hossein Nikdel
Jim Corder
Clay Storey
Nolan Steiner
ET Modernization and Operational Efficiency Governance Team
Karen Schuh (BC Owner)
Leianne Raymond (PgM)
Angela Moffat
Mike Mudge
Graham Smith
Brian Hoerner
Erica Ellis
Matt Reding
Jason Pitts
Brandon Naccarato
Debbie Butler
Parker Keegan
ET Modernization and Operational Efficiency Stakeholder Team

Cognos licensing summary – for reference

Reduction Opportunity - Cognos licensing

Plut, David
To Webster, Jeremiah; Munson, Adam
Cc Mudge, Mike; Raymond, Leianne; Bradley, Ryan
Retention Policy 3 Year Deletion (3 years) Expires 12/14/2025
This message was sent with High importance.

DXC SOW No 4 Cognos - Lics only.docx 52 KB
BUDGET IMPACT - DXC SOW No 4 Cognos Term Lic.xlsx 57 KB

Jeremiah, Adam,

Here is our 2nd time sensitive unplanned opportunity. ET has just identified a reduction opportunity that would need to be acted on / executed by 12/21.

Summary: move from maintenance and support of current perpetual licenses through IBM to term license through another vendor (DXC)
Reduction:

- 30% overall cost reduction to Avista (20% reduction using NPV) over the next 5 years (assumes only a 3% annual increase from IBM, though the 2022 increase was 10%).
- $40k overall expense reduction in 2023 (depreciation expense / A09)
- $160k reduction to A09 in 2023

Capital required: $486k

- As noted, we need to purchase by 12/21. The term begins 1/1/2023.
- We could directly charge capital for $486k in 2022 or charge the prepaid GL and charge capital in 2023
- Copying Leianne Raymond as she is aware of roughly this amount of capital in various ET business cases we are expected to be under in 2022 at this point.

Please let us know if the capital is available in 2022 or 2023 and if you are able to assist us with navigating any CPG requirements.

Thank you,
--David

David Plut, Manager - ET Finance
1411 E Mission Ave MSC-8, Spokane, WA, 99202
P 509.495.7588 | **F** 509.777.5672
www.myavista.com

Visual Studio Detail (for reference)

Hi Leianne,
The capital charges for Visual Studio had changed from 38%/62% capital/O&M split to 80/20 split which is why you are seeing additional charges. I apologize for notifying you, not realizing the impact to your capital spend. The yellow charges are accurate.
The 38%/62% split was from years ago and we did not feel comfortable using that split when our policy is to use 80/20 for software contracts that have the license, S&M lumped together.

Project	Task	Expnd Typ	Item Date	Employee	PO Numb	Invoice Number	Quantity	UOM	Proj Func Bu	Comment
9907126	107632	618 Softw	10/11/2022	MICROSOI	149490	9881521870	31738.09	Currency	31,738.09	1) CDW: SCE - Direct Server and Cloud Enrollment 10/1/22 - 9/30/2
9907126	107632	618 Softw	10/11/2022	MICROSOFT CORPOF		9881521870	2856.43	Currency	2,856.43	SALES TAX
9907126	107632	505 Capita	10/11/2022	MICROSOFT CORPORATION			0	Currency	34.60	
9907126	107632	618 Softw	11/30/2022				103783.6	Currency	103,783.55	Visual Studio 3 yr agreement through Microsoft/CDW
9907126	107632	505 Capita	11/30/2022				0	Currency	103.78	
9907126	107632	618 Softw	10/11/2022	MICROSOFT CORPOF		9881521870	-34594.5	Currency	(34,594.52)	DIST CORRECTION
9907126	107632	505 Capita	10/11/2022	MICROSOFT CORPORATION			0	Currency	(34.59)	
9907126	107632	618 Softw	12/31/2022				114708.1	Currency	114,708.10	Visual Studio 3 yr agreement through Microsoft/CDW adjusted spl
9907126	107632	505 Capita	12/31/2022				0	Currency	114.71	

Let me know if you have questions.
Tiffany

ET Modernization & Operational Efficiency (ETMOE) Governance Meeting

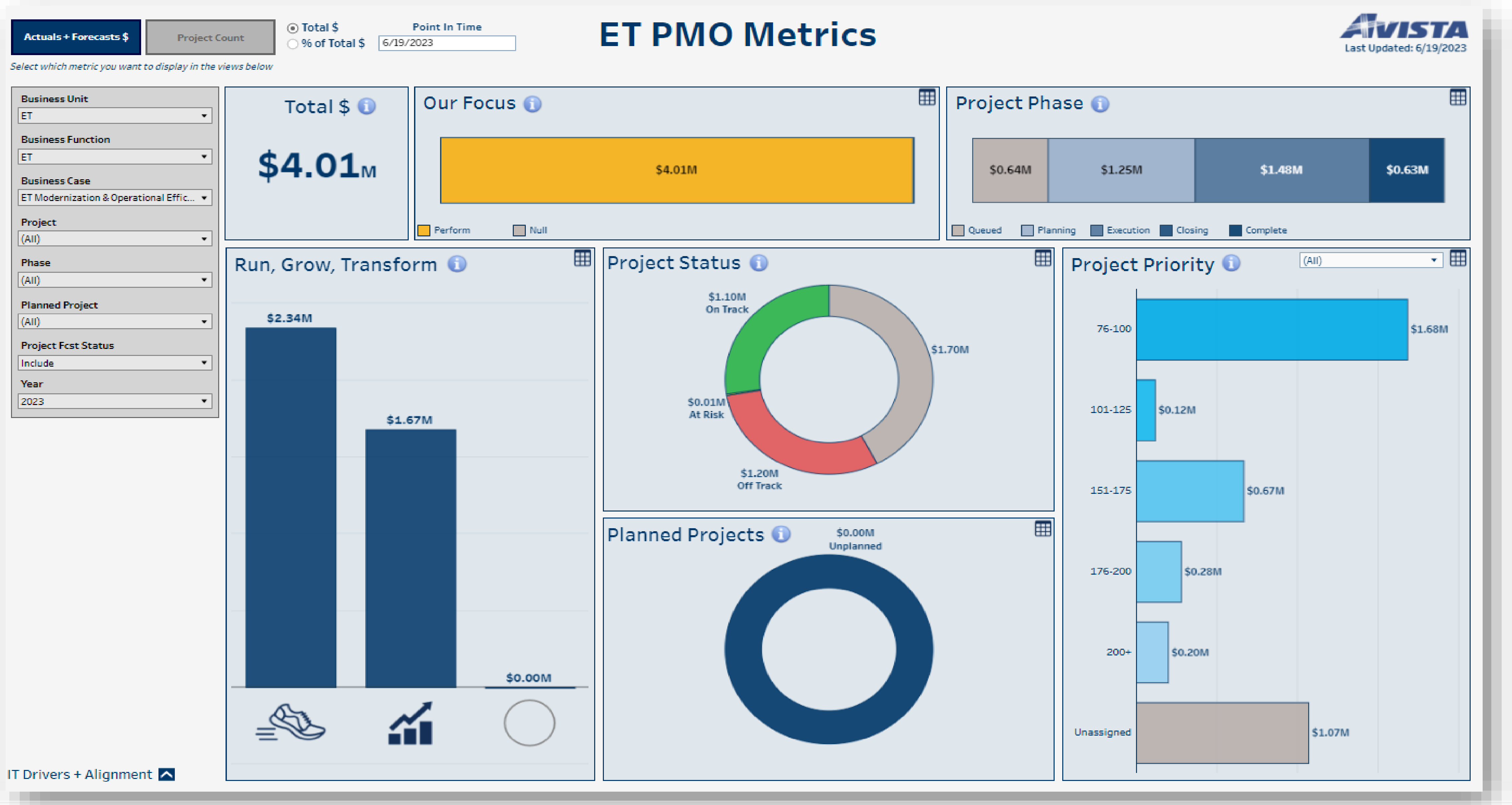
June 2023

Karen Schuh – Business Case Owner
Leianne Raymond – Program Manager

Agenda

- Business Case Metrics
- 2023 Financials
- 2023 Variance
- ETMOE Project Status / Headlines
- 2023 TTP
- 2023 Overview / TTP
- Five Year Overview
- Decisions / Decision Ledger

Business Case Metrics Dashboard - $



[ET PMO Metrics - WIP: PMO Metrics Dashboard ($) - Tableau Server (corp.com)]

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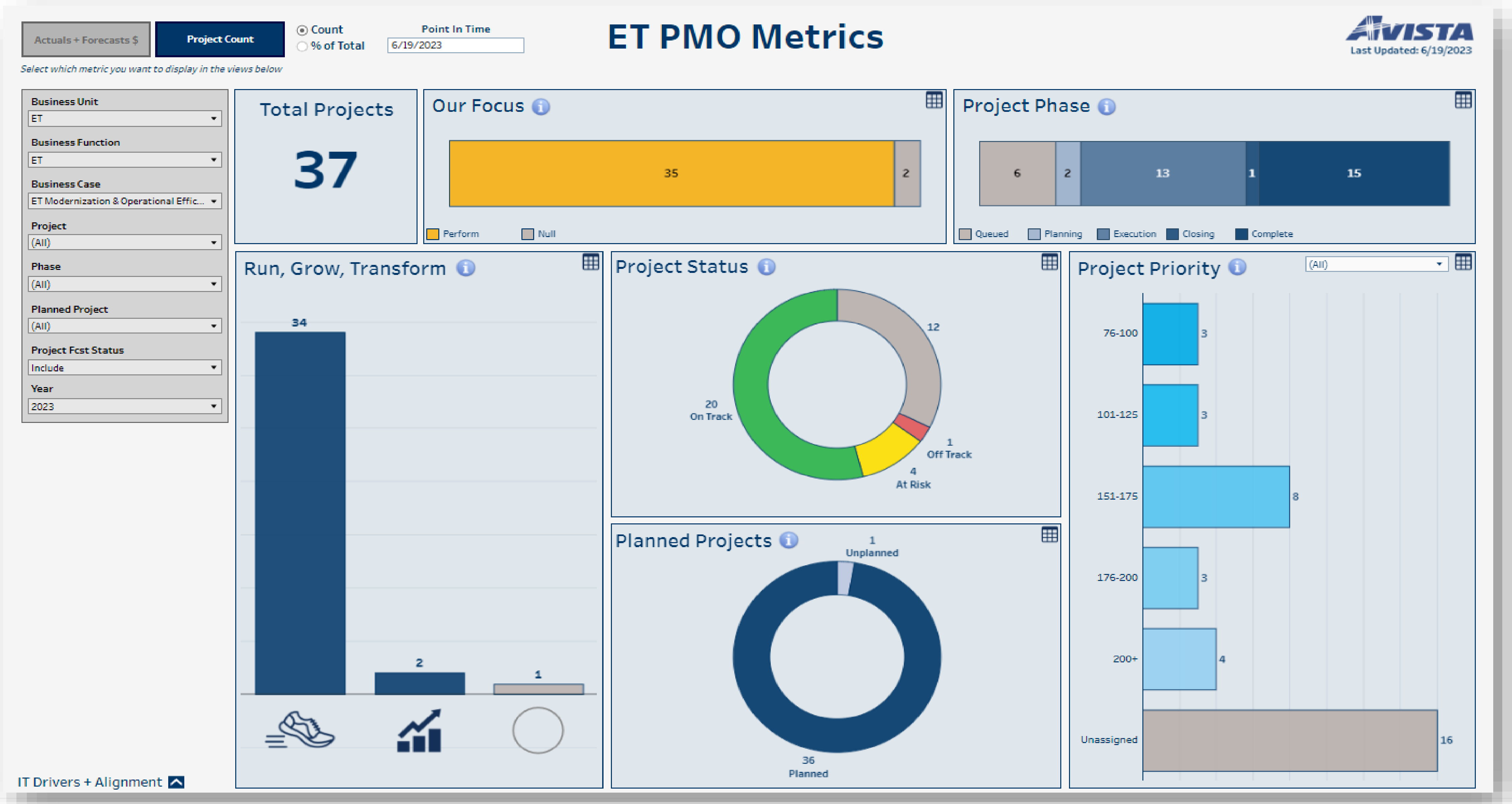
Business Case Metrics Dashboard - Project



[ET PMO Metrics - WIP: PMO Metrics Dashboard (Project) - Tableau Server (corp.com)]

Business Case Financial Summary

Actuals through: 05/31/23

Current Month

Current or Previous Year? Current

2023 Business Case Financials

Business Case	CPG Approval	YTD Actual Spend	Forecast	Exp. Annual Spend	Variance	% CPG Apprv. Spent
ET Modernization & Operational Efficiency -	$3,800,000	$1,272,044	$2,738,087	$4,010,131	($210,131)	33.47%
Grand Total	**$3,800,000**	**$1,272,044**	**$2,738,087**	**$4,010,131**	**($210,131)**	**33.47%**

Prior Month

Current or Previous Year? Current

2023 Business Case Financials

Business Case	CPG Approval	YTD Actual Spend	Forecast	Exp. Annual Spend	Variance	% CPG Apprv. Spent
ET Modernization & Operational Efficiency -	$3,800,000	$1,113,382	$2,912,420	$4,025,802	($225,802)	29.30%
Grand Total	**$3,800,000**	**$1,113,382**	**$2,912,420**	**$4,025,802**	**($225,802)**	**29.30%**

[ET and Security Portfolio Dashboard: BC Financials Blow-Up - Tableau Server (corp.com)]

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Financials by Quarter

Attachment C

Project	Phase	Actual 2023 Q1	Actual 2023 Q2	Forecast 2023 Q2	Forecast 2023 Q3	Forecast 2023 Q4	Grand Total
Tableau Creator Upgrade 2023	Queued				$4,323	$5,677	$10,000
Java AMC Upgrade 2023	Queued				$18,448	$21,552	$40,000
ITSM - Phase 2	Queued				$114,819	$355,937	$470,756
ECM Application Upgrade 2023 / 2024	Queued					$25,709	$25,709
BI / ETL Expansion 2023 Pkg. #2 - 09907189	Queued				$37,240	$37,760	$75,000
Adobe Standard and Pro Upgrade	Queued			$7,676	$10,252	$603	$18,531
ITSM Implementation Phase 1: IT Asset Management (ITAM) -..	Planning	$109,477	$67,855	$55,889	$508,300	$460,583	$1,202,105
Globalscape Upgrade 2023 - 09907234	Planning		$2,855	$16,674	$17,269	$13,405	$50,203
Vuetify Upgrade 2023 - 09907209	Execution	$36,257	$17,284	$33,426	$33,463	$769	$121,199
Mulesoft/API License Renewal 2023 - 09907243	Execution			$435,000			$435,000
Intranet Expansion 2023 - 09907187	Execution	$13,017	$6,169	$6,725	$12,616	$14,869	$53,395
FME Application/Server Upgrade 2023 - 09907250	Execution		$830	$8,336	$21,424	$14,260	$44,851
ECM Expansion 2023 - 09907184	Execution	$20,336	$8,970	$3,157	$8,180	$10,630	$51,273
DAAP Expansion 2023 - 09907185	Execution	$65,140	$14,733	$18,047	$43,291	$36,806	$178,016
Cognos Upgrade 2022 - 09907034	Execution	$52,657	$28,497	$9,376	$8,031		$98,562
BI / ETL Expansion 2023 Pkg. #1 - 09907188	Execution	$38,133	$35,274	$28,234			$101,641
Azure DevOps Upgrade - 09907165	Execution	$34,915	$23,879	$56,570	$97,170	$1,357	$213,892
Azure DevOps Expansion 2023 - 09907192	Execution	$974	$76	$1,114	$27,138	$18,413	$47,715
App Dynamics Expansion 2023 - 09907186	Execution	$14,349	$6,973	$5,757	$12,955	$15,375	$55,409
Alation Upgrade 2023 - 09907233	Execution		$3,056	$5,062	$2,494		$10,612
API Management Tool Expansion 2023 - 09907179	Execution	$12,077	$24,744	$12,464	$19,001	$1,027	$69,313
Intranet Features/Expansion 2022 - 09906995	Complete	$7					$7
Globalscape Upgrade 2022 - 09907006	Complete	$51					$51
ECM Features/Expansion 2022 - 09907043	Complete	($438)					($438)
Devolutions: Remote Desktop Manager Enterprise (3 yr. rene..	Complete	$1					$1
Bluebeam ReVu License and Packaging - 09906868	Complete	($5,388)					($5,388)
BI / ETL Expansion 2022 Pkg. #2 - 09906991	Complete	$3,775	$2,344				$6,119
BI / ETL Expansion 2022 Pkg. #1 - 09906990	Complete	$0	$92	$1,656			$1,748
Azure DevOps Features/Expansion 2022 - 09906997	Complete	$3,724					$3,724
App Dynamics License Renewal - 09907207	Complete	$622,942					$622,942
App Dynamics Expansion 2022 - 09906992	Complete	$377	$422	$594			$1,393
Alation Upgrade 2022 - 09907015	Complete	$79					$79
API Management Expansion 2022 - 09907068	Complete	($1,629)					($1,629)
DAAP Expansion 2022 - 09906994	Closing	$2,878	$4,277	$1,184			$8,339
Total		**$1,023,714**	**$248,331**	**$706,941**	**$996,414**	**$1,034,731**	**$4,010,131**
		$1,023,714	$248,331	$706,941	$996,414	$1,034,731	$4,010,131

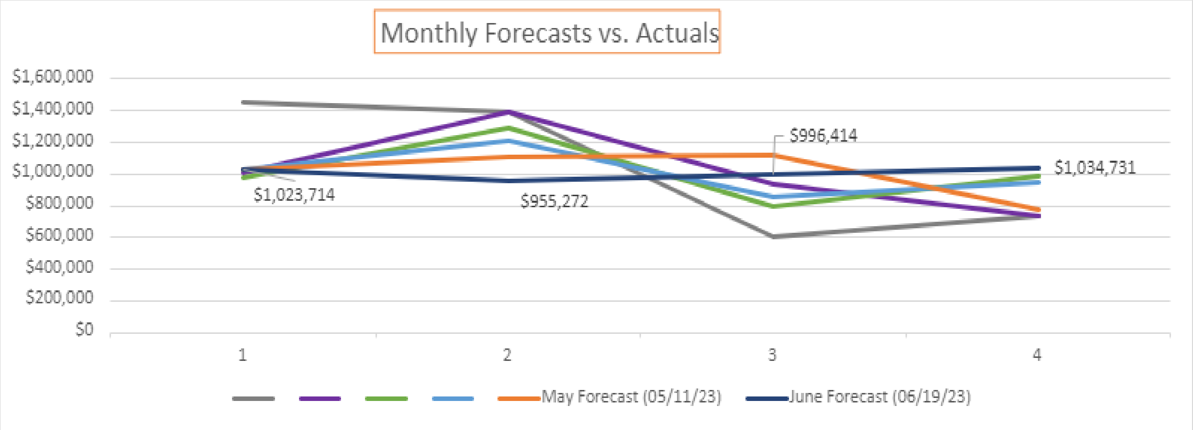
ET and Security Portfolio Dashboard: Project Actuals/Forecasts Blow-Up - Tableau Server (corp.com)

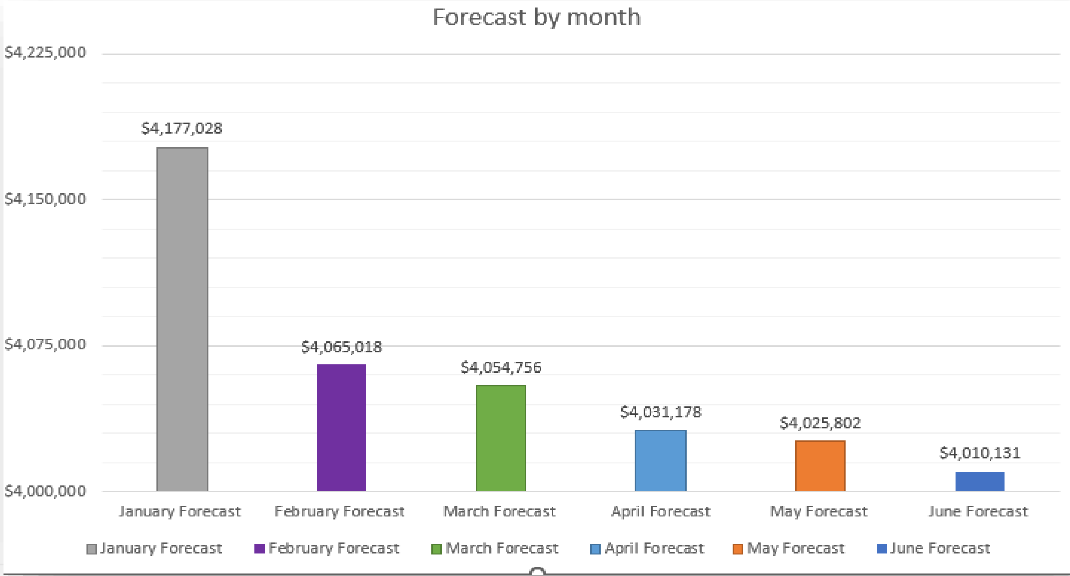
Forecast Variance

Quarterly Forecast variances

Quarter	January Forecast (1/18/23)	February Forecast (02/15/23)	March Forecast (03/15/23)	April Forecast (04/12/23)	May Forecast (05/11/23)	June Forecast (06/19/23)
Q1	$1,448,673	$1,004,530	$978,116	$1,023,714	$1,023,714	$1,023,714
Q2	$1,394,359	$1,388,517	$1,293,780	$1,206,601	$1,105,071	$955,272
Q3	$603,143	$937,071	$796,217	$858,149	$1,123,624	$996,414
Q4	$730,853	$734,900	$986,643	$942,715	$773,393	$1,034,731
Total	$4,177,028	$4,065,018	$4,054,756	$4,031,178	$4,025,802	$4,010,131

Quarterly Actuals	
Forecast	





Attachment C

Project Variance by Month

Phase	Project	May Project Total Forecast	June Project Total Forecast	Forecast Variance from prior month
Complete	Alation Upgrade 2022	$79	$79	$0
Complete	API Management Expansion 2022 - 09907068	($1,629)	($1,629)	$0
Complete	App Dynamics License Renewal - 09907207	$622,942	$622,942	$0
Complete	Azure DevOps Expansion 2022 - 09906997	$3,724	$3,724	$0
Complete	BI / ETL Expansion 2022 Pkg. #1 - 09906990	$0	$1,748	$1,748
Complete	BI / ETL Expansion 2022 Pkg. #2 - 09906991	$5,164	$6,119	$955
Complete	Bluebeam Revu Licensing	($5,388)	($5,388)	$0
Complete	Devolution Remote Desktop Manager	$1	$1	$0
Complete	Globalscape Upgrade 2022	$51	$51	$0
Complete	Intranet Features/Expansion 2022 - 09906995	$7	$7	$0
Complete	App Dynamics Expansion 2022 - 09906992	$1,851	$1,393	($458)
Complete	ECM Features/Expansion 2022 - 09907043	$746	($438)	($1,184)
Closing	DAAP Expansion 2022 - 09906994	$7,442	$8,339	$897
Execution	API Management Tool Expansion 2023 - 09907179	$92,987	$69,313	($23,674)
Execution	Alation Upgrade 2023	$11,132	$10,612	($520)
Execution	App Dynamics Expansion 2023 - 09907186	$55,294	$55,409	$115
Execution	Azure DevOps Expansion 2023 - 09907192	$48,730	$47,715	($1,015)
Execution	Azure DevOps Upgrade - 09907165	$208,212	$213,892	$5,680
Execution	BI / ETL Expansion 2023 Pkg. #1 - 09907188	$103,961	$101,641	($2,320)
Execution	Cognos Upgrade 2022 - 09907034	$98,429	$98,562	$133
Execution	DAAP Expansion 2023 - 09907185	$178,125	$178,016	($109)
Execution	ECM Expansion 2023 - 09907184	$51,455	$51,273	($182)
Execution	FME Application/Server Upgrade 2023	$45,000	$44,851	($149)
Execution	Intranet Expansion 2023 - 09907187	$50,502	$53,395	$2,893
Execution	Mulesoft/API License Renewal 2023	$435,000	$435,000	$0
Execution	Vuetify Upgrade 2023 - 09907209	$126,130	$121,199	($4,931)
Planning	Globalscape Upgrade 2023	$40,529	$50,203	$9,674
Planning	ITSM Implementation Phase 1 - 09907141	$1,199,496	$1,202,105	$2,609
Queued	Adobe Standard and Pro Upgrade	$24,364	$18,531	($5,833)
Queued	BI / ETL Expansion 2023 Pkg. #2 - 09907189	$75,000	$75,000	$0
Queued	ECM Application Upgrade 2023 / 2024	$25,709	$25,709	$0
Queued	ITSM Implementation - Phase 2	$470,756	$470,756	$0
Queued	Java AMC Upgrade 2023	$40,000	$40,000	$0
Queued	Software Composition Analysis (SCA)	$0	$0	$0
Queued	Tableau Creator Upgrade 2023	$10,000	$10,000	$0
		$4,025,801	$4,010,131	($15,670)

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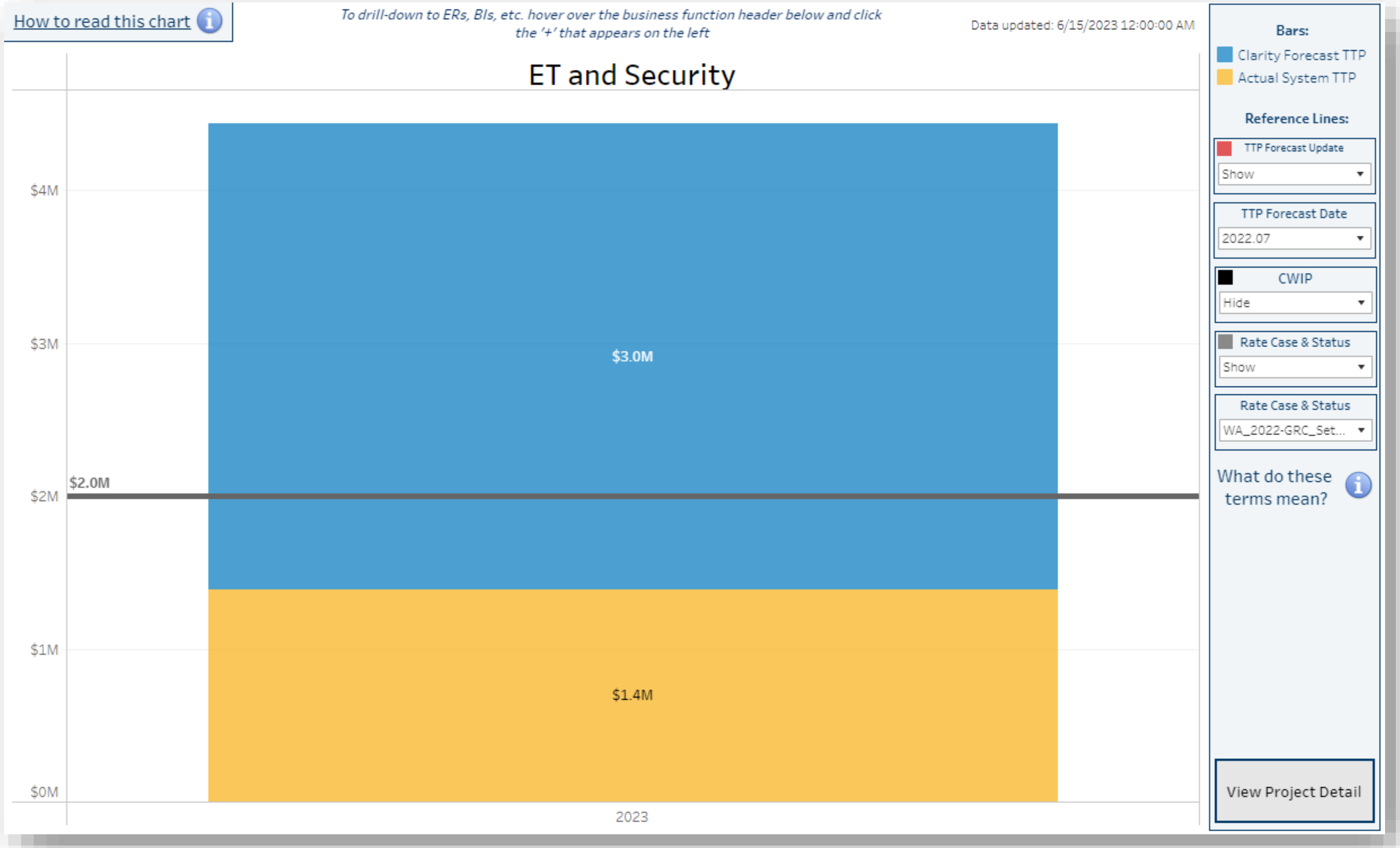
Transfer to Plant (TTP) forecast



GRC TTP = 2M
Forecast TTP = 4.4M

Cognos Licensing
Acrobat Licensing
Tableau License Renewal
Cognos Upgrade
Vuetify upgrade
ITSM

Transfer to Plant (TTP) by Project

Project	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Acrobat Licenses -2022 (3 year	$162,714												$162,714
Adobe Standard and Pro Upgrade							$13,084	$3,018	$1,826	$603			$18,531
Alation Upgrade 2022 - 09907015	$79												$79
Alation Upgrade 2023 - 09907233							$9,816	$796					$10,612
API Management Expansion 2022 - 0..	($2,704)	$49	$1,026										($1,629)
API Management Tool Expansion 20..												$69,313	$69,313
App Dynamics Expansion 2022 - 099..	$4	$374		$422		$594							$1,393
App Dynamics Expansion 2023 - 099..												$55,409	$55,409
App Dynamics License Renewal - 099..			$622,942										$622,942
Azure DevOps Expansion 2023 - 099..												$47,715	$47,715
Azure DevOps Features/Expansion 2..	$343	$2,167	$1,213										$3,724
Azure DevOps Upgrade - 09907165						$170,238	$62,001	$29,799	$5,371	$1,357			$268,766
BI / ETL Expansion 2022 Pkg. #1 - 09..		$0			$92	$1,656							$1,748
BI / ETL Expansion 2022 Pkg. #2 - 09..	$1,848	$779	$1,149	$462	$1,882								$6,119
BI / ETL Expansion 2023 Pkg. #1 - 09..						$101,641							$101,641
BI / ETL Expansion 2023 Pkg. #2 - 09..												$75,000	$75,000
Cognos Licensing (5 Year term) - 099..	$463,969												$463,969
Cognos Upgrade 2022 - 09907034						$172,920	$5,560	$2,471					$180,951
DAAP Expansion 2022 - 09906994	($2,989)	$3,637	$2,230	$3,380	$896	$1,184							$8,339
DAAP Expansion 2023 - 09907185												$178,016	$178,016
Devolutions: Remote Desktop Mana..	$1												$1
ECM Expansion 2023 - 09907184												$51,273	$51,273
ECM Features/Expansion 2022 - 099..	($1,372)	$846	$88										($438)
FME Application/Server Upgrade 20..										$37,697	$4,577	$2,576	$44,851
Globalscape Upgrade 2022 - 099070..	$51												$51
Globalscape Upgrade 2023 - 099072..												$50,203	$50,203
Intranet Expansion 2023 - 09907187												$53,395	$53,395
Intranet Features/Expansion 2022 - ..	($105)	$112											$7
ITSM Implementation Phase 1: IT As..												$1,234,729	$1,234,729
Java AMC Upgrade 2023											$32,796	$7,204	$40,000
Mulesoft/API License Renewal 2023 ..						$435,000							$435,000
Tableau Creator Upgrade 2023											$8,735	$1,266	$10,000
Tableau License Renewal 2022 - 099..	$122,726												$122,726
Vuetify Upgrade 2023 - 09907209								$110,550	$9,880	$769			$121,199
	$744,564	$7,964	$628,649	$4,264	$2,871	$883,233	$90,460	$146,633	$17,077	$40,427	$46,108	$1,826,099	$4,438,350

Project Headlines

HEADLINES

$210,000 over budget (forecast)

Queued projects

- ITSM Phase 2: **$470,000**
- Adobe Upgrade: $18,500
- Java AMC Upgrade: $40,000
- ECM Upgrade: $25,700
- Tableau Upgrade: $10,000

New Project requests

- Splunk Licensing (pending more info):

  "…change how we're funding the IS Ops Splunk entitlement and bolster the licensing a bit for CX support. We've been funding entirely via OpEx in A09 for a few years but we'd like to co-term with security's purchase and move to a 3 year purchase so we can capitalize and ultimately spend less OpEx".

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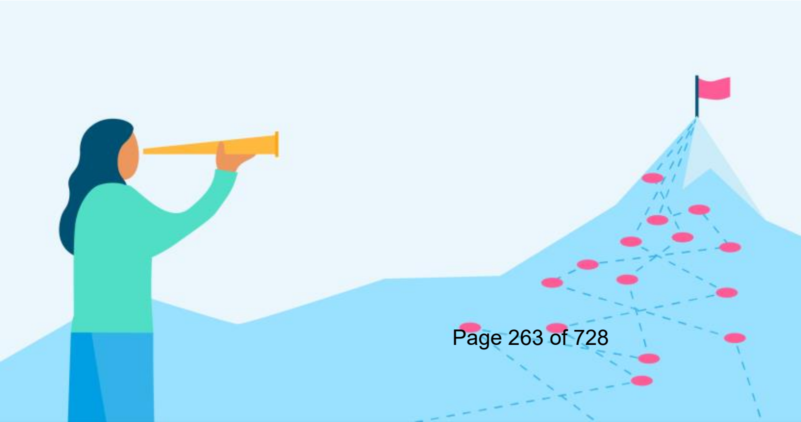
Five Year Plan (2024-2028)

Year	2023 Requested Amount	2022 CPG Approved Amount	*Variance (Requested vs. Approved)*	Current Forecast (Expected Spend)	Variance (CPG Approved vs. Expected Spend)	
2024	$3,618,000	**$2,350,000**	*($1,268,000)*	**$3,571,658**	($1,221,658)	ITSM Phase 3, FME Upgrade Tableau License Renewal (changed agreement) Clarity, ECM Upgrade
2025	$2,443,408	**$1,460,000**	*($983,408)*	**$2,343,409**	($883,409)	BizTalk Upgrade moved from 2023 to 2025/26
2026	$2,602,843	**$2,975,000**	*$372,157*	**$2,602,843**	$372,157	BizTalk Upgrade moved from 2023 to 2025/26
2027	$3,117,500	**$1,880,000**	*($1,237,500)*	**$3,117,501**	($1,237,501)	Non-Production Dev. Env
2028	$2,193,780	***TBD**	*TBD*	**$2,193,781**		
Total	$13,975,531	***$8,665,000**		**$13,829,193**	**($2,646,382)**	

*2028 approval not yet available



2024-2028 ETMOE Business Case Narrative: 2024-2028_ETMOE BCFR_Signed.pdf

2024 Projects

Business Case	Project	Goal	2024 Q1	2024 Q2	2024 Q3	2024 Q4	Grand Total
ET Modernization & Operational Efficiency - Technology	Alation Licenses 2024 - 2 Year agreement	Run the Business				$88,000	$88,000
	Alation Upgrade 2024	Run the Business	$1,374	$8,626			$10,000
	API Management Expansion 2024	Run the Business	$6,677	$18,258	$24,242	$5,822	$55,000
	App Dynamics Expansion 2024	Run the Business	$10,031	$12,982	$13,160	$13,828	$50,000
	Azure DevOps Features/Expansion 2024	Run the Business	$11,675	$10,613	$10,771	$6,940	$40,000
	Azure DevOps Upgrade 2024	Run the Business		$16,851	$24,511	$8,638	$50,000
	BI / ETL Expansion 2024	Run the Business	$90,394	$91,684	$91,684	$76,237	$350,000
	Clarity Application Upgrade (SaaS or Rep.) 2024	Run the Business	$199,696	$302,829	$97,475		$600,000
	Cognos Upgrade 2024	Run the Business			$28,056	$41,944	$70,000
	DAAP Expansion 2024	Run the Business	$25,507	$35,520	$38,439	$50,534	$150,000
	ECM Application Upgrade 2023 / 2024	Run the Business	$83,663	$90,628			$174,291
	ECM Expansion 2024	Run the Business	$5,587	$14,739	$13,740	$15,934	$50,000
	FME Application Upgrade 2024	Run the Business		$5,430	$16,959	$2,610	$25,000
	FME Application/Server Upgrade 2023 - 09907250	Run the Business	$28				$28
	Globalscape Upgrade 2023 - 09907234	Run the Business	$5,094				$5,094
	Globalscape Upgrade 2024	Run the Business	$15,985	$27,172	$27,172	$4,670	$75,000
	Intranet Features/Expansion 2024	Run the Business	$13,000	$13,201	$13,403	$10,396	$50,000
	IT Service Management (ITSM) Implementation - Phase 3	Grow the Business		($21,651)	$169,985	$151,665	$300,000
	ITSM - Phase 2	Grow the Business	$395,314	$341,579	$7,351		$744,244
	Java AMC Upgrade 2024	Run the Business		$18,665	$18,953	$2,382	$40,000
	Minor Application Purchases and Licenses -2024	Run the Business	$11,500	$17,059	$16,817	$14,624	$60,000
	Software Composition Analysis (SCA)	Run the Business	$64,615	$101,053	$101,053	$8,279	$275,000
	Tableau Creator Upgrade 2024	Run the Business	$919	$5,347	$3,734		$10,000
	Tableau License Renewal 2024 (with SalesForce renewal)	Run the Business		$250,000			$250,000
	Vuetify Upgrades 2024	Run the Business	$10,756	$13,972	$14,187	$11,086	$50,000
	Total		$951,815	$1,374,559	$731,694	$513,591	$3,571,658

2025 Projects

Business Case	Project	Goal	2025 Q1	2025 Q2	2025 Q3	2025 Q4	Grand Total
ET Modernization & Operational Efficiency - Technology	Adobe Standard and Pro Upgrade 2025	Run the Business		$4,244	$18,035	$4,722	$27,000
	Alation Upgrade 2025	Run the Business	$205	$9,419	$1,377		$11,000
	API Management Expansion 2025	Run the Business	$7,923	$12,367	$16,560	$18,150	$55,000
	App Dynamics Expansion 2025	Run the Business	$10,138	$14,120	$14,252	$11,990	$50,500
	Azure DevOps Features/Expansion 2025	Run the Business	$8,939	$10,200	$10,528	$10,333	$40,000
	BI / ETL Expansion 2025	Run the Business	$90,004	$93,117	$94,550	$72,330	$350,000
	Cognos Upgrade 2025	Run the Business			$29,206	$20,794	$50,000
	DAAP Expansion 2025	Run the Business	$25,043	$35,361	$38,113	$51,483	$150,000
	Devolutions: Remote Desktop Manager Enterprise (3 year	Run the Business			$20,000		$20,000
	ECM Application Upgrade 2025 / 2026	Run the Business				$64,192	$64,192
	ECM Expansion 2025	Run the Business	$11,528	$12,137	$12,264	$9,072	$45,000
	FME Application Upgrade 2025	Run the Business		$6,673	$20,716	$2,610	$30,000
	Globalscape Upgrade 2025	Run the Business	$8,555	$32,273	$38,873	$20,299	$100,000
	Intranet Features/Expansion 2025	Run the Business	$12,789	$13,194	$13,395	$10,622	$50,000
	IT Service Management (ITSM) Expansion 2025	Grow the Business	$98,454	$134,574	$134,574	$132,397	$500,000
	IT Service Management (ITSM) Implementation - Phase 3	Grow the Business	$75,000				$75,000
	Java AMC Upgrade 2025	Run the Business		$3,145	$18,298	$19,557	$41,000
	Minor Application Purchases and Licenses -2025	Run the Business	$9,839	$12,995	$16,920	$19,962	$59,716
	Mulesoft/API License Renewal 2025	Run the Business		$448,000			$448,000
	Tableau Creator Upgrade 2025	Run the Business	$5,097	$7,903			$13,000
	Visual Studio License Renewal 2025	Run the Business				$114,000	$114,000
	Vuetify Upgrades 2025	Run the Business	$11,962	$13,692	$13,903	$10,443	$50,000
	Total		$375,475	$863,416	$511,564	$592,955	$2,343,409

2026/2027 Projects

Business Case	Project	Goal	2026 Q1	2026 Q2	2026 Q3	2026 Q4	Grand Total
ET Modernization & Operational Efficiency - Technology	Alation Licenses 2026 -2 Year agreement	Run the Business				$90,000	$90,000
	Alation Upgrade 2026	Run the Business	$362	$10,308	$1,330		$12,000
	API Management Expansion 2026	Run the Business	$10,051	$15,000	$11,815	$13,135	$50,000
	App Dynamics Expansion 2026	Run the Business	$5,263	$10,597	$12,168	$22,222	$50,250
	App Dynamics Licensing 2026	Run the Business	$650,000				$650,000
	Azure DevOps Features/Expansion 2026	Run the Business	$6,552	$9,645	$14,698	$9,104	$40,000
	Azure DevOps Upgrade 2026	Run the Business	$4,596	$24,894	$20,510		$50,000
	BI / ETL Expansion 2026	Run the Business	$76,947	$93,117	$94,550	$85,386	$350,000
	Clarity Application Upgrade 2026	Run the Business		$24,990	$31,049	$23,961	$80,000
	Cognos Upgrade 2026	Run the Business			$21,886	$28,114	$50,000
	DAAP Expansion 2026	Run the Business	$15,352	$55,376	$33,733	$45,539	$150,000
	ECM Application Upgrade 2025 / 2026	Run the Business	$90,444	$95,363			$185,808
	ECM Expansion 2026	Run the Business	$8,327	$11,696	$11,620	$8,358	$40,000
	FME Application Upgrade 2026	Run the Business		$5,682	$16,783	$2,535	$25,000
	Globalscape Upgrade 2026	Run the Business	$3,486	$10,300	$10,458	$25,756	$50,000
	Intranet Features/Expansion 2026	Run the Business	$7,290	$13,220	$15,128	$14,363	$50,000
	IT Service Management (ITSM) Expansion 2026	Grow the Business	$80,921	$139,571	$189,886	$89,623	$500,000
	Java AMC Upgrade 2026	Run the Business		$9,934	$21,855	$9,996	$41,785
	Minor Application Purchases and Licenses -2026	Run the Business	$17,928	$18,379	$18,661	$20,032	$75,000
	Tableau Creator Upgrade 2026	Run the Business	$6,419	$6,581			$13,000
	Vuetify Upgrades 2026	Run the Business	$12,570	$13,008	$13,001	$11,421	$50,000
	Total		$996,507	$567,660	$539,131	$499,545	$2,602,843

Business Case	Project	Goal	2027 Q1	2027 Q2	2027 Q3	2027 Q4	Grand Total
ET Modernization & Operational Efficiency - Technology	Acrobat License Renewal (3 year term)	Run the Business				$120,000	$120,000
	Adobe Standard and Pro Upgrade 2027	Run the Business		$4,652	$18,531	$5,317	$28,500
	Alation Upgrade 2027	Run the Business	$1,809	$16,191			$18,000
	API Management Expansion 2027	Run the Business	$17,029	$24,068	$12,964	$8,439	$62,500
	App Dynamics Expansion 2027	Run the Business	$11,674	$14,031	$14,506	$10,289	$50,500
	Azure DevOps Features/Expansion 2027	Run the Business	$8,119	$14,448	$12,490	$4,943	$40,000
	BI / ETL Expansion 2027	Run the Business	$36,501	$37,926	$38,463	$37,111	$150,000
	Cognos Licensing (5 Year term)	Null				$535,000	$535,000
	Cognos Upgrade 2027	Run the Business		$14,151	$42,002	$18,847	$75,000
	DAAP Expansion 2027	Run the Business	$26,798	$46,942	$41,333	$39,928	$155,000
	ECM Expansion 2027	Run the Business	$18,215	$17,226	$16,384	$10,176	$62,000
	ECM Upgrade 2027 / 2028	Run the Business				$100,000	$100,000
	FME Application/Server Upgrade 2027	Run the Business		$42,618	$17,383		$60,000
	Globalscape Upgrade 2027	Run the Business	$15,806	$44,669	$45,356	$14,169	$120,000
	Intranet Features/Expansion 2027	Run the Business	$9,918	$14,195	$12,881	$13,006	$50,000
	IT Service Management (ITSM) Expansion 2027	Grow the Business	$96,708	$145,021	$151,909	$106,362	$500,000
	Java AMC Upgrade 2027	Run the Business		$6,605	$18,953	$19,443	$45,000
	Minor Application Purchases and Licenses -2027	Run the Business	$16,447	$19,704	$22,262	$21,587	$80,000
	Mulesoft/API License Renewal 2027	Run the Business		$452,000			$452,000
	Non Production Development Environment	Run the Business	$17,689	$104,526	$106,134	$121,652	$350,000
	Tableau Creator Upgrade 2027	Run the Business		$8,576	$5,424		$14,000
	Vuetify Upgrades 2027	Run the Business	$12,420	$13,008	$13,208	$11,365	$50,000
	Total		$289,132	$1,040,556	$590,181	$1,197,632	$3,117,501

2028 Projects

Business Case	Project	Goal	2028 Q1	2028 Q2	2028 Q3	2028 Q4	Grand Total
ET Modernization & Operational Efficiency - Technology	Alation Licenses 2028 -2 Year agreement	Run the Business				$96,000	$96,000
	Alation Upgrade 2028	Run the Business	$1,845	$10,155			$12,000
	API Management Expansion 2028	Run the Business	$12,833	$12,833	$12,833	$16,502	$55,000
	App Dynamics Expansion 2028	Run the Business	$11,145	$14,318	$14,575	$10,963	$51,000
	Azure DevOps Features/Expansion 2028	Run the Business	$6,936	$14,408	$19,237	$14,419	$55,000
	Azure DevOps Upgrade 2028	Run the Business	$25,339	$37,433	$12,229		$75,000
	BI / ETL Expansion 2028	Run the Business	$31,612	$39,834	$39,783	$38,772	$150,000
	Clarity Application Upgrade 2028	Run the Business	$1,915	$24,712	$24,793	$33,580	$85,000
	Cognos Upgrade 2028	Run the Business			$55,102	$24,898	$80,000
	DAAP Expansion 2028	Run the Business	$15,515	$38,375	$44,436	$51,674	$150,000
	Devolutions: Remote Desktop Manager Enterprise (3 year	Run the Business			$22,000		$22,000
	ECM Expansion 2028	Run the Business	$9,751	$14,622	$14,622	$11,005	$50,000
	ECM Upgrade 2027 / 2028	Run the Business	$207,528	$132,473			$340,000
	FME Application Upgrade 2028	Run the Business		$23,279	$11,721		$35,000
	Globalscape Upgrade 2028	Run the Business	$1,102	$37,612	$38,934	$22,353	$100,000
	Intranet Features/Expansion 2028	Run the Business	$8,282	$13,139	$13,475	$15,103	$50,000
	IT Service Management (ITSM) Expansion 2028	Grow the Business	$98,903	$148,191	$152,946	$99,960	$500,000
	Java AMC Upgrade 2028	Run the Business		$18,666	$18,666	$2,669	$40,000
	Minor Application Purchases and Licenses -2028	Run the Business	$10,697	$18,194	$18,194	$17,914	$65,000
	Tableau Creator Upgrade 2028	Run the Business		$3,770	$6,807	$3,924	$14,500
	Visual Studio License Renewal 2028	Run the Business				$116,280	$116,280
	Vuetify Upgrades 2028	Run the Business	$11,028	$13,268	$13,268	$14,437	$52,000
	Total		$454,429	$615,280	$533,619	$590,452	$2,193,781

Decision Log 2023
(for Governance Team)

Month	Decision Needed	Action	Approval
January	Is there an option to reduce 280k?	Select option/scenario or wait	No changes at this time until we have more data on a handful of projects
February	What will we do with the over budget allocation?	Select an option or wait for more information	No changes at this time until we have more data on specific projects
March	N/A		
April	SCA Move to 2024?	Keep in 2023 or move to 2024	Move to 2024
May			
June			
July			
August			
September			
October			
November			
December			

Questions?

Thank you!

ETMOE Team

Welcome, Wayne!


Wayne Manuel


Hossein Nikdel


Jim Corder


Clay Storey


Nolan Steiner

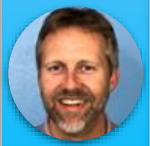
ET Modernization and Operational Efficiency Governance Team


Karen Schuh (BC Owner)


Leianne Raymond (PgM)

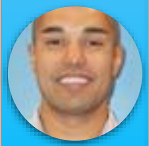

Angela Moffat


Mike Mudge


Graham Smith


Brian Hoerner

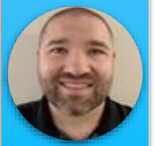

Erica Ellis


Matt Reding


Jason Pitts


Brandon Naccarato


Debbie Butler


Parker Keegan

ET Modernization and Operational Efficiency Stakeholder Team

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Fiber Network Lease Service Replacement (FNLSR)

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This business case is focused on transitioning Avista's control and safety network off of leased lines onto privately owned fiber optic cable. Avista utilizes leased fiber optic cable to transport primarily safety and control data between offices, substations, and generation facilities. The leased fiber incurs an operating expense with lease rates that were established during the sale of an Avista Communication's subsidiary.

For the tracking year of 2023, the Fiber Network Lease Service Replacement business case planned to transfer-to-plant $1,687,126 in project work, while actually transferring $2,876,485. This resulted in an over-transfer amount of $1,189,359.

The main driver of this variance was resource constraints tied to both our internal Avista engineering teams along with constraints from our professional services construction partner in 2022 and adjustments to sequencing of work. These constraints compounded through 2022, resulting in project work pushed into 2023. The result of the changes caused the transfer for to plant amount for 2022 to be less than originally planned and increased the expected transfers in 2023.

The table below provides details of the shifts:

Project	Original Plan	Actual Result
Ross Park/Beacon Fiber Approach	$177,603	$230,395
Sunset to Downtown West	$411,669	$661,943
New Metro to 3rd and Hatch (pushed to 2025)	$225,162	$0
Southeast to Sunset (moved to future years)	$237,341	$0
3rd and Hatch to Morris Center Vault (pushed into 2024 for TTP)	$315,203	$0
Spokane Industrial Park to Boulder Park (moved to future years)	$205,300	$0
Huetter to Prairie	$0	$582,093
Idaho Rd to Prairie	$0	$599,514
Rathdrum CT to Avondale	$0	$675,354
Sunset to 9th & Central	$0	$116,184
Other Work	$114,848	$11,002
Totals	**$1,687,126**	**$2,876,485**

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. The following business case change requests and governance documents are attached with further details surrounding the above explanations.

- Change request dated August 2023 – Requested $1 million for:
    - An unplanned project brought forth by the Transmission group to install OPGW from Sunset to 9th & Central for approximately $225,000.
    - The 3rd & Hatch to Scott Morris Center project which had stalled prior to 2023 but became a priority in 2023 adding approximately $250,000 to the business case cost.
    - Changing prioritization caused schedules to push increasing resource and construction costs, increased AFUDC charges and added scope impacting projects which transferred to plant in 2023:
        - Rathdrum CT to Avondale - $150,000 increase
        - Ross Park and Beacon Approaches - $100,000 increase
        - Sunset to Downtown West - $215,000 increase
        - Other work - $60,000
    - This also raised the 2023 expected TTP amount by approximately $1 million.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The direct offsets associated with this business case relate to avoided annual lease costs. These lease costs will go away when this work is set to complete in 2027. Any significant delays will delay the offset that is anticipated in 2027 and potentially beyond.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Shawna Kiesbuy
3CD905A81B984C3...

DIRECTOR SIGNATURE:

X DocuSigned by: Alexis Alexander
EA27BABA767F467...

Fiber Network Lease Service Replacement

1.0 CHANGE REQUEST #01 – 2023.09.20

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
8/16/2023	*Scope Change*	01	$1,000,000	$1,000,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
8/16/2023	Scope Change	$0	$0	$1,700,000	$2,737,891
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Fiber Network Lease Service Replacement

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Fiber Network Leased Service Replacement Program Business Case is focused on transitioning Avista's control and safety network from leased lines onto privately owned fiber optic cable. For this business case, the project work identified 47 segments and a total of approximately 98 miles of leased fiber left to be replaced with Avista-owned private fiber. Sometimes those segments are replaced with Optical Ground Wire (OPGW). An optical ground wire (also known as an OPGW or, in the IEEE standard, an optical fiber composite overhead ground wire) is a type of cable that is used in overhead power lines. Such cable combines the functions of grounding and communications.[1]

In the business case this year, we have had multiple increases to projects which have increased the overall funding needed in 2023. To start, we moved planned work in 2024 back into 2023 to align with Transmissions' plans. The project is called Sunset to 9th & Central OPGW. This new project was brought to the Network team from the Transmission Group to offer us an opportunity to run OPGW on the segments which Transmission was going to be working on and would ultimately deliver the communications pathway needed for the same fiber segments we were planning to replace as part of this business case in the future. This project increases the planned spend in 2023 by approximately $225,000 which is a portion of the overall Transmission project cost.

In addition, we have a project, 3rd and Hatch to the Scott Morris Center, which was opened in February of 2020 but has only recently gained traction to start work by bringing in a construction crew this Fall. The renewed velocity on this project was unplanned and as such, is resulting in approximately $250,000 in spend this year. This project is a dependency for the new Metro Substation.

Lastly, we have seen increased costs for the following projects due to decreased prioritization pushing out schedules and increasing project support costs and AFUDC, external factors when working with city and towns to align construction work, added scope for redundancy, and increased construction costs higher than originally forecasted.

- Rathdrum CT to Avondale Fiber Replacement - $150,000 increase
- Ross Park and Beacon Fiber Approaches - $100,000 increase
- Sunset to Downtown West OPGW - $215,000 increase
- Huetter to Prairie Fiber Replacement - $45,000 increase
- Irvin to Boulder Park OPGW - $15,000 increase

The team discussed alternatives consisting of:

- Not partnering with Transmission to install OPGW on the segments mentioned above. By not doing this work, we would need to address the same segments in the future resulting in a different solution and possibly re-work to gain the same outcome as the OPGW work.
- Since the other projects in the business case are already in Execution, the only project that could be pushed to 2024 is the 3rd and Hatch to the Scott Morris Center fiber build but even with this action, additional funding would still need to be requested. This action is a risk since this project is a dependency for the new Metro Substation.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

[1] Wikipedia contributors. (2023). Optical ground wire. *Wikipedia*. https://en.wikipedia.org/wiki/Optical_ground_wire

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Sep-13-2023 | 9:26 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Sep-13-2023 | 4:08 PM PDT
	Steering Committee (If applicable)		

Fiber Network Lease Service Replacement

1.0 CHANGE REQUEST #02 – 2023.11.15

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
11/15/2023	*Scope Change*	02	$1,000,000	($225,000)		
9/20/2023	*Scope Change*	01	$1,000,000	$1,000,000	$1,000,000	$2,000,000
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
11/15/2023	Scope Change	$0	$0	$1,700,000	$2,950,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Fiber Network Lease Service Replacement

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Fiber Network Leased Service Replacement Program Business Case is focused on transitioning Avista's control and safety network from leased lines onto privately owned fiber optic cable. For this business case, the project work identified 47 segments and a total of approximately 98 miles of leased fiber left to be replaced with Avista-owned private fiber. Sometimes those segments are replaced with Optical Ground Wire (OPGW). An optical ground wire (also known as an OPGW or, in the IEEE standard, an optical fiber composite overhead ground wire) is a type of cable that is used in overhead power lines. Such cable combines the functions of grounding and communications.[1]

One project inflight in this business case, 3rd and Hatch to the Morris Center Vault, has run into constraints with internal engineering support being available in addition to delays in onboarding a new construction vendor, resulting in the construction work moving into 2024 versus taking place this Fall. This change in project schedule is resulting in a release of $225,000 from the 2023 budget.

[1] Wikipedia contributors. (2023). Optical ground wire. *Wikipedia*. https://en.wikipedia.org/wiki/Optical_ground_wire

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Nov-10-2023 | 9:41 AM PST
Alexis Alexander	BC Sponsor	DocuSigned by: Alexis Alexander EA27BABA767F467...	Nov-10-2023 | 3:36 PM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Financial and Accounting Technology

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

There were 3 reasons for the TTP variance of $811,985 in 2023:

1. $600,000 was related to the **Power Plan Upgrade** and the addition of the **'Power Tax'** solution upgrade at the same time. As the initial planning for the PowerPlan Fixed Assets upgrade began, it became apparent that we needed to include the 'Power Tax' solution upgrade at the same time. Failure to include the 'Power Tax' upgrade would result in rework associated with both of the 'Power Tax' and 'Fixed Asset' solutions. The estimate from the vendor was a 30% - 40% increase in cost if done separately. This project was originally forecasted at $900,000 and with the addition of the Power Tax module and complex application upgrade, came in at $1,540,000.
2. $100,000 was related to the **Account Reconciliation and Close Automation** project, which was originally planned to TTP in 2022 and TTP'd in 2023. The cost of this project increased due to additional hours required for the System Integrations Testing (SIT) and User Acceptance Testing (UAT) phases, and to allow sufficient time for unexpected data cleansing work (identifying and correcting or removing inaccurate, incomplete, irrelevant, and duplicate data), the project timeline was extended by six weeks. Funds were released to the CPG in 2022 understanding that this would shift a portion of those costs into 2023.
3. $110,000 was related to the **Remittance Processing** project, which was originally planned to TTP in 2022 and TTP'd in 2023. Extreme vendor resource delays caused the project to start later than estimated. Funds were released to the CPG in 2022 understanding that this would shift a portion of those costs into 2023.

The total cost of the Account Reconciliation and Close Automation and Remittance Processing projects were not reflected as 2023 TTP impact, as there were shifts in the project prioritization and roadmap since the original submission. Business Case Governance opted to shift a few of the project schedules due to business need and budget considerations.

Note: Transfer to Plant for 2022 was *under* the original forecast by 600k due to the delays in the Account Reconciliation and Close Automation, and Remittance Processing projects.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

1. Power Plan Upgrade with TFA (Tax Fixed Assets and formerly PowerTax) - PowerTax would be end of life in 2026 at which time we would be forced to move to TFA. Finance & Accounting leadership analyzed the difference between waiting and the move to TFA this year and made the decision for the following reasons:
   - The increase functionality of TFA in the short-term and the long-term expense savings (we get an early adoption discount).
   - There will be additional expense savings starting in 2027 by choosing to move to TFA now instead of upgrading to the last version of PowerTax.
   - There is limited workflow functionality in PowerTax causing lengthy workarounds outside of the PowerTax application.
   - There is a foundational flaw in the way PowerTax was built and the only way to remedy this flaw was to continue to enhance, patch, and submit special requests at additional cost. There are also instance in which we've had to hire a third party to complete work due to lack of functionality.
2. Account Reconciliation and Close Automation - The investment in the Account Reconciliation and Close Automation project provides significant productivity and efficiency gains and was necessary to avoid errors due to manual processes and outdated technology. The Finance and Accounting team was utilizing a labor-intensive process to reconcile and close 900+ accounts on a monthly basis. The time spent reconciling and closing accounts, as well as the risk of errors, was reduced significantly by implementing this automated solution. This system creates indirect labor savings due to better precision of our reconciliation and month end close processes through the reduction in labor requirements, as well as potential re-work from errors.
3. Remittance Processing Upgrade - The Remittance Processing system processes roughly 30% of the incoming revenue for Avista and the risk of not upgrading the software or stabilizing the failing server would result in an inability to process automated customer payments. Unfortunately, this project had schedule challenges from the beginning due to continued unavailability and lack of direction related to preliminary requirements from the vendor.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

Yes, the Power Tax Upgrade project was planned to Transfer to Plant in 2024. Since that work was pulled into the PowerPlan Upgrade in 2023, those offsets/savings are now realized earlier.
This project was to create indirect labor savings due to better precision of Avista's tax depreciation and deferred taxes processes through the reduction in labor requirements, as well as potential re-work from errors. This enables resources to work on higher value tasks and yield indirect savings estimated to be approximately $144,000 in 2023 and likely continue to increase savings in outer years.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Graham Smith
9EDC5D1773BD4CE...

DIRECTOR SIGNATURE:

X DocuSigned by: Hossein Nkdel
E4E2D9C7EE4747F...

Financial & Accounting Technology

1.0 CHANGE REQUEST #1 02/09/23

Previous Requests	Requested	Approved
5-Year Plan	$3,665,000	$2,069,345
CR#1	$500,000	

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
02/2023	$45,825	$2,069,345	$500,000	$2,569,345

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	02/15/23

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

Remittance Processing Refresh - Due to vendor resource delays and the project starting later than estimated, we released funds to the CPG in 2022 understanding that this would shift those costs into 2023. The amount needed to complete this project in 2023 is approximately $500k. This caused a $500,000 impact to the Transfer to Plant (TTP) in 2022 and has now increased the 2023 forecast by that amount.

Also, for visibility and planning purposes, we have recently learned that we need to upgrade the PowerPlan 'Power Tax' solution this year. This upgrade was originally planned to occur with the Power Plan Fixed Assets upgrade but was then pushed into 2024 when this year's budget was reduced, as we did not have the funds to do them both. As the initial planning for the PowerPlan 'Fixed Assets' upgrade began, it became apparent that we needed to include the 'Power Tax' solution upgrade at the same time. Failure to include the 'Power Tax' upgrade would result in rework associated with both of the 'Power Tax' and 'Fixed Asset' solutions. The estimate from the vendor is a 30% - 40% increase in cost if done separately. The cost for the 'Power Tax' upgrade is estimated at ~$400,000. Once costs are further refined, a request for funding will likely be submitted to fund this upgrade.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

As this project is currently in Execution, all incurred costs would be at risk of reverting to expense. If deferred, there would typically be additional time and labor to reacclimate and restart. Also, if deferred, the Finance and Accounting team will continue to utilize more labor related to manual processes, and Customer Service Representatives (CSR's) would have to continue to field these issues in the call center. Finally, this would prolong the customer benefits that are expected from an automated, reliable system that processes a substantial portion of our customer payments, which is critical to remain viable and continue to provide service to customers.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

NA

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented, including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

These project delays increase pressure on the business case budget in 2023, which could potentially cause a domino effect into 2024, etc. The overall project cost has not decreased.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

NA

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The priority and need for this work has not changed. The timeframe in which it will take to deliver the business outcomes have been modified.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid given the nature of this change.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Graham Smith	BC Owner	DocuSigned by: Graham Smith B5895C5C47704C3...	
Ryan Krasselt	BC Sponsor	DocuSigned by: Ryan Krasselt 02B36C66587D411...	
	FP&A		

Finance & Accounting Technology

1.0 CHANGE REQUEST #02

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
02/2023	*Timing Change, Externally Driven*	01	$2,069,345	$500,000	$500,000	$2,569,345
06/2023	*Scope Change*	02	$2,569,345	$470,000		
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
06/2023	Scope Change	*$152,834	$296,834	$2,800,000	$3,449,364

*When these offsets were calculated, the Tax Fixed Assets (TFA) Upgrade was planned to Transfer to Plant in 2024. Since the TFA Upgrade has been pulled into this year (2023) with the PowerPlan Upgrade, the offsets/savings are expected to now impact 2023.

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

PowerPlan Upgrade & Tax Fixed Assets - $400,000

- The ‘Power Tax’ upgrade was originally planned to occur with the PowerPlan Fixed Assets upgrade but was pushed into 2024 due to the reduced 2023 allocation, as we did not have the funds to do them both. As the initial planning for the PowerPlan Fixed Assets upgrade began, it became apparent that we needed to include the ‘Power Tax’ solution upgrade at the same time. Failure to include the ‘Power Tax’ upgrade would result in rework associated with both of the ‘Power Tax’ and ‘Fixed Asset’ solutions. The estimate from the vendor was a 30% - 40% increase in cost if done separately. The cost for the ‘Power Tax’ upgrade is estimated at $400,000.

  This work is predicted to create indirect labor savings due to better precision of Avista’s tax depreciation and deferred taxes processes through the reduction in labor requirements, as well as potential re-work from errors. This will enable resources to work on higher value tasks and yield indirect savings estimated to be approximately $144,000 in 2023 and likely continue to increase savings in outer years.

Account Reconciliation and Close Automation - $70,000

- Due to additional hours required for the System Integrations Testing (SIT) and User Acceptance Testing (UAT) phases, and to allow sufficient time for unexpected data cleansing work (identifying and correcting or removing inaccurate, incomplete, irrelevant, and duplicate data), the project timeline was extended by six weeks. The labor required to complete these items will require an additional $55,000 in funding for Avista labor and $15,000 for our implementation partner, RSM.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date	
Graham Smith	BC Owner	DocuSigned by: Graham Smith 9EDC5D1773BD4CE...	Jun-15-2023	12:38 PM PDT
Ryan Krasselt	BC Sponsor	DocuSigned by: Ryan Krasselt 02B36C66587D411...	Jun-15-2023	8:19 AM PDT
	Steering Committee (If applicable)			

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Fleet Capital Replacement Program

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

To keep our fleet operating reliably and effectively, Avista utilizes a replacement model capital plan using data driven decisions making tools. The Vehicle Replacement Model (VRM) allows us to track the diminishing annual ownership costs with rising annual maintenance cost. This information indicates when the optimal time of replacement should occur based on maintaining the lowest total cost of ownership.

In 2022 we fell short of our forecasted TTP due to supply chain constraint that delayed deliveries we planned for in the last two quarters of 2022. While we took some deliveries in 2022, there are multiple steps after receipt to prepare units for service. The units were placed into service in 2023, leading to higher than originally budgeted TTP in 2023. These include quality inspection, warranty work for identified deficiencies, badging, telematic installation, radio, and technology installations.

When we make our initial forecasts of anticipated TTP they are based on expected delivery times from the manufacturer and vendors. Our units are typically on order two years in advance due to the customized nature of the builds. We attempt to forecast based on the information we have, however we do not have a firm delivery date until the calendar year we will receive them. This has become more difficult to predict over the past four years due to the lack of consistency in the supply chain.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The Capital Planning Group (CPG) allocated our annual capital spend based on our requested 5-year capital business case request. Our Fleet specialist along with inputs from other interested parties develops a strategy to replace the most relevant pieces of equipment based on multiple factors, to make the most prudent use of our capital allocation. These variances in TTP are simply due to the timing of deliveries. As a result of the volatility in the market, we are implementing a contingency plan to make full use of our allocated budget. This involves planning items for early Q1 which if needed, can easily flex to late Q4 to replace delayed or canceled orders.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revisions to offsets for 2023.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: DIRECTOR SIGNATURE:

X Gregory Loew X Kelly Magalsky

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

ER 3009 - Above Grade Pipe Remediation

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Within the natural gas distribution system of all three states (WA, ID, & OR), there are sections of gas pipelines that are located above grade at crossings such as bridges, small ditches, irrigation canals, etc. This Business Case provides capital expenditure for remediating those sites where regular O&M maintenance activities are no longer adequate. Each identified location will be unique in how it is remediated, and the costs will vary depending on the complexity of the project. These projects will typically involve either installing new pipe below grade or rebuilding the existing crossing.

The Above Grade Pipe Remediation program had a lower than planned transfer to plant amount in 2023 due to insufficient staffing at the beginning of 2023. Unplanned retirements at the end of 2022 delayed project planning, design, and permitting through the first two quarters on Above Grade Pipe Remediation projects. Once additional staffing resources were hired and trained, the remaining construction window did not allow for use of the entire planned budget.

The planned transfer to plant was $714,000. The actual transfer to plant was $180,173.

This business case was monitored through the year. In August and October, the Avista Capital Planning Group approved fund releases related to the above-mentioned changes.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Capital spending levels are reviewed monthly. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, gas leadership agrees on submitting funds requests or releases, if necessary. Those funds forms are submitted to the company's Capital Planning Group (CPG) for funding consideration. Approved Business Case Funds Request(s) are included with this form.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets for this period.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Jeffrey A Webb

DIRECTOR SIGNATURE:

X Alicia Gibbs

Gas Facility Replacement Program (GFRP) Aldyl-A Pipe Replacement

EXECUTIVE SUMMARY

In February 2012, Avista's Asset Management Group released findings in the "Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System" report. The report documents specific Aldyl-A pipe in Avista's natural gas pipe system, describes the analysis of the types of failures observed, and the evaluation of its expected long-term integrity. The report proposed the undertaking of a twenty-year program to systematically replace select portions of Aldyl-A medium density pipe within its natural gas distribution system in the States of Washington, Oregon, and Idaho.

The Gas Facility Replacement Program (GFRP) was initiated in 2012 and is planned to continue for 20 years in Washington (until the end of 2031) and in Idaho and Oregon (until the end of 2037). It is the sole mission and charter for the GFRP to plan and execute the replacement of 737 miles of Aldyl-A main pipe and to rebuild 17,769 service tee transitions throughout Avista's service territories. The Aldyl-A main pipe replacement work includes Aldyl-A pipe that is 1-1/4" diameter through 4" diameter and with an install date prior to January 1, 1987, or a manufactured date prior to January 1985. As of July 2023 the GFRP has 335 miles of Aldyl-A remaining to be replaced across Avista's service territory and 626 STTR's left to address via construction or map correction.

Avista has a regulatory mandate to complete this program and has a goal of investing in its infrastructure to achieve optimum life-cycle performance. The historical spending trend from 2018 through 2023 has been $21M-$29M annually. The requested budget amounts consider Avista's regulatory mandate to complete this program with full contractor and company crew complement and to adjust for labor, contract, paving and inflation costs. By completing Aldyl-A replacement on schedule, we are aligning with Avista's Distribution Integrity Management Program's (DIMP) evaluation of risk. This also meets Avista's goal of investing in its infrastructure to achieve optimum life-cycle performance. Inflation of approximately 4-6% has been planned for by escalating the annual forecasted budgets.

This targeted Aldyl-A pipe will eventually reach a level of unreliability that is not acceptable due to the tendency for this material to suffer brittle-like cracking leak failures. There is potential harm to the public through damage to life and property and also a high likelihood of increased consequences from failures in Washington State due to slow crack growth statistics. These statistics show that the number of slow crack growth failures in Washington have remained steady, despite nearly half of the Aldyl-A pipe having been replaced since the programs inception. This data is available in "Avista Utilities Aldyl-A Pipe Analysis (slow crack growth leaks in WA, ID, OR)".

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Michael Whitby*	*Initial draft of original business case*	*2011*	
1	*Michael Whitby*	*Budget Change*	*2015*	*$1.8M approved*
2	*Michael Whitby*	*Budget Change*	*2016*	*$3M approved*
3	*Michael Whitby*	*Budget Change*	*2017*	*$2M returned*
4	*Michael Whitby*	*Budget Change*	*2018*	*$1M returned*
5	*Michael Whitby*	*Budget Change*	*2019*	*$1.5M returned*
6	*Karen Cash*	*Budget Change*	*2020*	*$2.53 returned*
7	*Karen Cash*	*Budget Change*	*2021*	
8	*Karen Cash*	*Budget Change*	*2022*	*$1.31 approved*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	*9/13/23*	***Steve Carrozzo***

GENERAL INFORMATION

YEAR	**PLANNED SPEND AMOUNT ($)**	**PLANNED TRANSFER TO PLANT ($)**
2024	**$27,187,251**	**$27,187,251**
2025	**$28,000,000**	**$28,000,000**
2026	**$30,000,000**	**$30,000,000**
2027	**$33,881,901**	**$33,881,901**
2028	**$34,009,686**	**$34,009,686**

Project Life Span	20 years in Washington and Idaho & 25 years in Oregon
Requesting Organization/Department	Natural Gas / Gas Facility Replacement Program
Business Case Owner | Sponsor	Cody Lee / Alicia Gibbs
Sponsor Organization/Department	Energy Delivery / Natural Gas
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

For Avista, aside from third party excavation damage, the highest risks within our natural gas distribution system is Aldyl-A Main Pipe (Manuf. 1964-1984), and the bending stress that occurs on Aldyl-A service pipe where it is connected to steel main pipe.

The GFRP was initiated in 2012 and is planned to continue for 20 years in Washington & Idaho (until the end of 2031) and in Oregon (until the end of 2037). It is the sole mission and charter for the GFRP to plan and execute the replacement of 737 miles of Aldyl-A main pipe and to rebuild 17,769 service tee transitions. The Aldyl-A main pipe replacement work includes Aldyl-A pipe that is 1-1/4" diameter and great and with an install date prior to January 1, 1987, or a manufactured date prior to January 1985. There is 335 miles of pipe remaining across Avista's service territories.

The GFRP's Service Tee Transition Rebuild (STTR) Program was structured to mitigate the risks associated with the "Bending Stress Services" category within a 5-year time frame. The STTR Program started in 2013 and was deemed substantially complete in December 2017. As of July 2023 there are 626 STTR's remaining in Avista's service territory and are continuing to be remediated by local gas districts.

1.2 Discuss the major drivers of the business case.

Avista has a regulatory mandate to complete this program and has a goal of investing in its infrastructure to achieve optimum life-cycle performance.

As of August 2011, the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) mandates gas distribution pipeline operators to implement Integrity Management Plans, or in Avista's case, a Distribution Integrity Management Plan (DIMP) in which pipeline operators are required to identify and mitigate the highest risks within their system. For Avista, aside from third party excavation damage, the highest risks within our natural gas distribution system is Aldyl-A Main Pipe (Manuf. 1964-1984), and the bending stress that occurs on Aldyl-A service pipe where it is connected to steel main pipe.

More specifically, and as related to the risks identified above, in February 2012 Avista's Asset Management Group released findings in the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report. The report documents specific Aldyl-A pipe in Avista's natural gas pipe system, describes the analysis of the types of failures observed, and the evaluation of its expected long-term integrity. The report proposed the undertaking of a 20-year program to systematically replace select portions of Aldyl-A medium density pipe within its natural gas distribution system in the states of Idaho, Oregon, and Washington.

Subsequently, the Gas Facility Replacement Program's (GFRP) was formed as the operational entity committed to structuring and implementing a systematic approach to mitigating the Aldyl-A pipe risks as identified in aforementioned report.

On December 31, 2012 the **Washington Utilities and Transportation Commission** (WUTC) issued its policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two year for replacing pipe that represents an elevated risk of failure. The requirement to file a Pipe Replacement Plan (PRP) commenced on June 1, 2013. In response to this order, Avista's first 2-year PRP for 2014-2015 was submitted and approved in 2013 per Docket PG-131837, Order 01. Avista's second two-year PRP for 2016-2017 was submitted in 2015 and approved in 2016 per WUTC Docket PG-160292, Order 01. Avista has also submittied and received approval PRP's in 2017, 2019, 2021, and 2023. In Avista's filings, the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report serves as the pipe replacement "Master Plan", and two year pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

On March 6, 2017 the **Oregon Public Utilities Commission** ("Commission") issued Order 17-084 (*Docket UM 1722, Investigation into Recovery of Safety Costs by Natural Gas Utilities)*, which in part required each of the natural gas distribution companies serving customers in Oregon to file with the Commission by September 30th each year an annual "Safety Project Plan" (or Plan).1 The purpose of the Plan is to increase transparency into the investments made by each utility that are based predominantly on the need to achieve important safety objectives. More specifically, the Plan is intended to achieve the following objectives:

• Explain capital and expenses needed to mitigate safety issues identified by risk analysis or new federal and state rules;

• Demonstrate the utility's safety commitment and priority to its customers;

• Provide a non-technical explanation of primary safety reports each utility is required to file with the Commission's pipeline safety staff; and

• Identify major regulatory changes that impact the utility's safety investments.

The **Idaho Public Utilities Commission** (IPUC) has not required gas utility companies to submit an action plan, Avista has submitted the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report for review, and communicates annual pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed now to ensure Avista fulfills the regulatory mandate to complete this program and mitigate risk per DIMP modeling. The need to conduct this program has been identified in "Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System" report. Further, and more specifically, due to the tendency for this material to suffer brittle-like cracking leak failures, Aldyl-A will eventually reach a level of unreliability that is not economically responsible to maintain and repair rather than replace. There is a potential harm to the public through damage to life and property and there is a high likelihood of increasing regulatory scrutiny from increasing failures. Not approving or deferring this body of work would further exacerbate the risks as identified above.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The Gas Facilities replacement Program (GFRP) is responsible for Aldyl-A pipe replacement which aligns with Avista's mission to operate and maintain a "Safe and Reliable Infrastructure". Avista has a goal of investing in its infrastructure to achieve optimum life-cycle performance.

The objective of this investment and structured replacement program is to reduce risk and prevent future catastrophic natural gas incidents. We are holding our customers interests at the forefront of all our decisions by choosing to replace these natural gas facilities. The GFRP also aligns with Avista's strategic vision by doing this in a safe, responsible and affordable manner.

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

a. On December 31, 2012, the Washington Utilities and Transportation Commission (WUTC) issued its policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two years for replacing pipe that represents an elevated risk of failure. The requirement to file a Pipe Replacement Plan (PRP) commenced on June 1, 2013.

b. February 23, 2012 – Avista Utilities Asset Management "Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utilities' Natural Gas System"

c. April 11, 2013 - Revised Avista Utilities Asset Management "Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utilities' Natural Gas System"

d. July 2013 – ARMS Reliability Report – Avista Study of Aldyl-A Mainline Pipe and Bending Stress Point Leaks

e. Avista's first 2-year PRP to the WUTC for 2014-2015 was submitted and approved in 2013 per Docket PG-131837, Order 01.

f. Avista's second 2-year PRP to the WUTC for 2016-2017 was submitted in 2015 and approved in 2016 per WUTC Docket PG-160292, Order 01.

g. Order of the Public Utility Commission of Oregon in Docket UM 1722, Investigation into Recovery of Safety Costs by Natural Gas Utilities. March 6, 2017.

h. Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System report serves as the pipe replacement "Master Plan", and two year pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

i. April 2018 – ARMS Reliability Report - Avista Study of Aldyl-A Mainline Pipe Leaks 2018 Update.

j. August 2020 - Avista Utilities Asset Management "Aldyl-A Pipe Analysis (slow crack growth leaks in WA, ID, OR)".

k. September 2022 – Avista Utilities Asset Management "Study of Aldyl-A Pipe Leaks 2022 Update".

l. Avista's sixth 2-year PRP to the WUTC was approved in 2023 per WUTC Docket PG-230390, Order 01.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System" report details the various time horizons modeled for the Aldyl-A Pipe Replacement program. The Aldyl-A Pipe Replacement effort has been proposed and planned as a systematic 20-25 year pipe replacement program. The program is expected to have a nominal impact to existing business resources, functions, and processes since the GFRP has been structured to function as a "stand alone" program consisting of mostly dedicated internal resources. The primary functions established for these internal resources are to plan, design, oversee, manage, and administer the significant body of projectized work as assigned to "external" contract construction resources.

Periodically, on an as-needed basis, the GFRP will call on other business units for support. Since pipe replacement work is a capital expenditure, the impact to O&M cost has been minimal. Occasionally GFRP projects will encounter circumstances that necessitate O&M expenditures. When known, these O&M costs are estimated prior to construction. The GFRP tracks and monitors O&M costs monthly.

Option	Capital Cost	Start	Complete
Replace priority high-risk Aldyl-A pipe in a 20-25 year timeframe	≈ $635M	January 2012	December 2037

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The 2013 Avista Study of Aldyl-A Mainline Pipe Leaks was updated in 2018 based on the current leaks and replacements statistics through the end of 2017. The study incorporated leak reduction and risk avoidance in the analysis.

After updating the model with leaks and replacements from 2013-2018 the expected number or leaks for the remaining period (2018-2088) reduced from 26,792 to 12,335 due to the large amount of at risk pipe already replaced.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

Scenario	Leaks from 2018 through 2088	IRR	Levelized Gr. Mar. Requirement*	Lev ROE*	NPV equity*
Baseline with effects - 2013	26,792	9.21%	$16,417	$0	$0
20 Year Replacement with effects - 2013	255	6.04%	$23,229	$6,513	$93,490
Baseline with effects - 2018	12,335	18.04%	$10,785	$0	$0
20 Year Replacement with effects - 2018	246	3.87%	$36,147	$12,214	$177,848

* In thousands

Safety risks and criticality were also considered as part of the study update. It is understood that each failure event (leak) does not always result in an injury and this is incorporated as a percentage of events that result per Avista standard modeling guidelines. The severities used are shown in table below. The projected number of catastrophic events drop from 258 to 5 events over the next 70 years by replacing the Aldyl-A pipe.

Effect	Severity	% of Failures Where Effect Occurs
Catastrophic event	50 Years	1.82%
Craft injury, WITH Lost Time/Light Duty	1 Year	0.11%
Craft injury, NO Lost Time	3 Months	0.29%

While Avista's structured replacement program has proven to reduce the highest risk in the early years of the program, the continuation of this structured replacement program is both necessary and prudent to mitigating the remaining risks within the system, and to achieving Avista's goal of operating and maintaining a safe and reliable natural gas distribution system.

The 2013 study predicted a total of 26,792 leaks on Aldyl-A mainline pipe from 2018 through 2088 years without any form of a proactive replacement program. Based upon the proactive replacements that have occurred, the number of leaks predicted over the same period has reduced to 12,335 with 246 catastrophic events if the proactive replacement were to not continue. With the current replacement of all Aldyl-A pipe by 2035, the number of predicted leaks from 2018 to program completion reduces slightly, moving from 255 to 246 leaks of which 4 have the potential to be catastrophic events. The offsets to the GFRP, include but not limited to, regulatory fines, pipeline leaks, pipeline failures and outages, negative company reputation, and elevated safety concerns. See below for a list of the relevant pipeline safety regulations pertaining to the GFRP, as well as a breakdown of each risk over time assuming nothing is done to remediate the Aldyl-A pipe.

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Potential Cost of the "Do Nothing" Alternative.

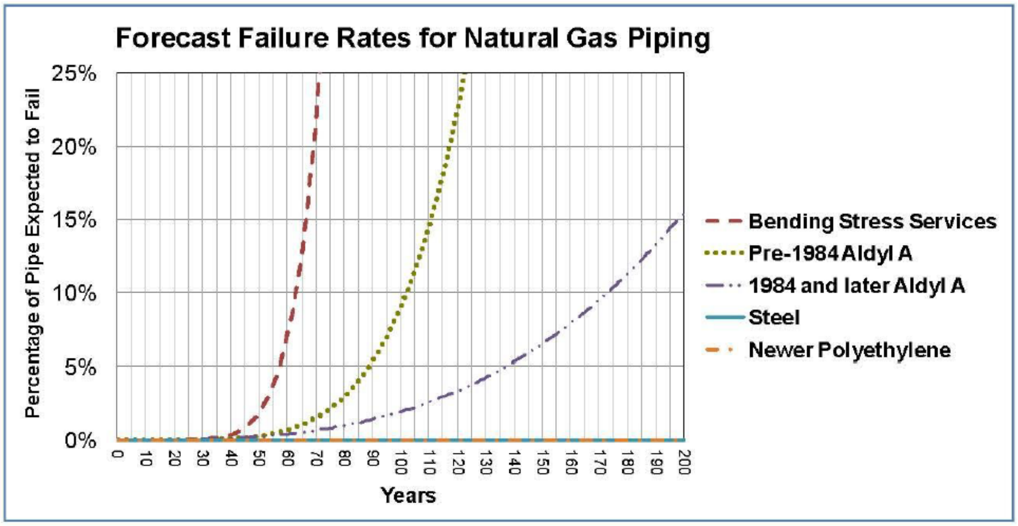
Potential Risk	Potential Risk Over Time					Cost Estimate
	1 Year	2 Years	5 Years	10 Years	15+ Years	
Regulatory Fines	L	P	H	VH	VH	$225,134 per day per violation (Max)* $2,252,334 Total (Max)*
Pipeline Leak	H	H	VH	VH	VH	$5,000 to $150,000 per site (site dependent)
Pipeline Failure & Outage	L	L	P	P	VH	$150,000 to $3,000,000 per site (site dependent)
Negative Reputation	L	P	H	VH	VH	Erosion of WUTC and Public Trust
Employee & Public Safety	VL	L	P	H	VH	Lost time, healthcare, lawsuits, etc. (varies)

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is at the discretion of the enforcement agency and is likely to be much lower due to Avista's ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties.

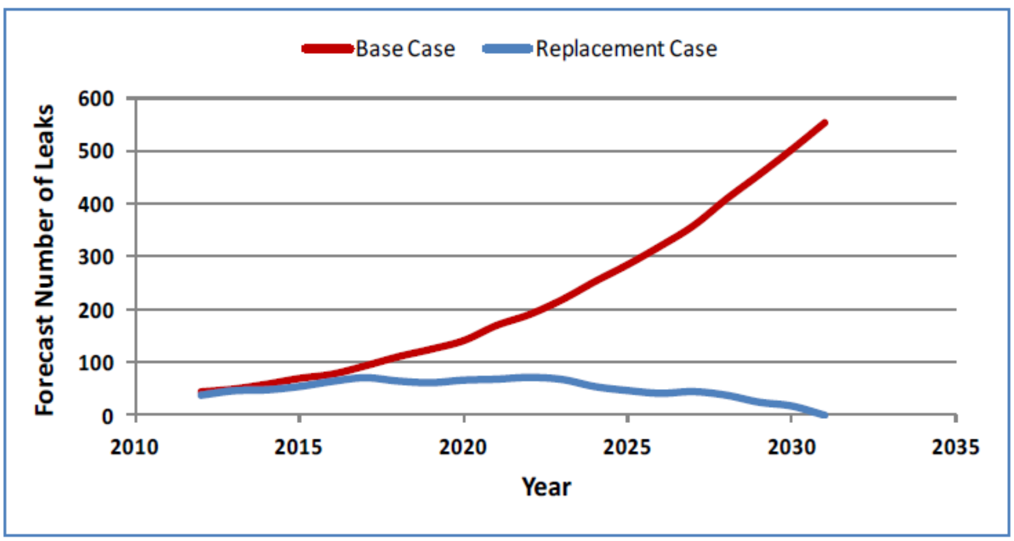
It has been determined that this type of pipe is at risk and is approaching unacceptable levels of reliability without prompt attention. The "Do Nothing" option exposes Avista to increased operational risks, decreased system reliability, and worse, is a potential harm to customers and the public through damage to life, property, and the environment. There would be a high likelihood of legal action against Avista, regulatory fines, and negative reputation. The Aldyl-A pipe will eventually reach a level of unreliability that is not acceptable due to the tendency for this material to suffer brittle-like cracking leak failures. There is a potential harm to the public through damage to life and property and there is a high likelihood of increasing regulatory scrutiny from increasing failures. Not approving or deferring this body of work would further exacerbate the risks as identified above. Additionally, the GFRP would not be able to address some of the highest risk/threats in the natural gas distribution system that have been identified by Avista's Distribution Integrity Management Plan (DIMP).

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

As shown in the graph below and outlined in "Forecasting Results" section of "*Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System*" report, Avista's forecast modeling tool "Availability Workbench Modeling" evaluates several classes of pipe which are represented as "curves" showing the percentage of the amount of pipe class that is projected to fail in each year of the forecasted time period.



The chart below identifies the expected number of material failures in Avista's Priority Aldyl-A piping in two cases: Replacement Case – piping replaced over a 20-year time horizon, and Base Case – assumed that priority piping was not remediated under any program.



Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M	Leak Survey **Cost Avoidance**	$104,630	$112,037	$119,389	$126,789	$134,244

Aldyl-A gas main is leak surveyed on an annual basis rather than the standard five year cycle of other intermediate pressure natural gas mains. The 2023 contracted cost to survey one linear foot of gas main is $0.0458. The 402 miles of Aldyl-A that has already been removed from Avista's system since 2012 and the forecasted 2024-2028 replacement schedules are taken into account for the above O&M direct cost savings. This calculation does not take into account, CPI increases, per diem or Grade 1 standby cost.

Other considerations of direct offsets were also taken into account but not calculated such as reduced system maintenance, leak rates, etc. The GFRP will work with Gas Compliance to establish how we can track and quantify these cost savings in the future.

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Mitigatable Risk Cost Value	$35,150	$69,991	$103,940	$136,545	$167,934
O&M		$	$	$	$	$

The above cost savings represent the probabilistic risk value that is mitigated by removing vintage Aldyl-A gas main from our system. The value is calculated by analyzing the probability of failure times the consequence of failure and also takes into account geographic location, ground composition and history of previous failures. The 402 miles of Aldyl-A that has been removed since 2012 is not calculated since it is no longer in service. The mitigatable risk value is calculated per year and will continue to compound and increase if nothing is done to remediate the Aldyl-A. This model is re-ran annually as risk values increase with the age and degradation of the facility.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Gas Facility Replacement Program (GFRP) Aldyl-A Pipe Replacement

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

To establish context, Avista's goal is to operate a safe, reliable, and cost-effective gas distribution system. Specifically, as related to the above statement, Avista's original 20 year plan is outlined in *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System".* This report details the various time horizons originally modeled for the Aldyl-A Pipe Replacement program. It proposed and suggested that a systematic replacement program conducted over a 20 year timeline was the optimum timeframe to prudently manage risk based on the forecasted number of leaks**,** risks, and the rate impact to our customers.

Since the inception of the GFRP, Avista's Asset Management and Distribution Integrity Management teams have continued to analyze expected trends and potential consequences, making program adjustments as appropriate. The most recent changes made to program timelines are the extension of Oregon and Idaho Aldyl-A pipe replacement to 2037. This is due in part to the reduction of slow crack growth failures in Oregon and Idaho coupled with the number of failures in Washington remaining steady despite nearly half of the Aldyl-A pipe having been replaced since the programs inception. Extending Avista's Aldyl-A replacement work in these states to 2037 will allow us the opportunity to balance affordability and overall impact to our customers. The supporting data and analysis from Avista's Asset Management group shows that risk is continuing to be mitigated and that extending work in Oregon and Idaho will not increase the risk of catastrophic failure.

Alternative 1:

Do Nothing:

It has been determined that this type of pipe is at risk and is approaching unacceptable levels of reliability without prompt attention. The "Do Nothing" option exposes Avista to increased operational risks, and worse, is a potential harm to our customers and the public through damage to life and property, and a high likelihood of legal action against the Company and likely regulatory fines. For this reason it was deemed "not prudent" and is not a serious consideration.

Alternative 2:

Less than 20 Year Pipe Replacement Program:

Avista found that a timeline less than 20 years resulted in a greater cost impact to customers in the near term, and that it did little to reduce the forecast number of leaks expected each year. This approach did not effectively optimize the potential risks and rate impacts.

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

See findings in section 2.2, 2.3, 2.4

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Washington
Start: 2012
Expected End: December 2031

Oregon & Idaho
Start: 2012
Expected End: December 2037

The annual list of projects in each of the three states (ID, OR, and WA) are established as unique "blanket projects" that transfer to plant (TTP) each month as they are "used & useful".

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the Manager of GFRP, Gas Operations Contract Construction Manager, GFRP Business Analyst II, Director of Natural Gas, and the Manager of Gas Design & Measurement. This group meets monthly to review program wide Earned Value results, the status of the delivery of the individual projects, budget allocations and variances, internal resource demands, customer care results and issues, contractor performance, and to communicate potential program risks and shortfalls.

In addition, Avista's Distribution Integrity Management Plan and Asset Management groups provide periodic input, and/or validation of the replacement plan and schedule.

Each year an annual portfolio of projects is derived from Avista's Distribution Integrity Management Program (DIMP) Aldyl-A prioritization list which currently identifies unique priority project areas (polygons) throughout the natural gas system in ID, OR, and WA. The portfolio of projects is sized to meet jurisdictional commitments. Then individual priority projects are planned, phased, scoped, designed, and detailed estimates are prepared. Once the individual project estimates are finalized, the overall program-wide capital budget is refined to reflect a more precise budget. The requested spend level has historically been determined based upon Avista's experience in the management of the Aldyl-A pipe facilities across Avista's service territories coupled with any changing costs of construction year to year.

There are circumstances where lower priority Aldyl-A projects may be accelerated if it makes sense to coordinate the timing of pipe replacement projects with prior phasing or with other utility and road projects. The individual projects for GFRP are typically managed by the Customer Project Coordinators (CPC's) while the overall program budget is managed by the GFRP Manager.

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Facilities Replacement Program Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Cody Lee Date: 10/4/2023
Print Name: Cody Lee
Title: Manager, GFRP
Role: Business Case Owner

Signature: Alicia Gibbs Date: 10/4/2023
Print Name: Alicia Gibbs
Title: Director, Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Avista Utilities Asset Management

Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

May 2013

www.avistautilities.com

Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Executive Summary

Avista Utilities (Avista) protocol for managing select Aldyl A pipe proposes a twenty-year program to systematically remove and replace select portions of the DuPont Aldyl A medium density polyethylene pipe in its natural gas distribution system in the States of Washington, Oregon and Idaho. None of the subject pipe is "high pressure main pipe," but rather, consists of distribution mains at maximum operating pressures of 60 psi and pipe diameters ranging from 1¼ to 4 inches. Further, Avista notes that while there have been concerns with the integrity of steel pipe in other parts of the country in recent years, the steel pipe in its system, including steel service risers, is being managed to protect its long-term reliability and performance and is outside the scope of this program.

In recent years, Avista experienced two incidents on its natural gas system that prompted the Washington Utilities and Transportation Commission and the Company to better understand the potential long-term reliability of Aldyl A pipe. Results of these investigations, which were aided by new tools developed for Avista's Distribution Integrity Management Plan, corroborated reports for similar Aldyl A piping around the country as supporting the development of a protocol for the management of this gas facility. The following report highlights the history of DuPont's Aldyl A natural gas pipe and summarizes DuPont and Federal Agency communications that are relevant to this proposed program. The report documents the Aldyl A pipe in Avista's natural gas system and describes the analysis of the types of failures observed in this pipe, and the evaluation of its expected long-term integrity. Finally, the report describes the results of Avista's work to establish the framework for the proposed protocol for the management of Aldyl A pipe in its natural gas system.

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History of DuPont Aldyl A Piping Systems

Modern polyethylene pipe products are corrosion-free, lightweight, cost-effective, highly-reliable, and can be installed quickly and efficiently. For these reasons, it has for decades been the 'standard for the industry' and is the predominant choice used in natural gas distribution systems. As with any revolutionary product line, polyethylene piping systems have undergone continuous and rigorous testing and product improvement. Such is the case with DuPont's Aldyl A piping systems, as very briefly summarized below.

DuPont Introduces Natural Gas Polyethylene Pipe – 1965

Along with other manufacturers, DuPont began to use polyethylene resin to produce plastic piping for a variety of purposes. The resin was produced from ethylene molecules combined together in repeating patterns to form larger molecules called 'polymers', hence the name 'polyethylene.' DuPont's product designed specifically for use in the natural gas industry was marketed under the name "Aldyl A." The initial resin used in production of Aldyl A pipe, Alathon 5040, was manufactured from 1965 to 1970. DuPont changed the resin in 1970 to improve Aldyl A's resistance to rupture during pressure testing. This improved formulation, known as Alathon 5043, was the primary resin used in DuPont's Aldyl A pipe from 1970 until 1984.

The Phenomenon of "Low Ductile Inner Wall"

Shortly after changing its polyethylene resin in 1970, DuPont detected a manufacturing issue highlighted during laboratory testing of Aldyl A pipe. DuPont learned that its manufacturing process was resulting in some of the pipe having a property described as "low ductile inner wall." "Ductility" is the ability of a material to withstand forces that alter its shape without it losing strength or breaking. A 'highly-ductile' material can be bent, flexed, pressed or stretched without cracking or losing strength because, unlike brittle materials, it can redistribute the forces of stress concentration. Low Ductile Inner Wall, or as it often appears "LDIW," results when the inner surface of the Aldyl A pipe becomes brittle, promoting the formation of cracks and premature failure. In early 1972, DuPont changed its manufacturing process to eliminate this phenomenon, but estimated that 30 – 40% of the pipe it produced in 1970, 1971 and early 1972 was affected, primarily in pipe diameters from 1¼ inches to 4 inches.

DuPont Communicates Potential Issues to Aldyl A Customers

1982 Letter

In 1982, DuPont sent a letter to its natural gas customers, noting that two of its gas utility customers had reported a low frequency of leaks in Aldyl A pipe manufactured prior to 1973. These leaks were reported as "slits" occurring where the pipe was in "point contact with rocks." DuPont noted these two utilities had increased the frequency of leak surveys where rock may have been part of the backfill around the pipe, and encouraged other Aldyl A customers to consider the same. This letter was the genesis of what would become a continuing focus on the pipe vintage known as "pre-1973 Aldyl A."

1986 Letter

DuPont's second letter to its Aldyl A pipe customers was sent in 1986, focusing again on pre-1973 Aldyl A pipe. The letter focused on results of newly-developed (elevated temperature) testing methods that allowed DuPont to more-accurately estimate the longevity of this vintage pipe, in diameters of 1¼ inches and larger. Test results showed that 'Aldyl A pipe manufactured prior to 1973 had certain limitations that were not previously-shown by then-available, state-of-the-art testing methods.' The limitations were described as a reduction in pipe service life caused by: 1) "rock impingement" or pressure from rock points directly on the pipe (as mentioned in their 1982 letter), and 2) the use of squeeze-off practices. The term "squeeze-off" refers to the current and long-standing construction practice of mechanically pressing in polyethylene pipe walls to temporarily stop the flow of gas during work on a line that is in service. DuPont further noted that average ground temperature surrounding the pipe, in the ranges of 60 to 70 degrees (F), had a major bearing on its ultimate expected service life. Finally, DuPont recommended that operators should reinforce the pipe, using clamps that surround the pipe at squeeze points, in order to extend the life of its Pre-1973 Aldyl A.

DuPont Substantially Improves Aldyl A Pipe

DuPont made a significant change to its Aldyl A resin formulation in 1984. The improved resin, known as Alathon 5046-C, was marketed as "Improved Aldyl A", and significantly improved the performance of Aldyl A pipe in its resistance to 'Slow Crack Growth' and overall long-term integrity. Slow Crack Growth, or as it's often abbreviated, SCG, describes the progression of a crack that begins with 'crack initiation' or the formation of a crack in the inner wall of the pipe. The crack then progresses through the pipe wall, usually over period of many years, until it finally breaks through the outer surface of the pipe, resulting in failure.

Again, in 1988, DuPont announced another advance in its Aldyl A pipe resin with the introduction of Alathon 5046-U. This change in resin formulation increased the resistance of the pipe to slow crack growth by another order of magnitude. In addition, because of the high 'molecular efficiency' of this new resin, its density was also reduced, which allowed for much greater ductility in the pipe. This product, the last of the DuPont Aldyl A materials that Avista would install, was also marketed as Improved Aldyl A. A summary of DuPont Aldyl A pipe produced between 1966 and 1992 is presented below in Table 1. Information includes the year of manufacture, resin formulation, relative resistance to slow crack growth (stress rupture testing at 80° C / 120 psig for accelerated life testing), and summary notes.

Table 1. DuPont Aldyl A Pipe 1965 - 1992

Years of Manufacture	Resin	Rupture Resistance*	Notes
1965 - 1970	Alathon 5040		Initial Product Marketed as "Aldyl A"
1970 - 1972	Alathon 5043	10 hours	Resin Improvement and Low Ductile Inner Wall
1970 - 1984	Alathon 5043	100 hours	Resin Improvement
1984 - 1988	Alathon 5046-C	1000 hours	Resin Improvement-- Sold as "Improved Aldyl A"
1988 - 1992	Alathon 5046-U	10,000 hours	Resin Improvement --"Improved Aldyl A"

*Illustrates the order of magnitude difference found from accelerated life testing of resins

Common Classifications of Aldyl A Pipe

Based on the characteristics of the different vintages of Aldyl A pipe, there would emerge over time, (from DuPont's 1982 letter going forward), three age-groupings recognized by the manufacturer, natural gas industry, and regulators as relevant in the reliability management of this pipe.

Pre-1973 Aldyl A – Pipe manufactured through 1972, from the first two resin formulations, and including pipe having low ductile inner wall.

Pre-1984 Aldyl A – Aldyl A pipe manufactured from Alathon 5043 resin, but only that pipe manufactured after 1972 and through 1983.

1984 and Later Aldyl A – Pipe manufactured from the improved Alathon 5046-C and 5046-U resins.

Aldyl A Service Pipe - Small-diameter (less than 1¼ inches) Aldyl A service piping is often treated or managed differently than larger-diameter Aldyl A pipe of the same vintage. This is because the small-diameter pipe has been assessed by industry experts as being more resistant to brittle-like cracking than larger-diameter pipe due to its greater flexibility. Further, small-diameter Aldyl A pipe has been confirmed as being free of the Low Ductile Inner Wall properties present in late 1970 through early 1972 vintage piping.

Federal Bulletins on Brittle-Like Cracking in Plastic Pipe

National Transportation Safety Board

In April 1998, twelve years after DuPont's second letter to customers, the National Transportation Safety Board (Board) published a comprehensive safety bulletin describing their investigation of natural gas pipeline accidents involving polyethylene pipe that had cracked in a "brittle-like" manner. The bulletin focused primarily on accidents related to an early plastic pipe manufactured by Century Utility Products (Century), produced from Union Carbide resin. In its review, findings, and in its Safety Recommendations, however, the Board concluded that in addition to the Century pipe, much of the polyethylene pipe produced for gas service from the 1960s through the early 1980s may be susceptible to brittle cracking and premature failure, further noting that vulnerability of this material to premature failure could represent a serious potential hazard to public safety.

The Board's bulletin represented a seminal work on the vulnerability of early plastic pipe to brittle-like cracking because it analyzed and integrated – for the first time – reports from the technical literature, manufacturers' communications, industry expert opinions, the experience of pipeline operators and regulators' accident reports. Because the bulletin provided a clear understanding of the drivers of failure in older polyethylene pipe, we have included a fairly detailed synopsis in this report.

Objectives of the Board's Investigation

Following the Board's investigation of over a dozen serious incidents, it undertook an effort to evaluate whether the existing pipeline accident data was sufficient for assessing the long-term performance of plastic piping. The office of Research and Special Programs Administration of the National Transportation Safety Board compiled the relevant accident data, but found it to be insufficient for this purpose. Lacking adequate data for the larger assessment, the Board instead focused on estimating the likely frequency of brittle-like cracking, focusing on published technical literature, industry expertise, and work with several gas system operators. From this review, the Board launched a special investigation with the objectives to address three safety issues related to polyethylene gas service pipe:

1. Vulnerability of plastic piping to brittle-like cracking
2. Adequacy of available guidance to pipeline operators regarding installation and protection of plastic pipe tapped to steel mains
3. Performance monitoring as a possible way to detect unacceptable performance in piping systems

Phenomenon of Premature Brittle-Like Cracking

The Board's survey suggested that early plastic piping may be "susceptible to premature brittle-like cracking under conditions of stress intensification." The term 'stress intensification' refers to localized pressure on the pipe wall created by such conditions as rock contact or significant bending of the pipe. The phenomenon of brittle-like cracking was characterized by the failure processes described above, beginning with the initiation of cracks on the inner wall of the pipe at the pressure or stress point, followed by slow crack growth that progressed under normal pipeline operating pressures (much lower than the pressure required to rupture the pipe). The process culminated with the crack reaching the outside wall of the pipe, showing up as a very tight, slit-like opening on the surface, running generally parallel with the length of the pipe. Premature brittle-like cracking was believed, at the time of the Board's safety bulletin, to require relatively high and localized stress on the pipe resulting from sharp or excessive bending, soil settling, rock "impingement" (point or contact pressure on the pipe) , improperly installed fittings, and dents or gouges to the pipe surface. The term 'brittle-like cracking' was used to describe this failure process because the pipe showed no signs of being bulged or deformed where the cracks occurred.

Board Findings on the Three Identified Safety Issues

Issue 1: Vulnerability of Plastic Piping to Brittle Cracking

Long-Term Strength of Early Pipe was Overrated - In the early 1960s the industry had very little long-term experience with plastic pipe, and consequently, developed laboratory testing procedures to forecast the expected service life of piping. Early testing results suggested that polyethylene pipe would exhibit a relatively constant, or 'straight line' gradual decline in strength over time. These tests and underlying assumptions were subsequently incorporated as standards for the industry and in related federal requirements.

As the industry gained experience, however, the straight-line assumptions of these early procedures began to be challenged through the development of new testing methods, where pipe strength was assessed under conditions of elevated temperature (such as the testing referenced in DuPont's 1986 letter to customers). Results of the elevated-temperature testing showed that the decline in strength of early plastic pipe was not gradual or linear as had been assumed, but instead, began to accelerate or drop below the straight line, especially after twelve years. The Board concluded that the early testing procedures may have overrated the strength and resistance to brittle-like cracking of the polyethylene pipe manufactured for the gas industry from the 1960s through the early 1980s.

Long-Term Ductility was Overrated - Another important assumption about early plastic pipe, based on short-term testing, was that it would retain its ductile properties long term. The assumption of long-term ductility had important safety ramifications since it allowed plastic pipe systems to be designed to withstand stresses generated primarily by internal pressure and to give less consideration to the impacts of external stresses such as bending. Unfortunately, the early testing methods did not properly identify the evidence of the "ductile to brittle" transition that was occurring early in the life of the pipe. Consequently, the tests did not distinguish pipe failures resulting from a loss in ductility. The Board noted that this loss of ductility was also observed in the older piping of several manufacturers, those other than Century Utility Products.

Pipeline Operators had Insufficient Notification - The Board noted that premature brittle-like cracking was a complex phenomenon that had not been systematically communicated to the industry, and hence, had not been fully-appreciated by pipeline operators. The Board recognized pipe manufacturers as commonly offering technical and safety assistance to operators, and occasionally, formal reports on their materials. But, because the information on the potential weakness of their products was also mixed with information publicizing its best performance characteristics, the message was not clear. The Board also noted that the Federal Government had not provided relevant information to gas system operators, and concluded that operators had insufficient notification that much of their early polyethylene pipe may have been susceptible to premature brittle-like cracking. Finally, the Board went on to recommend that the polyethylene pipe manufacturers' organization, the Plastics Pipe Institute, advise its members to notify pipeline operators if any of their materials indicate poor resistance to brittle-like failure.

Issue 2: Adequacy of Guidance for Connecting Plastic Pipe to Steel Mains

Critical Understanding of Stress on Pipe - The Board observed that the premature transition of plastic piping from a ductile to a brittle state appeared to have little observable adverse impact on the serviceability of plastic pipe, *except* where the pipe was subjected to external stresses, such as excessive bending, earth settlement, dents or gouges to the pipe surface, and improper installation of fittings, etc. Of those sources of stress, a key factor identified in the Board's bulletin was earth settlement, but particularly in cases where plastic piping was connected to more rigidly anchored fittings, such as steel main pipe. Because the physical properties of plastic and steel respond differently under the same conditions, such as to temperature change and ground settlement, the slight movements of each type of pipe in the ground will be different. This difference in movement can result in significant stress at the point of connection between the plastic and steel piping.

Much of the Guidance to Operators was Insufficient or Ambiguous - In addition to pipeline operators having insufficient guidance on the overall issue of the vulnerability of plastic pipe to brittle cracking, as noted above, the Board also observed that much of the available guidance to operators on how to limit stress on the pipe during installation was inadequate or ambiguous. This was particularly the case with the stress associated with the tapping of plastic service piping to steel mains, where the Board concluded that many of those connections may have been installed without adequate protection from external stress. The Board went on to identify several instances where safety requirements did not fully incorporate safety recommendations, resulting in ambiguity for pipeline installers and regulators. Other highlights of the Board's findings were the many cases where the applicable regulations applying to pipeline installation lacked any performance measurement criteria. Noting that the Office of Pipeline Safety considered many of its safety regulations to be performance-oriented requirements, the Board rebutted this in stating that “many are no more than general statements of required actions that do not establish any criteria against which the adequacy of the actions taken can be evaluated.” A particular example was the regulation that “requires gas service lines to be installed so as to minimize anticipated piping strain and external loading,” and yet it contained no performance measurement criteria for establishing compliance. Finally, the Board went on to note cases where the inadequacy of pipe manufacturers’ instructions also contributed to the lack of a clear understanding of methods to limit stress on plastic pipe during installation.

Issue 3: Monitoring of Plastic Pipe to Determine Unacceptable Performance

The Board’s final objective was focused on performance monitoring of pipeline systems as the key to effectively managing the vulnerable piping types identified in the bulletin. In this discussion, the Board focused on the accident in Waterloo, Iowa in 1994[1], in highlighting the very real challenges of designing effective pipeline monitoring programs. The Board stated that before the accident, the pipeline operator had developed a limited capability to monitor and analyze the condition of its system. It concluded however, that the systems the operator had developed for tracking, identifying, and statistically treating plastic piping failures did not permit an effective analysis of system failures and leak history, noting that their methods of handling of pipe data masked the high failure rates of the subject Century pipe. While the operator did re-evaluate its monitoring data after the accident, and subsequently identified the high failure rates of Century Pipe, the Board opined that the problem could have been detected earlier (before the accident) if the data had been properly analyzed in the first place. Finally, the Board concluded that an effective monitoring program would have allowed the operator to implement a pipe replacement program that might have prevented the accident.

In the second case, the Board noted that while the operator had added capabilities to its pipe-monitoring protocols, it had still not chosen parameters needed to provide adequate analysis of its plastic piping system failures and leak history. The bulletin went on to note examples of the many types of additional parameters needed to enable the effective tracking, identifying, and properly describing system failures and leak history.

The Board concluded that in light of the key findings in its bulletin, that gas system operators may need to be advised once again of the importance of complying with Federal requirements for piping system surveillance and analyses. Regarding the monitoring of older piping, the Board identified the necessity to analyze factors such as piping manufacturer, installation date, pipe diameter, operating pressure, leak history, geographical location, modes of failure, location of failure, etc. Finally, the Board noted that an effective monitoring program would require the evaluation of pipe material and installation practices to provide a basis for the planned and timely replacement of piping that indicates unacceptable performance.

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[1] In October, 1994, a natural gas leak and explosion at Midwest Gas Company in Waterloo, Iowa, resulted in 6 fatalities and 7 injuries. The cause of the incident was identified as the failure of a ½ inch diameter service pipe cracking in a brittle-like manner at a connection to a steel main.

Pipeline and Hazardous Materials Safety Administration

1999 Bulletins

The first two of several advisory bulletins related to the Board's 1998 Safety Bulletin (above), were published by the Office of Pipeline Safety, now known as the Pipeline and Hazardous Materials Safety Administration (Administration), in March 1999. The bulletins, which were issued as advisories to pipeline owners and operators, provided an abstract of the findings of the Board's 1998 investigation and advised that much of the plastic pipe manufactured from the 1960s through the early 1980s may be susceptible to brittle-like cracking. The advisories concluded with the recommendation to owners and operators to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate potential stresses to pipe, and to develop appropriate remedial actions, including pipe replacement, to mitigate any risks to public safety.

2002 Bulletin

This bulletin, as with the prior advisories, reiterated to natural gas pipeline owners and operators the susceptibility of older plastic pipe to premature brittle-like cracking. But, for the first time, this advisory specifically named DuPont's pre-1973 Aldyl A pipe (low ductile inner wall) as being susceptible to brittle cracking. The bulletin also depicted several environmental and installation conditions that could lead to premature, brittle-like cracking failure of the subject pipe, and described recommended practices to aid operators in identifying and managing brittle-like cracking problems.

2007 Bulletin

This bulletin, again, served to review and recap the findings of the prior bulletins, advising natural gas system operators to review the earlier statements. In addition, the advisory recapped results of the ongoing effort of the American Gas Association to identify trends in the performance of older plastic pipe. The advisory reported that the data, at that point, could not assess failure rates of individual plastic pipe materials, but did support what was historically known about the susceptibility of older plastic piping to brittle-like failure, including the addition of specific materials to the list, such as Delrin insert tap tees.

2009 Distribution Integrity Management Program

The Administration published the final rule establishing integrity management requirements for gas distribution pipeline operators in December 2009. Though the effective date of the rule was February 2010, operators were given until August 2011 to write and implement their Distribution Integrity Management Plan (DIMP).

Objectives and Approach

Among other objectives, the program was intended to overcome two key weaknesses in pipeline safety management that were identified in the National Transportation Safety

Board's 1998 bulletin (above): 1) correct weaknesses in federal regulations, particularly in the Office of Pipeline Safety, by establishing true measurement criteria for establishing safety compliance, and 2) establish systematic protocols for pipeline data collection, analysis, and interpretation, that helps ensure accurate integrity assessment and appropriate remediation.

The concept of "Integrity Management" grew out of a demonstration project of the Office of Pipeline Safety designed to test whether allowing operators the flexibility to allocate safety resources through risk management was effective in improving pipeline safety and reliability. Integrity management requires operators, such as natural gas distribution companies, to write and implement Integrity Management Programs (IMPs) to assess, evaluate, repair and validate the integrity of pipeline segments. The program contains the following elements:

- Knowledge
- Identify Threats
- Evaluate and Rank Risks
- Identify and Implement Measures to Address Risks
- Measure Performance, Monitor Results, and Evaluate Effectiveness
- Periodically Evaluate and Improve Program
- Report Results

The Integrity Management approach uses historical leak data and other facility information, along with the input of subject-matter experts, to identify individual threats to a gas system. These threats are then analyzed to predict the likelihood and consequences of failure. Each threat is then ranked by priority, followed by the development of a plan to reduce or remove those risks as deemed necessary.

2011 Call to Action – Transportation Secretary LaHood

Finally, in April 2011, U.S. Transportation Secretary LaHood issued a Call to Action to all pipeline stakeholders in conjunction with the effective application of the Distribution Integrity Management Program. The Call to Action was aimed at the more than 2.5 million miles of liquid and gas pipelines of both federal and state jurisdiction, including transmission and distribution facilities, calling on owners and operators, the pipeline industry, utility regulators and state and federal partners to:

- Evaluate risks on pipeline systems;
- Take appropriate actions to address those risks, and
- Requalify subject pipeline systems as being fit for service.

The centerpiece of the Call to Action is the "Action Plan" of the Department of Transportation and the Pipeline and Hazardous Materials Safety Administration. The focus of the Action Plan is to accelerate the rehabilitation, repair, and replacement of high-risk pipeline infrastructure, calling on pipeline operators and owners to take "aggressive efforts… to review their pipelines and quickly repair and replace sections in poor condition." To buttress this Call to Action, Secretary LaHood has asked Congress to increase maximum civil penalties for pipeline violations, to close regulatory loopholes, strengthen risk-management requirements, add more inspectors, improve data reporting and help identify potential pipeline safety risks early.

Avista's Experience with DuPont Aldyl A Piping Systems

Avista has approximately 12,500 miles of natural gas piping in its service territories in the States of Washington, Oregon and Idaho. Like dozens of other gas utilities, Avista adopted plastic pipe as an excellent alternative to steel, and consequently, the broad majority of Avista's pipe is polyethylene (about 8,500 miles) of various types, ages and brands, including DuPont's Aldyl A.

Avista began installing DuPont Aldyl A in 1968 and discontinued its use in 1990 when DuPont sold their production to Uponor. Of the various vintages and formulations of Aldyl A pipe in its system, Avista has estimated quantities in the following amounts, in diameters of ½" to 4":

Pre-1973 Aldyl A (1965-1972 resins)	190 Miles
1973-1984 resins	960 Miles
1985-1990 resins	919 Miles

Avista noted the advisory bulletins of the Board and Administration in 1998, 1999 and 2002, but since it had no documented trends in the types of failures highlighted, continued to manage its Aldyl A pipe according to established monitoring standards for leak survey and sound operations practices.

Spokane and Odessa Incidents

In recent years, however, Avista experienced two natural gas incidents[2] resulting in injuries and property damage that signaled possible changes in leak patterns in its Aldyl A piping. The first incident occurred in 2005 at a commercial site in Spokane. This event involved the failure of 1976-vintage Aldyl A pipe caused by bending-stress resulting from poor soil compaction around the pipe that was performed by a non-Avista excavator in 1993. The post-incident investigation judged the resulting leak to be an anomaly that could have been prevented with proper care by that 3rd party excavator.

The second incident, at a residence in the town of Odessa, Washington, in late 2008, was determined to be the result of rock pressure on the 1981-vintage Aldyl A pipe that occurred during the initial installation. Avista signed a settlement agreement with staff of

[2] The Pipeline and Hazardous Materials Safety Administration defines a natural gas "incident" as a release of gas that results in any of the following: a fatality or personal injury that requires in-patient hospitalization; property damage of $50,000 or greater, or the loss of greater than 3 million cubic feet of gas.

the Washington Utilities and Transportation Commission as an outcome of the investigation of this incident. Under terms of the agreement, which was subsequently approved by the Commission, Avista increased the frequency of its residential leak survey on pre-1984 resin (pre-1987 installed) Aldyl A natural gas mains in its Washington jurisdiction, from once every five years to annually. In addition, whenever it is excavating in the vicinity of Aldyl A natural gas mains in Washington, Avista will also report on the soil conditions surrounding the pipe, and identify appropriate and reasonable remedial measures, as necessary. Avista retained the consulting services of Dr. Gene Palermo to help develop its approach for managing Aldyl A pipe, in relation to the soil conditions reported.

Expert-Recommended Protocol for Managing Aldyl A Pipe in Relation to Reported Soil Conditions

Dr. Palermo is a nationally-recognized expert on the plastic pipe used in natural gas systems, and in particular, Aldyl A piping. He has worked in the plastic pipe industry for over 35 years, which includes 19 years with the DuPont Corporation in its Aldyl A natural gas pipe division.

Dr. Palermo also served as the Technical Director for the Plastics Pipe Institute from 1996 through 2003 and served on the Institute's Hydrostatic Stress Board for over 20 years. Dr. Palermo has served on a variety of gas industry committees, has trained gas industry practitioners and regulators, and has received numerous awards of merit for his outstanding individual contribution to the natural gas plastic-piping industry. He is the only person to receive both the American Society of Testing and Materials - Award of Merit, and the American Gas Association - Platinum Award of Merit. Dr. Palermo is president of his consulting firm, Palermo Plastics Pipe Consulting.

Dr. Palermo reviewed the content of Avista's agreement with the Commission to become familiar with its requirements, specifically with regard to managing Aldyl A piping found in soils that would currently not meet standard criteria for bedding and backfill. Dr. Palermo's review and expertise provided the basis for his recommended protocol for management of Avista's Aldyl A piping found in rocky soils.

1. All Aldyl A pipe manufactured prior to 1984 should be evaluated for replacement in the following manner:
    a. If the pipe has Low Ductile Inner Wall properties, Avista should immediately begin a prioritized pipe replacement program.
    b. If the pipe is installed in soil with rocks larger than ¾ inch, Avista should immediately begin a prioritized pipe replacement program.
    c. If the pipe is installed in sandy soil or in soil with rocks up to ¾ inch in size, the pipe should remain in service and normal leak surveys per DOT Part 192 should be followed.

2. All Aldyl A pipe manufactured during or after 1984 should also be evaluated.

    a. If the pipe is installed in soil with rocks larger than ¾ inch in size, Avista should evaluate the pipe and consider replacing it if they begin to experience rock impingement failures, and should conduct leak surveys more frequently than required by DOT Part 192, until replacement.
    b. If this pipe is installed in sandy soil or in soil with rocks up to ¾" in size, the pipe should remain in service and normal leak surveys should be followed.

Evaluation of Leak Survey Records

Following the Odessa incident, Avista was also asked to review five years of leak survey records in Washington State to look for possible emerging patterns in the health of its Aldyl A piping system. Avista organized the leak survey information and then conducted several evaluations, which were organized under three general objectives, listed below.

1. Analyze the modes or observed types of failures in Aldyl A pipe;
2. Forecast the expected long-term integrity of Aldyl A piping;
3. Identify potential patterns in the overall health of this piping to aid in the design of a more-focused management protocol for Aldyl A pipe.

Avista used newly-available asset-management tools to conduct these assessments, including its recently-implemented Distribution Integrity Management Program (Integrity Management) approach for identifying and analyzing potential threats to its natural gas system. This approach is suited for just such an analysis, having the capability to determine potential patterns in the overall health of a piping system that might not have been otherwise evident through conventional data review. The analysis of the historic leak survey data, including the observation of several new Aldyl A material failures and leaks, did point to the development of a possible trend.

Pipe Replacement Projects in 2011

Another outcome of this heightened focus on Aldyl A leaks was Avista's decision to replace several thousand feet of its Aldyl A main in 2011. In Odessa, Avista increased the frequency of leak surveys on its gas system to once per quarter and mobilized a pipe replacement program that removed all of the pre-1984 Aldyl A main pipe from the gas system in the town. During that project, which was conducted from June to December 2011, nearly 32,000 feet of Aldyl A main pipe were replaced. Other Aldyl A replacement projects in 2011 removed an additional 7,000 feet of this priority pipe. Together, these projects had a capital cost of approximately $2.7 million.

Avista Distribution Integrity Management Program

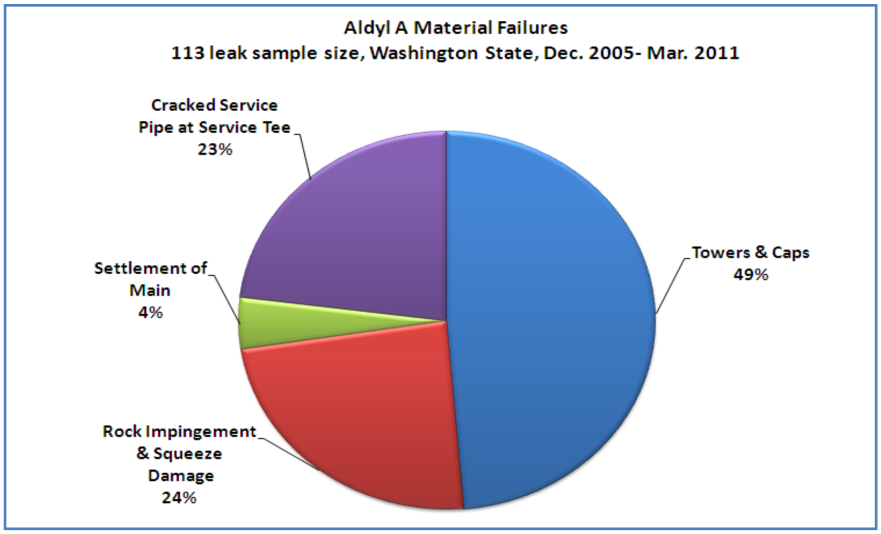
As described briefly above, the Integrity Management approach, now required by law, begins with the aggregation of historical leak-survey data and other facility information relevant to Avista's natural gas piping system. Then, in conjunction with the input of subject matter experts, individual threats to Avista's gas system are identified. These threats are analyzed to predict the likelihood and consequences of failure associated with each threat, based on the specific operating environment, system makeup, and history of Avista's natural gas system. Each threat is then ranked relative to all others to identify, by priority, those with the greatest hazard potential. From that priority list, measures are developed to reduce or remove those risks as deemed necessary. These mitigating measures are often referred to as "accelerated actions" because they may be above and beyond the minimum requirements of applicable federal and state codes. These accelerated actions can range from increased frequency of maintenance and leak surveys to full replacement programs for certain gas facilities. Finally, the mitigating measures will be reviewed to evaluate their effectiveness in reducing threats to the gas system, and the program will then be adjusted as necessary based on those outcomes.

Integrity Management requires the use of geographically-based analytical software to complete many of the required program elements. Like many utilities, Avista is using the Geographic Information System (GIS) platform developed and supported by Environmental Systems Research, Inc. (ESRI), as the geographic and analytical engine for conducting its gas system evaluations under the Integrity Management program. ESRI is a pioneer and world leader in developing and supporting geographic software products for a broad range of global business sectors, including utilities. Since Avista had already created a comprehensive GIS layer, or database, for its gas facilities, it made sense to add analytical capabilities to this platform in complying with the Integrity Management program requirements.

Analyzing Modes of Failure in Avista's Aldyl A Pipe

In tackling the first objective of the assessment of its Aldyl A piping, Avista aggregated the gas leaks resulting from Aldyl A material failures found in its gas system in Washington State from late 2005 through March 2011. The sample included 113 material failures that were evaluated and summarized by component to offer an understanding of the specific failure modes for Aldyl A pipe. The 'modes' or types of material failures categorized are shown below in Figure 1.

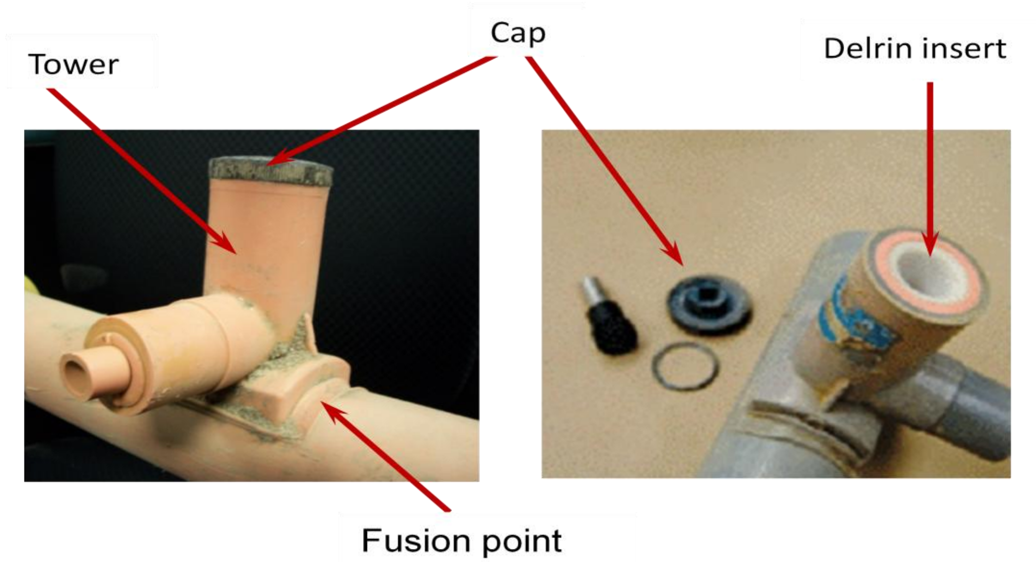
Figure 1. Modes or types of material failures documented in a sample of 113 leaks in Avista's Aldyl A piping in Washington State, December 2005 through March 2011.



Towers and Caps

The largest percentage of material failures in the sample occurred in Towers and Caps, referring to failure of the service tapping tee itself, shown below in Figure 2. In these cases, the pressure applied to the tee as the cap was tightened onto the body during initial installation has resulted in slow crack growth and failure of the tower body, the cap, or the Delrin® insert many years later. Additionally, the saddle fusion point of the tower to the main pipe is another frequent point of failure in this assembly. The unavoidable stresses created during standard installation (using factory recommended procedures) have led to brittle cracking in these components many years later. This phenomenon clearly demonstrates the susceptibility of certain resins of Aldyl A piping to tend to fail by brittle cracking due to the slow crack growth initiated during installation.

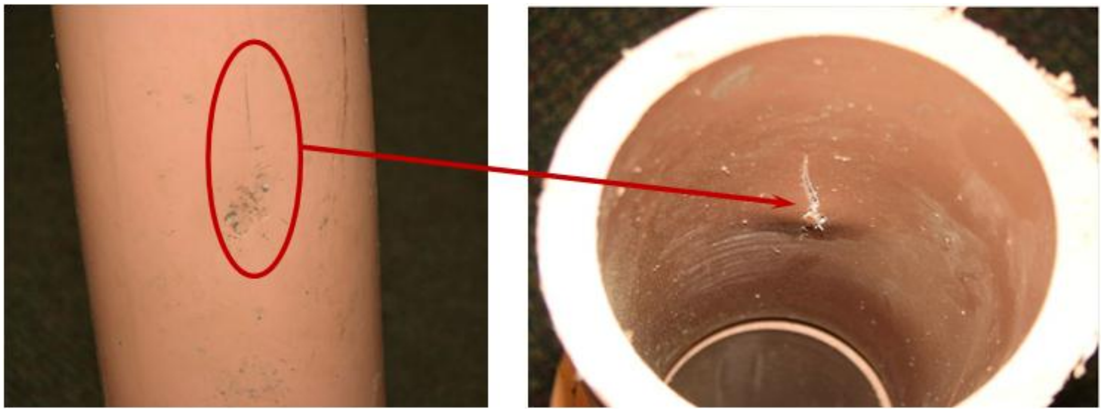
Figure 2. External features and internal components of a typical Aldyl A service tee, as fused to Aldyl A main pipe.



Rock Contact and Squeeze-Off

The second-most common material failure observed in Avista's Aldyl A pipe was due to localized, brittle cracking in Aldyl A mains that resulted from rock impingement – rock pressure directly on the pipe, or places where 'squeeze-off' was applied over the pipe's service life. These failures are very typical for certain resins of Aldyl A main pipe, having been consistently reported by other utilities since before the time of DuPont's 1986 letter. As described earlier, when these external stresses (rock impingement or squeeze-off) cause the pipe to fail, it always begins with crack initiation on the inside surface of the pipe wall, eventually resulting in slow crack growth that propagates toward the outer wall of the pipe, and finally, through-wall failure. These failures generally appear as short, tight cracks in the outer wall of the pipe that run either parallel, or slightly off-parallel with the length of the pipe. A typical failure in Aldyl A main pipe, showing a crack through the pipe wall as it appears on both the inner and outer surfaces, is shown below in Figure 3.

Figure 3. Typical brittle-like crack through the wall of Aldyl A pipe, resulting from rock contact directly on the pipe.



Although the duration of the stress caused by rock contact with the pipe is very different from that associated with squeeze-off, they both result the same pattern of crack initiation and slow crack growth leading to failure of the pipe. Other sources of external stress that can result in brittle failure of Aldyl A pipe, as mentioned earlier in the report, include bending of the pipe, soil settlement, dents or gouges to the pipe, and improper installation of fittings.

Services Tapped from Steel Mains

The third most-common failure in Avista's sample occurred where small diameter Aldyl A service pipe is tapped from steel main pipe. In this application, a steel service tee is welded to the steel main pipe and the small-diameter Aldyl A service pipe is then connected to a mechanical transition fitting on the tee, as pictured below in Figure 4.

Figure 4. Typical polyethylene service tapped from a steel main.

It is at this transition point, between the rigid steel fitting and the more-flexible Aldyl A service pipe, that brittle-like cracking has been observed. This failure mode in older plastic pipe is well understood, and was one of the three study objectives reported by the

National Transportation Safety Board in its 1998 bulletin, summarized earlier in this report.

Avista's Aldyl A Services

Avista believes its Aldyl A service piping (apart from cracking at the connection with the tee on steel main pipe) has no greater tendency to fail than its other polyethylene service piping , and at this point in time, should not be managed differently than other plastic service pipe (frequency of leak survey, etc.). Consequently, Avista is not planning to systematically replace Aldyl A service pipe as it replaces main pipe and rehabilitates service connections at steel tees. Avista is using the Integrity Management model, however, to track and analyze service leaks going forward to determine if the reliability of Aldyl A service piping changes in ways that warrant a different approach.

Understanding the Significance of Leaks in Aldyl A Pipe

Frequency and Potential Consequence

Analysis of the material failures of Aldyl A pipe provides the opportunity to put these leaks into perspective with other types of leaks on Avista's natural gas system. As part of the development of the Integrity Management Plan, five years of leak data were analyzed for Avista's three-state service territory. The data included nearly 17,000 individual leaks, which were categorized according to the underlying threats to the natural gas system as required under Integrity Management. As a point of comparison of the significance of leak types, the data included an excess of 2,000 leaks associated with the failure of gas system equipment, such as valves, fittings and meters. But only 153 leaks were identified as resulting from 'material failures' of Aldyl A piping in the three states. Looking simply at Aldyl A leaks as part of the aggregate of all system leaks, it could be easy to conclude that Aldyl A pipe failures pose a limited potential for hazard relative to the threat of other system leaks. In fact, while gas equipment leaks are more likely to occur, their potential consequence is often minimal. A thorough understanding of this difference is one of the most important requirements and outcomes of any effective Integrity Management Plan analysis.

Review of the leak-history data shows the vast majority of equipment leaks as occurring typically with shut-off valves and gas meters, located either above ground or in locations that allow free-venting of gas to the atmosphere. Consequently, these types of leaks have a low potential to result in an incident posing harm. Through public awareness programs, people have become familiar with the odor of venting gas and tend to quickly call Avista to make repairs; this is especially true if the venting gas can be associated with visible gas valves or meters. By contrast, Aldyl A failures and the associated leaks occur almost entirely underground, out of sight, often in populated areas, and occasionally in the proximity of buildings that are not actually connected to the natural gas system. Without visible facilities, natural gas may have an unexpected presence in the environment that allows people to dismiss slight gas odors. This reduced awareness allows gas from these undetected leaks to have the significant potential to migrate into buildings before it can be identified and reported. This is especially true in winter when the ground is saturated, frozen or snow covered, and in areas of full pavement and concrete finishes. Of the roughly 2,000 equipment leaks reported in the five years of data reviewed, none resulted in gas incidents. By comparison, two of the relatively-small number of Aldyl A material failures resulted in gas migrating into buildings undetected, and upon accidental ignition, resulted in harmful incidents.

The Complication of Brittle Cracking in Aldyl A Pipe

The common mode of failure for Aldyl A materials, brittle-like cracking, can also present special problems compared with leaks in other gas piping, such as corrosion in steel gas pipe. Corrosion leaks tend to begin with the failure of a very minute area in the pipe wall, which then begins to release a very minute amount of natural gas. These leaks then tend to progress very slowly and in a stable and somewhat predicable way over time. These types of leaks, while never positive, are more likely to be detected by modern gas-detection equipment when they are at a stage where the release of gas is relatively minor. By contrast, leaks in Aldyl A piping tend to first appear as substantial (high gas volume) leaks that appear in a very short time period. This is due to the nature of brittle cracking, where the crack can progress very slowly from the inner wall of the pipe toward the outer wall without any release of gas, until the pipe finally splits open, resulting in a substantial failure. Additionally, unlike the prevention or even suspension of corrosion problems in steel pipe through effective protection methods, there is no way to halt undetected progress of slow crack growth in brittle Aldyl A pipe.

Reliability Modeling of Avista's Aldyl A Piping

Avista's Asset Management Group performed reliability modeling for several classes of its natural gas pipe in order to assess the long-term performance of its Aldyl A piping, compared with steel pipe and newer-vintage plastic pipe. Reliability analysis comes from the discipline of 'reliability engineering' and is a foundational asset management tool that provides a forecast or prediction of the future performance of a piece of equipment (pipe, in this instance). The predicted asset performance then provides the basis for the application of other asset management tools, allowing the development of the ultimate maintenance or replacement strategies that optimize asset cost with any number of other factors, such as availability for service or risk avoidance.

Availability Workbench Software

Avista developed reliability forecasts for its Aldyl A and other piping using Availability Workbench™ software. This 'off the shelf software' was introduced by Isograph, Ltd., the world's leader in reliability analysis software. Availability Workbench was first introduced in 1988, and is used to support asset decision making in over 7,000 sites around the world and across a range of industries, including Aerospace, Automotive, Chemical, Defense, Electronics, Manufacturing, Mining, Oil and Gas, Power Generation, Railways, and Utilities. Avista's version of the model was released in 2009.

Reliability Forecasting

Availability Workbench has four modules, one of which, the Weibull module, is used to create reliability forecasts (curves) for an asset. Reliability curves for gas piping are generated from input data that include pipe inventory (type, brand, footage, location, soil conditions, etc.), current age of piping, historic and current failure information and repair data. Avista uses predominantly its own historical data for these inputs, but when they must be estimated, they are vetted by subject matter experts within the company. The model integrates pipe age and failure and repair data, and then by applying a conventional Weibull-curve mathematical model, it produces probability curves that represent the expected failure rates over time for each failure mode, such as the brittle-like cracking associated with Aldyl A services tapped to steel mains. The reliability curves represent how quickly the rest of the pipe is at risk of failing, shown as the percentage of failures expected each year over time.

Forecasting the Reliability of Aldyl A Piping

The objective of Avista's reliability modeling was to forecast expected failures for elements of Avista's Aldyl A piping system, compared with that of steel and latest-generation polyethylene pipe. The observed Aldyl A failure modes, discussed above, including leak data for other types of gas pipe in Avista's system, provided high-quality leak and age information for the reliability modeling. Forecasting was performed for the following pipe 'classes' in Avista's system.

a. Aldyl A Main pipe of Pre-1984 manufacture (Alathon 5040 and 5043 resins, including low ductile inner wall pipe)
b. Aldyl A Main pipe manufactured during 1984 and after (Alathon 5046-C and 5046-U resins)
c. Aldyl A Services Tapped to Steel Main (Bending Stress Services)
d. Steel Main pipe
e. Newer Polyethylene Main pipe (1990 and later)

To perform the modeling, the data for these pipe classes must be input as discrete elements, which are described as follows:

Main Pipe - Analyzed using 50-foot segments as discrete modeling elements.

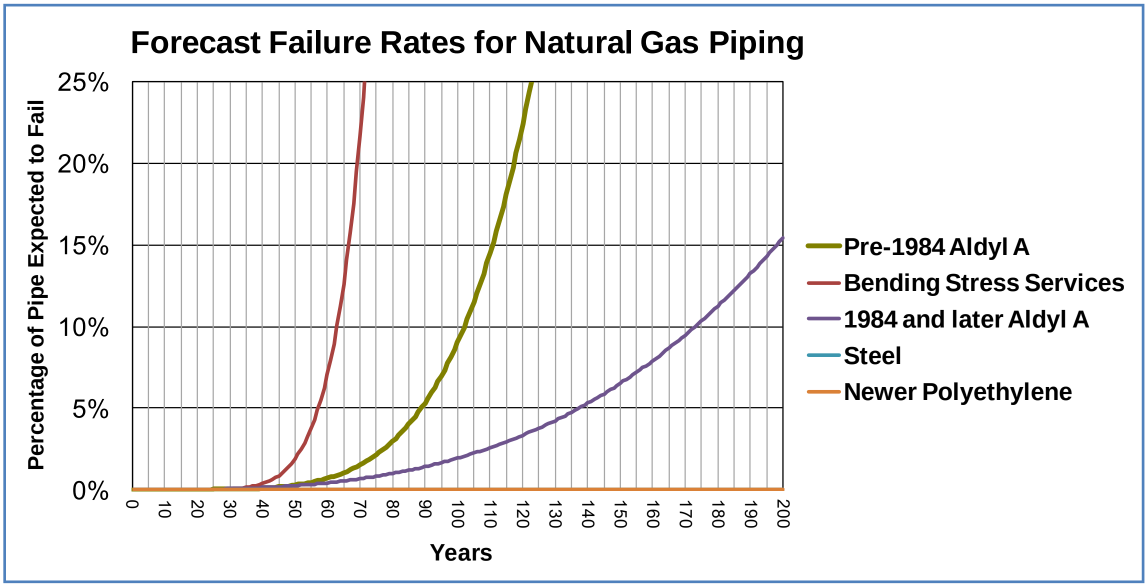
Services Tapped from Steel Mains - Avista identified 16,000 such services in its system, also referred to as 'bending stress tees.' For the reliability modeling, the individual service is the discrete element.

Forecasting Results

Forecast Piping Failures

Results of the forecast modeling, for the pipe classes evaluated, are represented as 'curves' showing the percentage of the amount of each pipe class that is projected to fail in each year of the forecast time period. The resulting reliability curves are shown in the graph below in Figure 5.

Figure 5. The expected failure rates for several classes of pipe in Avista's system, as forecast by Availability Workbench Modeling. The "Steel" curve is obscured by the "Newer Polyethylene" curve, both of which are essentially flat lines.



The failure curves show dramatic differences in the expected life for the pipe classes evaluated. The difference in expected life between the Aldyl A products as a group, compared with that of steel and newer-generation plastic pipe, is particularly evident. Striking also, are the expected performance differences among the classes of Aldyl A pipe evaluated, providing some clear trends useful in designing remediation strategies.

Dependability of Forecasting Future Failures

The reliability forecast is essentially a mathematical calculation of the 'chance' of future failure and decisions of significant risk and financial magnitude are based, at least in part, on that result. Importantly though, the forecast has a 'real numbers' foundation in the actual leak data, records of material failure and repair, and the relationship of those events with time. For Aldyl A pipe, the model is using observed endpoints in the life of the pipe resulting from a loss in ductility and slow crack growth, for example, and integrating that with other data to forecast future expected failures. Comparatively, the relatively rare observed failures in steel pipe and newer-generation plastic pipe are reflected in their nearly-flat cumulative failure curves. The value of using proven reliability forecasting approaches and widely-adopted software is derived from their ubiquitous application across reliability-critical industries, and their continuous testing, evaluation, and support. Finally, as Avista adds new data in coming years for pipe failures of all material classes, including Aldyl A, it serves to increase the statistical power of the forecast results.

Understanding the Significance of Cumulative Failure Curves

Although the failure curves for the different classes of pipe differ significantly over the long term, as mentioned, the failure rates also appear to be very close to zero for the first 40 years for Aldyl A services tapped to steel main, and for 75 years for Pre-1984 Aldyl A main pipe. Since the weighted average age for Aldyl A pipe in Avista's system is 32 years, it would appear that we might have ample time before the failure rate would start to rise substantially for Pre-1984 Aldyl A main pipe. The failure curve estimates that when the Pre-1984 Aldyl A main pipe is 80 years old that approximately three percent of it will fail in that single year. Given that Avista has 335 miles of this vintage pipe in Washington, that mileage equals about 35,000 discrete elements (50-ft sections) in the forecast model. The three percent failure, then, translates to 1,050 leaks in that 80th year. To put that failure rate into perspective, consider that Avista documented just 113 leaks over the past five years in Washington state, two of which resulted in injury and property incidents, and dozens more that were categorized as hazardous leaks[3], timely repaired. Since it is expected that the number of hazardous leaks and incidents would increase proportionally with the increase in total leaks, then it's easy to imagine just how unacceptable the pipe performance would be at an annual failure rate of three percent.

Prudent Failure Management

To carry this point further, if we "zoom-in" on the curves we can gauge the significance of the change in failure rate that is expected ten years from today. At that point the weighted average age of Aldyl A pipe in Avista's system will be 42 years, and the expected failure rate for that year is just over one-tenth of one percent (0.12%), or 42 leaks in that year. The failure rate in that year, then, will have nearly doubled over the average annual rate for the past five years (22.6). The critical point in this analysis is the understanding that failures in buried natural gas piping can be prudently managed only when they are occurring at very low rates. Otherwise new leaks in the system occur too frequently to be detected by even annual leak surveys of the entire system, resulting in an increase in the likelihood of hazardous leaks and the potential for harmful incidents.

[3] The Pipeline and Hazardous Materials Safety Administration defines a "hazardous leak" as an unintentional release of gas that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

Priority Aldyl A Piping

Every pipeline operator strives to install and maintain a safe, reliable and cost-effective system. While the goal is complete system integrity, it is impossible to avoid having any leaks, especially on large systems such as Avista's with over 12,000 miles of mains and several hundred thousand services. Regulators and the industry acknowledge this reality through the adoption of standardized leak-survey methodologies, and recognized pipe remediation practices.

But, while leaks are inherent on a system, there are circumstances where the expected reliability of a particular pipe begins to rise compared with that of other piping and industry norms. We have demonstrated that such is the case for portions of the Aldyl A pipe in Avista's system, and accordingly, we have determined these classes to be at-risk of quickly approaching a level of reliability that is unacceptable and in need of proactive remediation. It's for this reason that Avista refers to these pipe classes as "Priority Aldyl A piping."

Formulation of a Management Program for Priority Aldyl A Pipe

The timely application of Avista's Distribution Integrity Management approach to its recent and ongoing leak analysis and its reliability modeling results, including Dr. Palermo's review, and the experience gained in three priority pipe-replacement projects in 2011, has prompted Avista to formulate a protocol for systematically managing its Aldyl A pipe. The following categories are useful classifications for Avista's definition of "priority Aldyl A pipe"[4]:

1. Aldyl A gas services tapped to steel main pipe
2. Pre-1973 Aldyl A main pipe
3. Pre-1984 Aldyl A main pipe

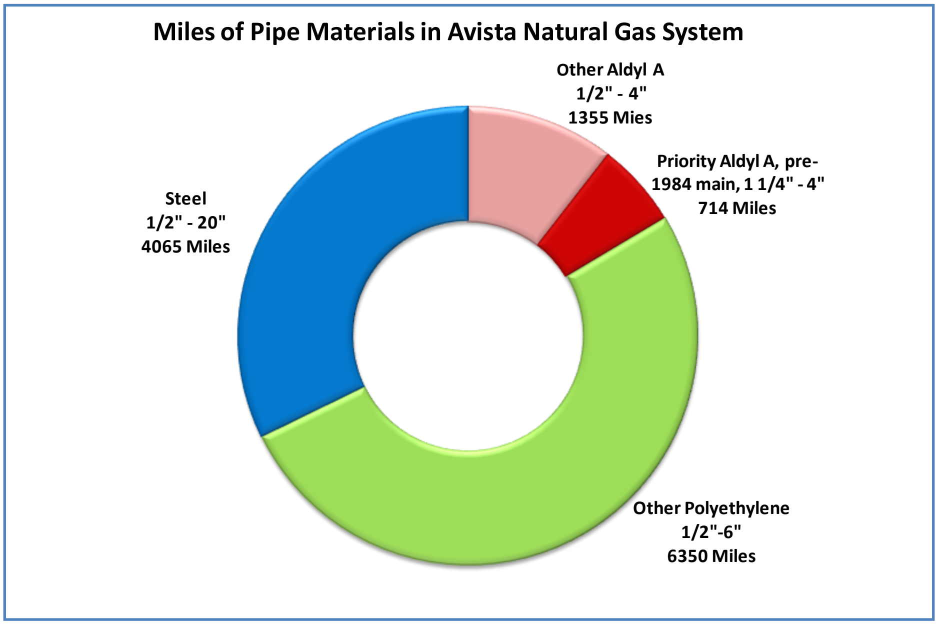
Avista has determined these classes of pipe are at risk of approaching unacceptable levels of reliability without prompt attention. Accordingly, Avista believes the decision to formulate a management program for its priority Aldyl A pipe is both timely and prudent, and is consistent with results of our leak investigations, Integrity Management principles and the recent Call to Action of Secretary LaHood. The decision is also consistent with the prior federal bulletins on this subject and with the decisions of other similarly-situated utilities that have implemented similar pipe-replacement programs. Finally, given the significant amounts of priority Aldyl A pipe on Avista's system, commencing a protocol now provides us greater opportunity to manage this facility in a prudent and cost-effective manner.

[4] Each class noted above is subject to material failures due to concentrated stresses such as rock impingement, bending stresses, squeeze off, and failures of service towers and caps.

Priority Aldyl A Piping in Avista's System

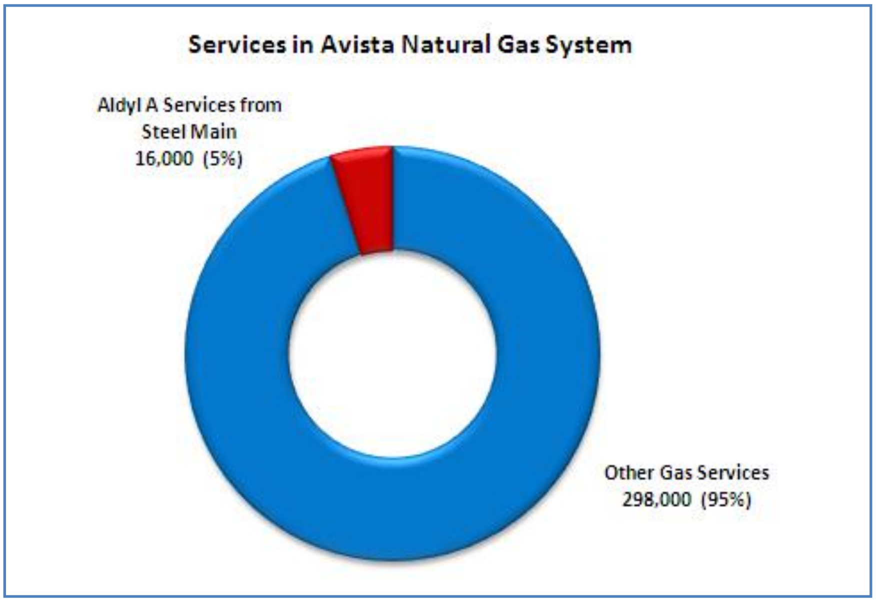
Main Pipe - Avista has approximately 12,500 miles of natural gas main pipe in its service territories in the States of Washington, Oregon and Idaho. Approximately seventeen percent of this total, or 2,000 miles, is Aldyl A pipe of all classes and sizes. Proportions of various classes of piping in Avista's system, including priority Aldyl A pipe (pre-1973 and pre-1984 mains) is shown below in Figure 6.

Figure 6. Avista's priority Aldyl A pipe, shown as a proportion of the different pipe classes in Avista's natural gas system (items 2 and 3 from the list above).



Gas Services - Avista has approximately 314,000 natural gas services, of which approximately 16,000, or five percent, are Aldyl service pipe tapped to steel main pipe, shown below in Figure 7 as priority Aldyl A services.

Figure 7. Avista's priority Aldyl A gas services (tapped from steel mains), shown as a proportion of Avista's total gas services.



Other Aldyl A Pipe Replacement Programs

Aldyl A Pipe in the Pacific Northwest

Through general conversation with our colleagues in western gas utilities, Avista believes it has a substantially greater proportion of Aldyl A pipe in its system than do our neighboring Pacific Northwest gas utilities. The proportions of Aldyl A in Avista's system (or of any other brand of early polyethylene pipe), however, is not a reflection of the unique purchasing practices of Avista, since plastic pipe quickly became the standard of the industry and the predominant pipe installed by utilities across the county. But, the proportions of early plastic pipe in a system do tend to track with the amount of system growth that gas utilities experienced during the 1970s and early 1980s. For Avista, this was a time of particularly rapid expansion of its natural gas system (from the Spokane metro area to outlying communities in its Washington and Idaho service territories), and consequently, the proportion of early Aldyl A pipe in our system reflects this period of expansion.

Established and Emerging Programs for Aldyl A Pipe Replacement

Two western utilities, Southwest Gas and Pacific Gas & Electric, have significant Aldyl A pipe management programs either well underway or anticipated, which are very briefly summarized below.

Southwest Gas – Responding to a fatality incident in the early 1990s, Southwest Gas entered into a settlement agreement with the Corporation Commission of Arizona to conduct additional leak monitoring and pipeline remediation. By the late 1990s, Southwest Gas had replaced 74 miles of Aldyl HD (high density) main pipe covered by the agreement, and had replaced another 648 miles of Aldyl A pipe based on its leak survey monitoring results. In 2005, Southwest Gas had another injury and property incident on their system involving Aldyl A pipe, and implemented an additional pipe replacement program in the vicinity of the incident. Southwest Gas has also worked closely with staff of the Public Utilities Commission of Nevada in the monitoring and replacement of what the Commission refers to as "aging" and "high risk" natural gas pipe, including Aldyl A pipe.

Pacific Gas & Electric - After some very high-profile natural gas incidents in 2011 that involved Aldyl A piping, Pacific Gas & Electric has announced plans to replace all the Pre-1973 Aldyl A pipe in its system. The utility reportedly has 7,907 miles of Aldyl A pipe of all classes in its system, which is about 19 percent of its gas system inventory. By comparison, Avista's Aldyl A pipe stock is about 16 percent of its system. Pacific Gas & Electric's planned replacement of its Pre-1973 Aldyl A pipe represents a massive effort because the utility plans to remove and replace the 1,231 miles of pipe in a proposed timeframe reported as in the range of three years, and at a cost said to exceed $1 billion, but that has not yet been formalized. There is some question regarding the selection of only pre-1973 Aldyl A for replacement in PG&E's system, since at least one recent high-profile incident was reported on newer vintage (still pre-1984) Aldyl A.

Developments of Interest

US Congresswoman Jackie Speier of California has been raising the awareness of Congress and Transportation Secretary, LaHood, in two separate actions. First, in May 2011, Speier sponsored House Resolution 22 entitled the "Pipeline Safety and Community Empowerment Act of 2011." The legislation provided for citizens being able to easily access pipeline maps and safety-related information from pipeline owners, prescribed certain changes in pipeline monitoring requirements, and called for the addition of physical safety devices to existing pipelines. The bill is currently under consideration by the House Committees on Transportation and Infrastructure, and Energy and Commerce.

In October 2011, Speier wrote to Secretary LaHood calling on him to direct the Pipeline and Hazardous Materials Safety Administration to "take immediate action to address the long-known safety risks associated with pre-1973 Aldyl-A plastic pipe manufactured by DuPont." She went on to advocate for the removal of this pipe from use in the U.S., and to commend Pacific Gas & Electric for its planned removal of all of its pre-1973 Aldyl A pipe. Citing the DuPont letters to customers, federal safety bulletins, and the Waterloo incident, she chided Congress for not taking action, and urged the Secretary to immediately do so.

Designing Avista's Replacement Protocol for its Priority Aldyl A Pipe

Avista modeled two different approaches to the replacement program, one that was systematic, based on an established timeframe and one that was responsive to problem areas as they were identified.

Systematic Replacement Program

Time Horizon

Determining the appropriate length of time over which to replace the Priority Aldyl A pipe involves the optimization of several factors, including: 1) the overall urgency from a reliability and safety perspective, both present and forecast; 2) potential consequences; 3) the impact of more intensive leak survey methods to better identify priority facilities in need of replacement and in helping reduce the potential for harmful incidents; 4) the ability to effectively prioritize specific projects to better ensure facilities in greatest need are addressed earliest; 5) the availability of equipment and labor resources needed to conduct the work, and the ability to coordinate the work with Avista's ongoing construction programs; 6) program efficiency, and 7) the degree of rate pressure placed on customers, both in absolute terms and in relation to other reliability and safety investments required across the natural gas and electric business. Ultimately, Avista must ensure that management and removal of its Aldyl A pipe is conducted in a way that shields our customers from imprudent risk, while at the same protecting them from the burden of unnecessary costs.

Prudent Management of Potential Risk

Avista believes it is important to establish for our customers and other stakeholders that while there can never be 'zero risk' associated with the program, the potential risk can be prudently managed. On one hand, a replacement program carried out over a very short timeframe cannot prevent the occurrence of all leaks forecast to occur over the course of the program. But at the other extreme, it's clear that setting a replacement timeline that's too lengthy would likely result in safety, reliability and financial consequences for our customers and our business that could be regarded as imprudent. Avista believes the timeline for the replacement program should optimize the factors mentioned above in a way that reduces the risk associated with Aldyl A pipe to the range of 'prudent risks' associated with the myriad other electric and gas facilities and practices that are used to serve the energy needs of utility customers. Said differently, there is no possible way to eliminate the risks associated with energy infrastructure, but there is a range of limited risk that's deemed prudent in the conduct of our business. Avista's treatment of its Aldyl A pipe will be managed to comport with these sound business practices.

Prioritizing the Work

As important as the replacement timeline in prudently managing the reliability of Avista's Aldyl A piping, is the ability of the Asset Management and Distribution Integrity Management staff to partner in effectively prioritizing the pipe-replacement activities in a way that minimizes the potential for hazardous leaks. Results of the Availability Workbench modeling provide some support in prioritization but do not take into account factors such as soil conditions or the proximity to buildings or people. Obviously, a leak occurring in a vacant field will have little, if any, consequence and will likely be detected and repaired during the next leak survey. By contrast, the potential hazard of a leak increases with its proximity to people and structures, so replacing pipe that has a high probability of leaking and is located in populated areas is first priority.

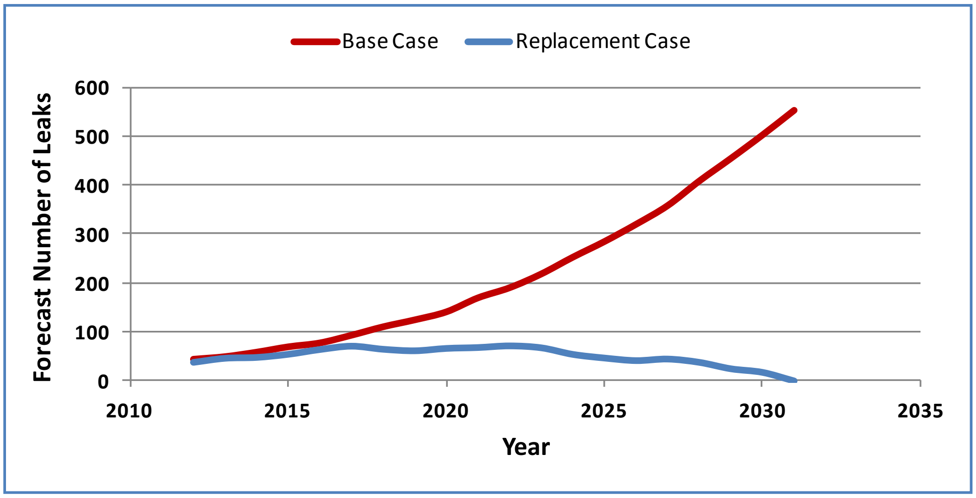
Avista's Integrity Management approach provides the analytical tools that integrate key knowledge and information needed to effectively prioritize replacement activities based on the potential hazard. In the prioritization process, each segment of Aldyl A pipe in Avista's system is assigned a relative risk ranking, based on its age, material, soil conditions, construction methods, and its maintenance and leak history. This information is then loaded into Avista's GIS database containing the gas system maps. These maps contain a "layer" of grid squares (50 feet per side) that correspond with sections of the Aldyl A pipe. Each square is known as a "raster" and each raster contains all of the risk-related information that was loaded into the GIS system, as associated with the Aldyl A pipe, at that precise geographic location.

Next, the software integrates the historic leak information for Aldyl A pipe on Avista's system with the risk data associated with each of the Aldyl A pipe segments, and predicts the geographic areas (via the risk rasters) where Aldyl A pipe failures are expected to be greatest. In the last step, the software integrates the results for expected failures with information for each risk raster that identifies the potential consequence of a leak on that segment (i.e. the proximity of that raster to buildings and people, and the population density/sensitivity of those structures). The end result is a color-coding of the rasters that provides a visual picture of where on the gas system that both the potential likelihood of a leak, and the potential consequence of a leak, are greatest. This approach provides Avista with a comprehensive and objective means of identifying Aldyl A pipe that has the highest priority for replacement.

Twenty-Year Proposal

Avista modeled various time horizons for the replacement program, up to a timeline of 30 years, and determined a replacement horizon in the range of twenty years to represent an optimum timeframe for removing and replacing its priority Aldyl A pipe. Shortening the timeline was found to have increasing cost impacts to customers but with little improvement in the numbers of expected facility failures. Lengthening the timeline past twenty years, however, was found to result in a substantial increase in the number of material failures expected. A replacement timeline of 25 years, for example, resulted in more than a doubling of the number of leaks expected when compared with the twenty year horizon. Under the twenty year replacement program, the number of material failures each year is expected to increase slightly until 2017, at which time the cumulative effect of priority piping replaced since 2012 begins to check the failure count and then drive it toward zero over the remaining course of the program (Figure 8).

Figure 8. Expected numbers of material failures in Avista's priority Aldyl A piping in two cases: Replacement Case - piping replaced over a twenty year horizon in the manner proposed by Avista in this report, and Base Case – assumed that priority piping was not remediated under any program.



Importantly, Avista is not saying that experiencing an increase in leaks on our system is "acceptable" per se, in particular, after having had two harmful incidents in the past few years. What we are saying, however, is that by using the Integrity Management model to prioritize work activities in the manner described above, Avista believes it can manage the forecast Aldyl A leaks in a way that significantly reduces their potential occurrence in areas that could result in harm. Under this approach, Avista believes it can prudently manage the replacement of priority Aldyl A pipe with the goal to avoid harmful incidents altogether, and at a reasonable rate impact for our customers.

Initial Optimization

Importantly, Avista's proposal for a 20-year replacement program represents an optimization based on the information we have available today. Any number of factors could change as the work proceeds over the first few years that could result in a 'new' optimum time horizon. Avista will be collecting new leak survey and other information each year, and will continue to use its Asset Management models to further refine expected trends and potential consequences, making program adjustments as appropriate.

Responsive Replacement Program

Avista also modeled a very-different pipe replacement strategy to provide a further measure of the efficacy of the systematic replacement program. This scenario, referred to as the Responsive Case, was essentially a reactive approach where pipe remediation and replacement activities would be driven by leak survey results and the magnitude of leak consequences. Under this case, it's expected that pipe replacement activity would commence at a lower level than in the systematic case, but would also vary significantly from year to year, depending on patterns of detected leaks and their consequences. Ultimately, however, the expected activity and spending levels would far exceed both the annual and cumulative costs of the systematic approach. This is because pipe segments are not replaced ahead of actual material failure (as happens in the structured case) and so the resulting work activity more-generally follows the geometrically-increasing numbers of material failures expected over time. This scenario was easily judged as failing to provide an appropriate measure of prudence, including system safety, reliability, cost-efficiency, or business risk. Without a prioritized replacement protocol in place Avista would be resigned to replacing pipe in response to serious leaks and potential incidents, after-the-fact, rather than with foresight. Such was the case with the Aldyl A replacements Avista completed in 2011.

From a practical standpoint, Avista believes that by managing the replacement of its priority Aldyl A pipe in a systematic way it can prudently manage potential risks and impacts to its customers and other stakeholders, plan for and use construction resources most efficiently, and plan more effectively for the capital and expense requirements necessary for the effort. This is clearly the case when compared with a responsive approach.

Dr. Palermo's Assessment of the Proposed Protocol for Managing Avista's Priority Aldyl A Piping

Following Avista's Integrity Management evaluations of failure trends in its Aldyl A piping, and the development of its proposed protocol, we invited Dr. Palermo to review the completed protocol and to judge, from his expert perspective, the overall effectiveness and adequacy of the program. Dr. Palermo completed his review in February 2012, and judged Avista's protocol to be highly responsive and appropriate to the management needs of the priority Aldyl A pipe in Avista's system. In particular, he noted his support for Avista's priority focus on pre-1973 Aldyl A pipe, and on the plan to remove and replace its pre-1984 Aldyl A mains. He further noted his agreement with Avista's priority for remediating Aldyl A services tapped to steel main pipe, and to the protocol of "managing in place" existing Aldyl A service piping between the mains and meters. Finally, Dr. Palermo agreed with the proposed twenty-year replacement time horizon for Avista's priority Aldyl A pipe, noting the reliability modeling results, and the effectiveness of Avista's increased leak survey and application of Integrity Management information, tools and analysis in prioritizing pipe replacement activities. Dr. Palermo reviewed and approved this affirmation prior to the finalization of this report.

Application of Avista's Washington State Study Results to Aldyl A Pipe in the States of Oregon and Idaho

Forty-six percent of Avista's Aldyl A main pipe is currently in service in the State of Washington, and coincidentally, so are 46% of Avista's Aldyl A services tapped to steel mains. Since Avista's leak survey study and subsequent modeling results are based on Washington State data, then it follows that the expected results are most applicable to this jurisdiction. The degree to which the reliability modeling results are applicable to Avista's Aldyl A pipe in the States of Oregon and Idaho depend on factors such as the age of the at-risk pipe and on the known similarity of conditions under which the pipe was installed, including method (trenching or plowing), backfill material, compaction and squeeze-off practices, soil conditions and ambient soil temperature, etc. Avista is aware of at least some general differences among state jurisdictions, including more favorable soil conditions in Oregon, newer pipe materials, and construction techniques potentially more favorable to low-ductility pipe. A contributing complication, too, is the relatively large amount of pipe of unknown age and material in services in Oregon. This territory was acquired by Avista from a utility that did not have a consistent practice of mapping services, and some existing maps were lost before the purchase. As a result, Avista is conservatively managing this 'unknown' pipe as if it was priority Aldyl A pipe, until the time that these segments are verified by records review and possible field verification.

Most important to this discussion, however, is the fact that Avista is using its Integrity Management model to integrate leak survey and other data to develop the priority pipe replacement activities for each year of the program. Since comparable leak survey data from priority Aldyl A pipe in Idaho and Oregon will be included in the prioritization analysis, then regardless of any differences that do affect the expected reliability of the Aldyl A pipe, that inherent reliability will be automatically integrated into the modeling, ensuring that Avista is systematically replacing the pipe at greatest risk, regardless of the jurisdiction. Finally, since the Medford and Grants Pass, Oregon, service territory offers a 12-month construction season, Avista will be able to continuously mitigate priority Aldyl A piping within that area when northern territories are effectively unable to continue working.

Resource Requirements and Expected Cost

Staffing

Avista's proposed Aldyl A pipe replacement project represents a major undertaking, even when spread over a twenty-year horizon. In addition to the scope of the effort, there's added complexity in efficiently managing the project, since Avista's territory extends from Bonners Ferry, Idaho to Ashland, Oregon, a distance of over 650 miles. Each year, the deployment of equipment and inspection and construction personnel will have to be adjusted across this service area in response to the sites identified for highest-priority pipe replacement in any given year. Avista is planning to coordinate with contractors to manage much of this construction, and since this project represents a long-term construction commitment, it is expected that the pool of contractors bidding for this work will be substantial, resulting in advantageous pricing and flexibility of field labor.

Though much of the physical construction will be accomplished through the use of contractors, there will still be a need to increase Avista's internal staffing to manage the flow of information, quality assurance, mapping, and related project documentation. Quality assurance is a critical project element that Avista will rigorously control. Effective remediation of Avista's priority Aldyl A pipe is a critically-important corporate objective, and we must continually ensure that sound inspection, training and auditing delivers the results we expect. Finally, the pipe replacement activities themselves will often have disruptive effects on our customers and others. Avista will carefully coordinate customer and community communications and notifications in an effort to minimize the effects of any disruptions.

Capital Costs

Avista's analysis and planning effort is projecting capital costs just over $10 million annually from the year 2013 – 2032. Actual costs will vary somewhat depending on the prioritization of piping to be replaced each year, among other factors, and the calculated amounts will also be subject to an estimated 2.3% annual inflation. Avista is planning to spend approximately $5 million in capital on this program in 2012, allowing for effective planning with contractors, hiring Avista staff, and developing a solid project management foundation for years 2013 and beyond.

Avista Utilities

Study of Aldyl-A Pipe Leaks 2022 Update

Asset Management

9/15/2022

Executive Summary

Avista began a program to replace all its Aldyl-A pipe in 2011 in Washington, Oregon, and Idaho. A regulatory mandate to replace the pipe in 20 years is in place for Washington State (2031 deadline). While not mandated to do so, Avista enabled similar replacement timelines for Idaho and Oregon. The purpose of this report is to provide a regulatory update on progress made. Avista provided similar updates in 2013 and 2018. While not limited to the following, the update's primary intent is to show the amount of pipe removed (to date), the pipe removal costs, and the impact to safety from the remaining Aldyl-A pipe in the ground.

Washington and Idaho, despite rising costs, are on track to have all Aldyl-A pipe replaced by 2031. It is likely the Oregon replacement will not be complete until 2037. Several slowdowns have occurred in Oregon due to COVID-19 impacts, contractor strikes, 3rd party contractor staffing issues, wildfires, and municipal permitting turnaround times. Part of this study/update will target specifically the risk impact of extending the Oregon program out additional years. While all risk cannot be eliminated, the question to be answered is whether the Oregon extension adds substantial risk to Avista's customers living within these service territories.[1]

Scope

The scope is limited to Asset Management providing a review and update on Avista's Aldyl-A pipe replacement program. A key factor in this update is testing whether the remaining ("in use") pipe carries an unacceptable level of catastrophic failure risk that justifies amending the program's existing timeline[2]. Based on risk levels, can the program be extended, in Oregon, to 2037, given the delays noted above? The update will also provide detail on the amount of pipe that has been replaced, the amount of pipe still in active use, and the costs associated with pipe replacement. Benefit/Cost for the program will be discussed and it is noted the primary driver for removing the pipe is the catastrophic risk associated with the Aldyl-A pipe and not whether the program cost justifies itself. Consideration is being given to two failure type modes: service tees and slow crack growth. It is recognized that other failure modes exist, but these two failure modes are unique to the Aldyl-A pipe.[3]

[1] Similar safety criticality test and results will be discussed for WA, ID and OR. However, OR will be looked at separate due to the likely extended timeline (completion by 2037).
[2] Refer to Key Assumptions/Constraints. Availability Work Bench ('AWB') software was utilized to run Safety Criticality tests for the remaining pipe still in use.
[3] Remaining failure modes, considered for the Aldyl-A pipe, would not be all that dissimilar to the replacement pipe being installed.

Regulatory Requirements

As of August 2011, the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) mandates gas distribution pipeline operators to implement Integrity Management Plans, or in Avista's case, a Distribution Integrity Management Plan (DIMP) in which pipeline operators are required to identify and mitigate the highest risks within their system. For Avista, aside from third party excavation damage, the highest risks within our natural gas distribution system is Aldyl-A Main Pipe (Manuf. 1964-1984), and the bending stress that occurs on Aldyl-A service pipe where it is connected to steel main pipe.

More specifically, and as related to the risks identified above, in February 2012 Avista's Asset Management Group released findings in the "*Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System*" report. The report documents specific Aldyl-A pipe in Avista's natural gas pipe system, describes the analysis of the types of failures observed, and the evaluation of its expected long-term integrity. The report proposed the undertaking of a 20-year program to systematically replace select portions of Aldyl-A medium density pipe within its natural gas distribution system in the states of Idaho, Oregon, and Washington.

Subsequently, the Gas Facility Replacement Program's (GFRP) was formed as the operational entity committed to structuring and implementing a systematic approach to mitigating the Aldyl-A pipe risks as identified in aforementioned report.

On December 31, 2012, the **Washington Utilities and Transportation Commission** (WUTC) issued its policy statement on Accelerated Replacement of Pipeline Facilities with Elevated Risks which requires gas utility companies to file a plan every two years for replacing pipe that represents an elevated risk of failure. The requirement to file a Pipe Replacement Plan (PRP) commenced on June 1, 2013. In response to this order, Avista's first 2-year PRP for 2014-2015 was submitted and approved in 2013 per Docket PG-131837, Order 01. Avista's second two-year PRP for 2016-2017 was submitted in 2015 and approved in 2016 per WUTC Docket PG-160292, Order 01. Avista submitted a PRP in June 2017, and 2019. In Avista's filings, the *"Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System"* report serves as the pipe replacement "Master Plan", and two-year pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

On March 6, 2017, the **Public Utility Commission of Oregon** ("OPUC") issued Order 17-084 (*Docket UM 1722, Investigation into Recovery of Safety Costs by Natural Gas Utilities)*, which in part required each of the natural gas distribution companies serving customers in Oregon to file with the OPUC by September 30th each year an annual "Safety Project Plan" (or Plan). The purpose of the Plan is to increase transparency into the investments made by each utility that are based predominantly on the need to achieve important safety objectives. More specifically, the Plan is intended to achieve the following objectives:

- Explain capital and expenses needed to mitigate safety issues identified by risk analysis or new federal and state rules.
- Demonstrate the utility's safety commitment and priority to its customers.
- Provide a non-technical explanation of primary safety reports each utility is required to file with the OPUC's pipeline safety staff; and
- Identify major regulatory changes that impact the utility's safety investments.

The **Idaho Public Utilities Commission** (IPUC) has not required gas utility companies to submit an action plan, Avista has submitted the "Avista's Proposed Protocol for Managing Select Aldyl-A Pipe in Avista Utility's Natural Gas System" report for review and communicates annual pipe replacement goals which includes specific project locations, and the anticipated pipe replacement quantities.

Key Objectives/Assumptions/Constraints

Key Objective:

Utilizing a Safety Criticality test, demonstrate whether an unacceptable risk of catastrophic failure exists on the remaining Aldyl-A pipe. Assuming a test failure, alternative approaches would be considered, including moving up, rather than extending timelines. Through this same test, confirm whether a timeline extension in Oregon is appropriate given the risk parameters set around this program. In addition, provide an update on progress made (to date) and discuss the costs involved with this program.

Key Assumptions/Constraints:

Weibull Curve

- Utilizing data from prior updates, existing leak data, and input from Subject Matter Experts, the Weibull curve parameters were established. Existing pipe data was incomplete for building out the model due to the fact it has yet to complete a full life cycle. Therefore, the existing data set required certain assumptions to be made to build out the model.
    - ETA, 80 years.[4]
    - Beta, 4.[5]
- Unit quantity based on size of Phase replacement. Oregon = 1,025 feet (Phase). Washington/Idaho = 2,000 feet (Phase).[6]

[4] Assumes 63.2% of all pipe sections will have experienced a failure within 80 years of installation.
[5] Beta < 1, Infant Mortality, Beta = 1, Random Failure, Beta > 1, Long Term Failure. In line with 2018 study that used a 3.95 Beta for Rocky Soil and 4.02 for Sand.
[6] A 10,000-foot stretch of pipe would equate to 5 units for WA/ID and 10 units (rounded) for OR.

Failure Mode(s)/Consequences

- Failure modes utilized in this update:
    - Slow crack growth
    - Service Tees.
- Leak data is from 2011 (program start date) to 2021 and was provided by Avista's Manager, Natural Gas Pipeline Integrity.
- Effects (consequence of failure), for modeling purposes, were limited to catastrophic failure. Failures, both catastrophic and non-catastrophic, would require immediate replacement. However, the costs to repair a non-catastrophic failure are immaterial to the overall results, do not impact the Safety Criticality test, and do not provide cost justification for the overall program.
    - Catastrophic Failure cost, $20,000,000.
    - Catastrophic Event occurrence, 1 every 40 years.
        - Redundancy Factor, 0.00125, based on an assumed 20 leaks/year.[7]
- Inspections are successful in detecting leaks but not necessarily preventing future leaks. Therefore, the Potential Failure/Functional Failure (P-F) Interval on leak detection = 0.[8]

Safety Criticality Test

- Safety Criticality Test models the likelihood of a catastrophic failure over a certain time period.
- Test parameter, 1 failure in 40 years.[9]
- Lifetime model simulation, 10 years. Assumes all or most of the remaining pipe will be replaced in the next 10 years; Oregon is likely to be complete in 15 years.
- Test simulation run for each year of the 10-year period. When the next year is modeled, the pipe is aged 8,760 hours (1 year) and the amount of expected pipe to be removed (prior year) is subtracted from the total.
- Oregon replacement assumed to be 15 years. Therefore, residual safety risk exists, for Oregon, after the 10-year run period. Approximately 56 miles of pipe, to be replaced, will remain in Oregon after 10 years.
- Safety Criticality results ≥ 1 = failure.
- Safety Criticality test run separately for Idaho & Washington and Oregon, given the expected different timeline to completion for Oregon.

[7] 28 leaks were detected in 2020 (WA/ID/OR) while 18 were detected in 2021. 20 leak assumption is conservative based on pipe replacement program which reduces mileage annually. Less pipe in the ground assumes fewer leaks.
[8] Assumes a pipe section passes a leak test but could fail as soon as the next day. Inspection does not create safe period for risk avoidance. Test is limited to determining whether an existing leak exists.
[9] For clarification, 1 or greater failures over a 40-year period would indicate a test failure.

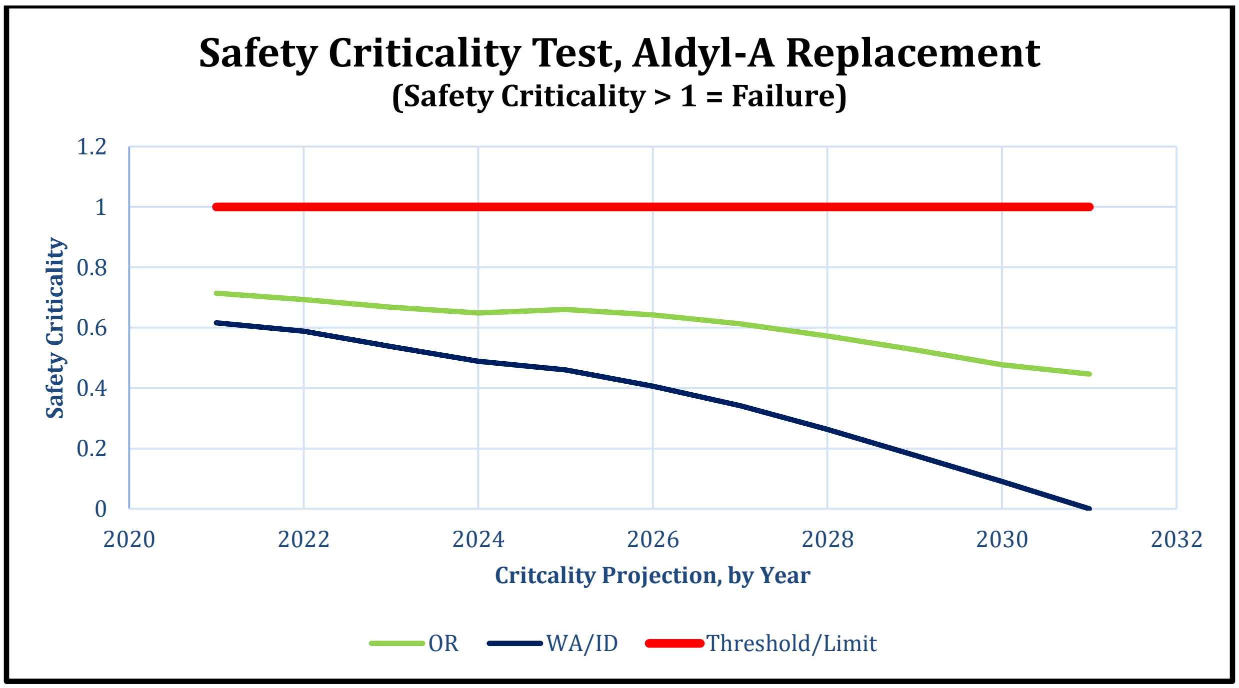
Linear Regression Assumptions

- Linear Regression analysis based on the leak data from 2011-2021.
- All slow crack growth and service tee leaks are included. Additional leaks, not specific to Aldyl-A, are removed from consideration as those leak types would occur with non Aldyl-A pipe.[10]
- Leaks per mile are determined by comparing total leaks to in use pipe remaining (end of year).

Results/Findings

Safety Criticality threshold not exceeded: (Test Passed)

Safety Criticality Test was built in Availability Workbench (refer to Key Assumptions, above). As already noted, the Safety Criticality Test was built around the probability of a catastrophic event occurring in the next 10 years. Based on the replacement schedule, the test is passed in all instances for Idaho/Washington and Oregon. Therefore, a critical failure is highly unlikely throughout the remainder of this program (refer to chart below).



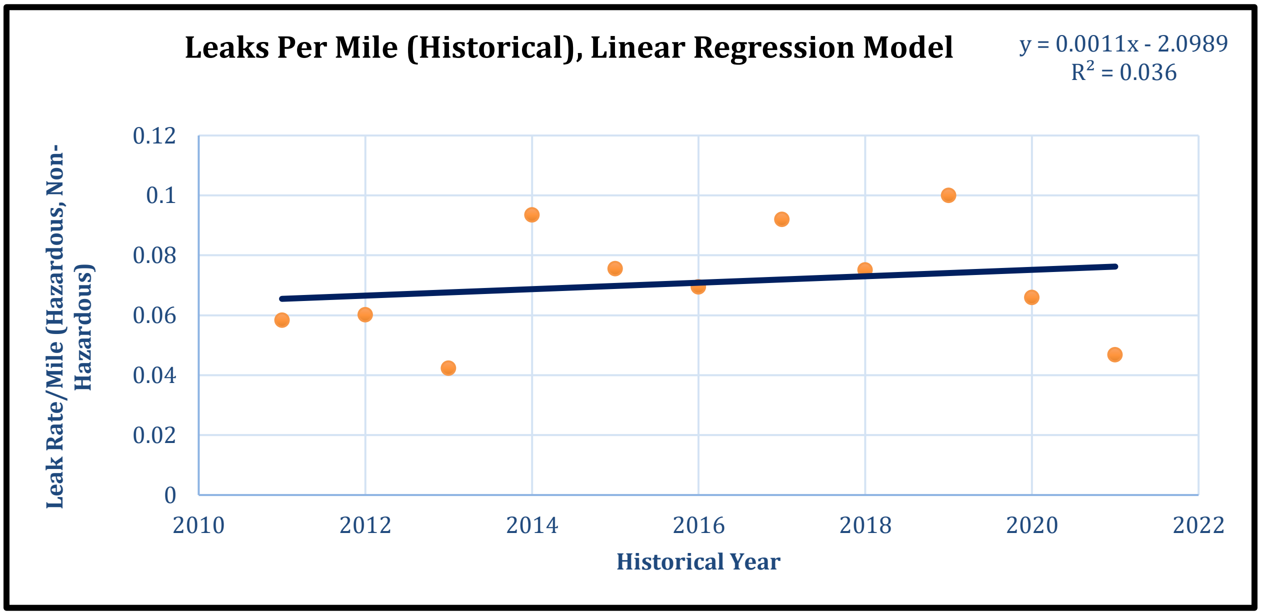
- Safety criticality test success does not eliminate all risk. Rather, the likelihood of a catastrophic failure is unlikely.[11]

[10] Purpose of the study is to isolate those leaks (failures) specific to Aldyl-A.
[11] Safety Criticality Test factors in number of prior leaks, age of pipe and the planned replacement schedule.

- Declining trend supported by pipe replacement. The pipe that is replaced is removed from future test consideration. Example: 300 miles of in use pipe remains. 40 miles is removed in year 1. Year 2 calculation would be based on 260 miles of in use pipe (300-40=260 miles).
- Residual risk remains for OR after 2031 because the OR portion is not expected to be completed until 2037. WA/ID assumes all pipe is removed by 2031.

Linear Regression Analysis shows stable trend and overall risk reduction:

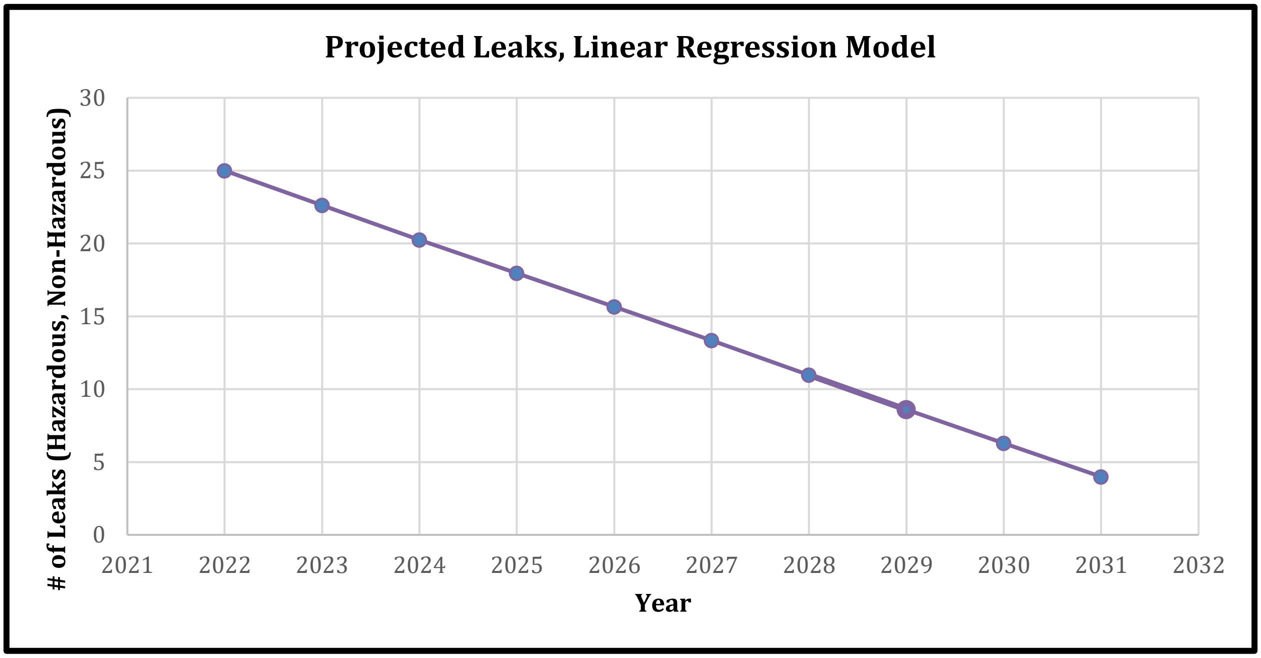
The Linear Regression Model (below) measures the number of hazardous and non-hazardous leaks since 2011.[12] The leak rate per mile can be determined through linear regression. As shown, there has been a slight uptick in the number of leaks per mile but the overall the trend is relatively flat and stable.



- Low R^2 suggests randomness in the data set but is consistent with the age of the pipe (yet to experience long-term wear out, therefore subject primarily to random failures and infant mortality).
- Trend line is relatively flat and while ticking up, it does not suggest a near-term material concern that supports changing the project's timeline.

[12] Linear Regression includes slow crack growth leaks and service tee problems experienced since 2011 for OR, ID and WA (combined). Hazardous and Non-hazardous leaks relate to the immediacy for a response. A hazardous leak does not mean a catastrophic failure has occurred.

Utilizing the linear regression equation (chart, above, top-right), the expected number of leaks can be plotted against anticipated remaining pipeline in the ground at end of year.



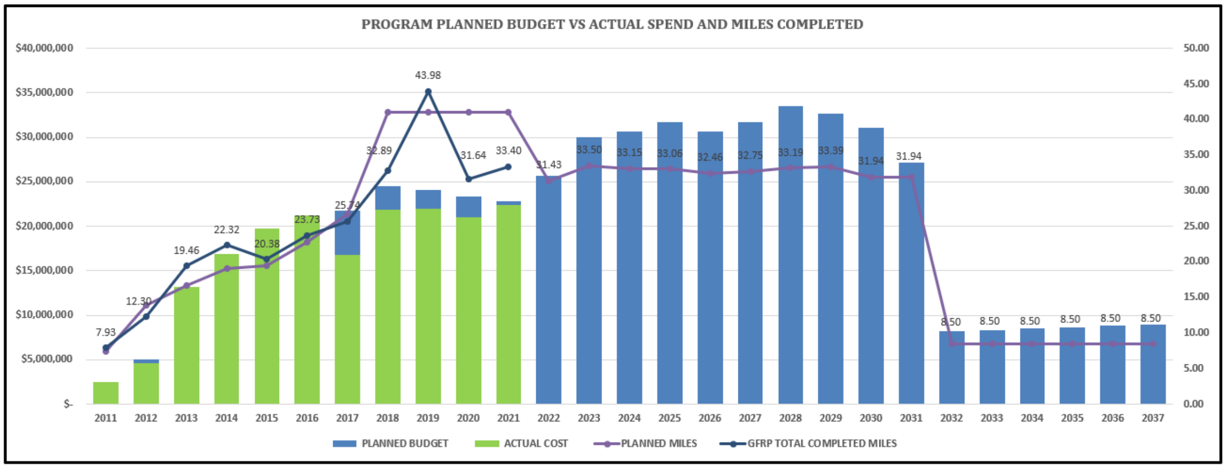
The Projected Leaks, Linear Regression Model (above) demonstrates continued risk reduction through pipe replacement and covers the combined service territory (WA, ID, and OR). The modeling does not indicate a need for any material adverse changes in the program's timeline and supports extending Oregon an additional five years (due to already mentioned delays in Oregon). Risk for a catastrophic failure remains but the chances of such an event occurring are remote. In addition, the leak survey program serves as an additional mitigant as many of the past leaks have been detected, through the program, and remedied.

Program is on schedule to be completed in time in WA and ID. Additional time is needed in OR (2037):

Completion in WA and ID is expected by 2031; the project remains on schedule for both states. Oregon is expected to be completed by 2037. As noted in the Executive Summary, delays have occurred in Oregon due to COVID-19 impacts, municipal permitting delays, wildfire, and 3rd party contractor strikes, to name a few.

The chart below measures mileage completed (to date) and mileage planned against budget costs. [13]

[13] Source: GFRP Historic Program Analysis Asset Management V.2



The table below shows progress in aggregate terms by listing out the amount of pipe in the ground at the end of 2011 versus 2021. It highlights the slower progress being made in Oregon but overall demonstrates the program is on track for completion. It should be noted, however, budgets are tentative and subject to revision, based on[14]:

- Schedules and miles completed (prior year)
- Distribution Integrity Management Plan (DIMP) Analysis
- Budget Constraints

Any material changes in dollar amounts made available to the program could limit its progress going forward.

State	**Pipe Remaining (EOY 2011, Miles)**	**Pipe Remaining (EOY 2021, Miles)**	**Percent Complete[15]**
Washington	353	208	41%
Oregon	253	178	30%
Idaho	131	77	41%
Total	737	463	37%
Opportunity Work		*385*	*48%*

- *Note. As of January 2022, an additional 78 miles of pipe replacement has been completed, outside of the program, through opportunity work done by local*

[14] Budget and actual costs incorporate all planned work within the program: major main work, minor opportunity work, STTR work, priority services, and Aldyl-A replacement (cross bore).
[15] Includes 'Good' miles. 'Good' pipe is pipe that was manufactured and installed in 1985 and 1986 and does not need to be replaced. It is found during the year through potholing and map editing. This amount is combined with the construction completed amount to arrive at the annual total.

districts, pipe verification and map editing. Therefore, the overall project is closer to being 50% complete.

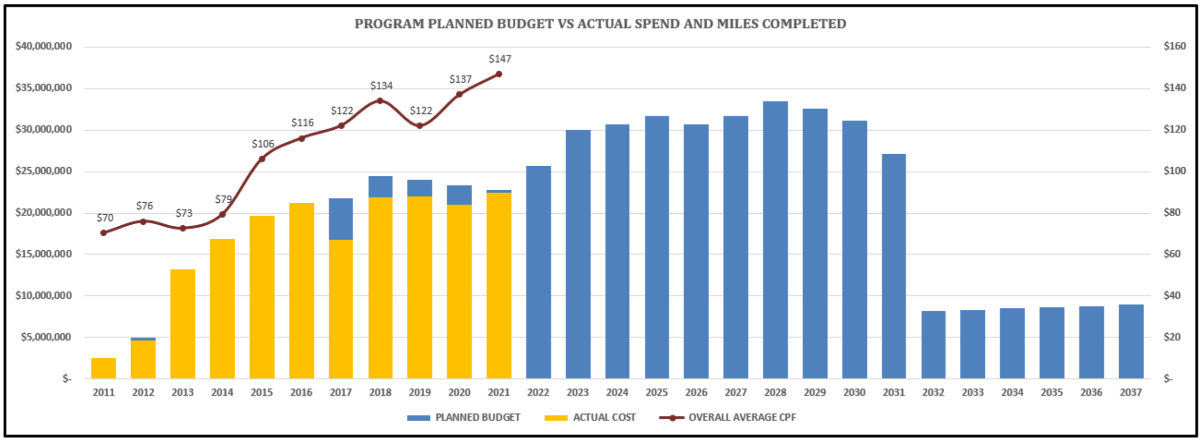
The program is getting more expensive as the cost per foot (CPF) has increased:

Replacing natural gas facilities decades after the initial installation, and after the subsequent development of the service areas is challenging. Replacement pipe must be installed in fully developed and occupied areas that consist of numerous below ground facilities, paved streets, sidewalks, arterials, landscaped residential neighborhoods, and hard-surfaced commercial developments teeming with daily traffic and other activity. New main pipe is most often installed by either “horizontal drilling” or open trenching. While horizontal drilling is far less invasive, both methods require cutting into existing pavement or other hard surfaces. Care must be taken to plan and locate the existing underground facilities to avoid damaging them, new service lines must be ditched into landscaped yards, etc., and all these features must be restored to unblemished service once the installation is complete.

During the first two years of the program Avista reported average per foot replacement costs ranging from $69 to $83 per foot. These costs included pipe replacement in hard-surfaced areas as well as areas of exposed soil, such as the shoulder of semi-rural roadways with limited adjacent facilities and road restoration. More recently, Aldyl-A pipe replacement project locations have been primarily located in suburban developments in which the right-of-way is fully built-out with paved roads and sidewalks and has required increased permitting stipulations. As a result of these conditions, pipe replacement costs have increased. In 2021, the average cost of main pipe replacement was $122/LF (per linear foot), with a low of $ $90/LF in Klamath Falls and a high of $155/LF in the City of Medford.

Avista continued to report its experience with replacement construction costs, in particular, as we experienced a trend on the part of municipalities toward more restrictive and expensive roadway restoration and traffic control requirements. Over the past several years these traffic control, pavement cutting, and remediation policies of local jurisdictions have had a significant impact on the scheduling, logistics, operational methods, extent of the area to be repaved, and the ultimate cost of pipe replacement. In Avista’s experience, this continuing trend to enforce more restrictive moratoria on cutting in newer arterials and streets, to require more stringent requirements for backfill and compaction, for patching or repaving of streets cut for pipe replacement, and traffic control requirements have had a substantial impact on installation costs.

The chart below shows the average cost per foot from 2011-2021 for all three states. The actual pipe replacement costs are higher in Oregon. The major element of the total cost disparity is related to road restoration requirements in Oregon jurisdictions. These higher construction costs are a direct result of municipally driven traffic control permit requirements (e.g. plate locks), material handling requirements that include 100% export and import of trench backfill materials (e.g. slurry backfill), significant soil compaction the width of pavement restoration, which averages 4 feet and can range from 2 feet up to 8 feet for segments of a project all which are beyond Avista's direct control.



- CPF has increased steadily since the program's inception.
- The program does not cost justify itself in that the actual and planned spends far exceed the dollar costs associated with a catastrophic failure.[16]

Summary of program changes for Oregon

While taking into consideration the extension of Oregon's Aldyl-A pipe replacement to 2037, there has been extensive analysis and research completed to ensure risk does not increase. As previously stated, various slowdowns have occurred which have impacted program timelines relating to work in Oregon. Impacts such as COVID-19, contractor strikes, contractor staffing issues, wildfires, municipal restrictions and municipal permitting delays have all created significant effects on operations and made replacement efforts much more challenging. Extending Avista's Aldyl-A replacement work in Oregon to 2037 will allow us the opportunity to balance affordability and overall impact to our customers. The data in this report supports that risk is continuing to be mitigated and that extending work in Oregon will not increase the risk of catastrophic failure.

[16] Cost associated with a catastrophic failure is $20,000,000 and is based on the following risk formula to determine its annual value: ***Pf * Pc * c, where Pf = Annual probability of failure, Pc = Annual probability of consequence, and c = consequence cost ($20 million).*** This annual amount can then be measured against the annual spend.

Gas Above Grade Pipe Remediation, ER3009

1.0 CHANGE REQUEST #1 – 8/25/23

Previous Requests	Requested	Approved
5-Year Plan	$	$

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
Jul - 2023	$4,608	$750,000	$(300,000)	$450,000

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	9/6/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

- It is projected that the program will end up approximately $300,000 under budget due to insufficient staffing at the beginning of 2023 that was caused by unplanned retirements at the end of 2022. Project planning, designing, and permitting through the first two quarters of the year were deferred until new staffing resources could be hired and sufficiently trained. As a result, the 2023 construction window to remediate these facilities has been condensed to a three to four month timeframe at the end of 2023, which isn't enough time to spend the entire budget.
- Gas Engineering is proposing to give back approximately $300,000 for 2023.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

-

1.1.3 Please reference analysis or information that support the problem and attach to this document.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

-

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

-

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

-

Gas Above Grade Pipe Remediation, ER3009

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

-

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Jeff Webb / Mike Yang	BC Owner	[illegible]	8/25/2023
Alicia Gibbs	BC Sponsor	Alicia Gibbs Type text here	Aug 2023
	FP&A		

Gas Above Grade Pipe Remediation, ER3009

1.0 CHANGE REQUEST #2 – 10/12/23

Previous Requests	Requested	Approved
5-Year Plan	$	$

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
Jul - 2023	$23,528	$450,000	$(150,000)	$300,000

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	10/31/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

- It is projected that the program will end up approximately $450,000 under the original budget due to insufficient staffing at the beginning of 2023 that was caused by unplanned retirements at the end of 2022 and a delay in hiring the replacements. Project planning, designing, and permitting through the first two quarters of the year were deferred until new staffing resources could be hired and sufficiently trained. As a result, the 2023 construction window to remediate these facilities has been condensed to a three to four month timeframe at the end of 2023, which isn't enough time to spend the entire budget.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

-

1.1.3 Please reference analysis or information that support the problem and attach to this document.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

-

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

-

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

-

Gas Above Grade Pipe Remediation, ER3009

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

-

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Jeff Webb / Mike Yang	BC Owner	Jeffrey A Webb	10/12/2023
Alicia Gibbs	BC Sponsor	Alicia Gibbs	10/12/2023
	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

ER 3007 - Gas Isolated Steel Replacement Program

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case. (Updated in August 2022)

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This business case is for follow-up mitigation work generated by isolated steel pipe inspections. Resulting work is required to be completed in either 90-days or 10-years as directed by the Code of Federal Regulations.

This program had a filed budget of $850,000 TTP for 2023. The budget is allocated between Washington, Idaho and Oregon construction areas based upon project need. Currently, about 90% of the budgeted replacement work for the Isolated Steel Program is completed in Oregon. In March 2023, the Gas Programs Team submitted a funds change request to Avista's Capital Planning Group (CPG) to support the need to perform additional isolated steel pipe replacement work. Through the year, the CPG approved an additional funding level of $1.25M for a total program budget of $2.1M. In general, dollars spent as part of ER 3007 transfer to plant the same year.

The type of work performed in these replacement jobs can be hard to predict ahead of time. At times, an expected simple isolated riser replacement or anode installation can become a full service replacement once the pipe is exposed and project is in-flight, as happened a couple times late in 2023. These types of projects add unanticipated costs to the program. As replacement jobs were completed and invoiced in 2023 there were increased costs to various projects associated with paving, traffic control and post-construction cross-bore inspections. These unforeseen cost increases attributed to an additional $150k above the approved $2.1M budget.

The planned transfer to plant was $2,100,000. The actual transfer to plant was $2,250,494.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The work associated with this program involves the mitigation of high-risk facilities with potentially hazardous and compliance related implications. An in-year funds request was submitted in March of 2023 and the Capital Planning Group approved an increase in total budgeted spend to $2,100,000 between April and July.

Capital spend for this program is reviewed and adjusted monthly. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, gas leadership agrees on submitting funds requests or releases, as necessary. Funds Requests are submitted to the company's Capital Planning Group (CPG) for consideration. Approved funds requests are included with this form.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets for this period.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X

DIRECTOR SIGNATURE:

X Alicia Gibbs

Gas Isolated Steel Replacement Program, ER 3007

EXECUTIVE SUMMARY

In accordance with a Stipulated Agreement with the Washington State Utility Commission (WUTC), and to maintain compliance with the Code of Federal Regulations 49 CFR 192.455, 192.457 and 192.465 Avista implemented an "Isolated Steel Identification and Replacement Program" (program) beginning in 2011. The initial goal of the program was to identify and remediate steel piping and risers that are isolated from or lack the necessary cathodic protection within Avista's Washington State natural gas pipeline systems. Inadequate cathodic protection can result in corrosion of steel pipe and ultimately leaks related to corrosion. Natural gas leaks on corroded pipe, especially at or near buildings and residences, can result in a threat to life and property. Gas leaks can result in unsafe environments for customers and potentially Avista's employees. As part of the program evolution, and to be prudent in our operations, our efforts in recent years have expanded into Avista's Idaho and Oregon service territories. Work completed under this program helps maintain Federal and State compliance requirements and results in a safer gas distribution system, both for the communities we serve and for Avista employees. Over the long term, this investment will help to reduce operating and maintenance costs for Avista as we will no longer be required to spend time and money locating and mitigating unknown isolated steel facilities.

Remediation efforts in Washington State were completed in 2021 and approved by the WUTC as outlined within a 2022 Closure Letter for the Stipulated Agreement. As this program has been completed in Washington State, the focus of the Gas Isolated Steel Replacement Program moving forward will be in Idaho and primarily Oregon. Avista has finished identifying isolated steel in Idaho and is in the early stages of identifying isolated steel in Oregon. Remediation of identified sections of isolated steel pipe is ongoing in both Idaho and Oregon to reduce the risk of hazardous leaks caused by continued corrosion of isolated steel pipe in our distribution system. Most of the remediation in Idaho has been completed with only a few known projects remaining. Due to the amount of isolated steel that needs to be identified and remediated in OR, this will need to be an ongoing program until the full scope can be better defined through the inspection process. Currently, the approved level of capital funding does not support completing the volume of inspections required to truly understand the extent of the work that will be generated in Oregon. The replacement jobs generated during inspection work often have a quick timeline for remediation. We require additional capital funding to be able to generate more replacement jobs in order to forecast and understand the full scope and duration of the Oregon Gas Isolated Steel Replacement Program.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/16/2017*
1.1	*Jeff Webb*	*Revisions*	*4/07/2017*
1.2	*Jenn Massey*	*Revised for 2020 Oregon GRC Filing*	*2/17/2020*
1.3	*Nick Messing*	*Updated to the refreshed 2020 Business Case Template*	*7/10/2020*
1.4	*Nick Messing*	*Updated to the refreshed 2022 Business Case Template*	*5/05/2022*
1.5	*Seth Samsell*	*S. Samsell took over Program and revised Business Case Template*	*8/25/2022*
1.6	*Shontelle Wilson/Seth Samsell*	*Updated to the refreshed 2023 Business Case Template*	*4/14/2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	5/2/2023

Gas Isolated Steel Replacement Program, ER 3007

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**3,000,000**	**3,000,000**
2025	**4,000,000**	**4,000,000**
2026	**5,000,000**	**5,000,000**
2027	**5,000,000**	**5,000,000**
2028	**5,000,000**	**5,000,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	R08 – Gas Programs
Business Case Owner | Sponsor	Seth Samsell / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

There is an unknown amount of "isolated" steel pipe in Avista's Oregon natural gas systems. Isolated steel pipe is defined as pipe that does not have adequate cathodic protection or is protected but may be isolated from a cathodic system. Cathodic protection is required by Federal Code to help prevent buried steel from corroding. Corrosion can cause leaks at or near service points resulting in conditions that may be hazardous to life and/or property. This program originally began in Washington State as result of a failed audit in which Avista was found to be in violation of code due to unknown and unprotected steel service piping. As a result, we entered into a Stipulated Agreement with the WUTC, to identify, document and replace all unknown sections of isolated steel pipe including isolated steel main, services and service risers within a specified timeframe. These efforts have been carried over into Idaho and are now also ongoing in our Oregon service areas.

Gas Isolated Steel Replacement Program, ER 3007

1.2 Discuss the major drivers of the business case.

The major drivers for this business case include the categories “Mandatory and Compliance” as well as aspects of “Customer Service, Quality and Reliability”. Isolated (unprotected) portions of steel pipe, including main, service pipe and risers, do not comply with the Code of Federal Regulations. Per Federal rules 49 CFR 192.455 & 192.457 steel gas pipelines installed below ground must be cathodically protected to prevent corrosion of the steel material. When steel pipe is found to be not cathodically protected, Federal rule, 49 CFR 192.465 states that the issue needs to be remediated promptly. Washington Administrative Code (WAC) 480-93-110 defines promptly as “within 90 days”. This is the standard that the original Washington program was based upon, and it is the recommended practice by the National Association of Corrosion Engineers (NACE). Isolated (protected) portions of steel pipe are allowed by Federal Code, if they are monitored every 10-years to ensure the cathodic protection is still adequate.

Per the initial Stipulated Agreement in Washington, Avista was required to replace all isolated steel, identified through the Washginton inspection program, within a period of 90-days (if unprotected) or 10-years (if protected) to eliminate the potential risk for non-cathodically protected steel and corrosion related leaks in the future. Keeping in line with this practice, when isolated steel pipes have been found through program inspections in Idaho and Oregon, we have historically replaced them to meet the requirements of 49 CFR 192.455 and 192.465. Avista has incorporated and maintained this standard of 90-day (isolated & unprotected) and 10-year (isolated & protected) replacement timeframes to stay compliant. The alternative to replacement, in order to maintain Federal and State compliance, would be to re-establish cathodic protection and monitor these locations every 10-years per 192.465. Not maintaining the effort to locate and remediate isolated steel pipe within the specified timeframes could mean that Avista would be increasingly out of compliance with mandatory Federal and State regulations. This is a significant risk and is a required action called out in Avista’s Integrity Management Plan.

Since the initial Washington program requirements have been satisfied, Avista has shifted the program forward in Idaho and is working primarily in the Oregon service areas to identify and remediate isolated steel pipe. Work under this program for Idaho and Oregon is currently being completed to the same standard as for Washington. Locating and mitigating isolated steel pipe will result in a safer gas distribution system for Avista’s customers as well as our employees. When steel pipes do not have proper cathodic protection, the risk of corrosion and related corrosion leaks become significantly greater over time. We are not able to predict the condition of the pipe or how long this pipe has been unprotected. We do know some of steel pipe has been in the ground since the 1950s. Natural gas leaks on corroded pipe, especially at or near buildings and residences, can result in a threat to life and property. Gas leaks can result in unsafe environments for customers and potentially Avista’s employees. In circumstances where a corrosion related leak might require an unplanned outage to repair, customer service, quality and reliability suffer as well. These risks only continue to increase the longer this isolated steel pipe remains in the ground and undetected.

Gas Isolated Steel Replacement Program, ER 3007

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed now to comply with the Federal and State regulations and Avista's standards as discussed in previous sections. Per Avista Gas Standards Manual Spec 5.14 "When facilities under cathodic protection are found with pipe-to-soil (P/S) potentials below adequate levels, the facilities must be scheduled for restoration. Areas shall be restored within 90-days from the date they are found below adequate levels of protection in Washington and should be restored within 90-days in Idaho and Oregon as a best management practice." The goal of this program, moving forward, is to maintain the same quality of work that was completed in Washington for the states of Idaho and Oregon. Failure to complete the program to this same standard may result in danger to life, property, and the environment. Other increased risks include operational and financial penalties determined by Federal and State regulators. These penalties could range from thousands of dollars to multi-millions of dollars depending upon the severity of the incidence or violation. There is no good way to predict what the severity of an incident or penalty might be. However, by maintaining and expanding this program, Avista is showing an effort to locate isolated steel within our natural gas system and to operate within Federal and State regulations. By operating in this manner, the intent is to reduce the risk of corrosion on steel piping systems and thereby reducing the chance for future leaks associated with these pipes. Work completed under this program results in a safer, more reliable natural gas distribution system in all the communities we serve, for Avista's customers as well as our employees.

It is important to clarify that additional inspection work (O&M) is needed now in Oregon to be able to better assess the remaining isolated steel risk and the best direction for the program. However, these inspections will create follow-up work (Capital) that will be required to be completed within either a 90-day or a 10-year timeframe to remain in compliance with the Code of Federal Regulations and Avista's Standards for Gas Construction. Failure to replace pipe or re-establish CP within 90-days or to meet other required compliance timeframes could lead to potential violations with the Oregon Public Utility Commission. Deferring the budget request will result in the ability to perform fewer inspections and will limit the Program's ability to forecast the full scope, timeline and risk associated with a likely significant compliance and integrity issue.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's organizational focus on our responsibility to maintain a safe and reliable infrastructure in all the communities we serve, for all our customers and for our employees who maintain these systems each day. By mitigating isolated steel pipe, we are staying in compliance with Federal and State regulations, remaining innovative, and improving our current systems. This program further shows our customers that we are a responsible operator that puts customer safety first. Corrosion related leaks can not only cause outages but can compromise the safety of Avista customers and our employees. As a best practice, Avista should continue with this program to prevent corrosion leaks on steel pipe and help prevent associated incidents or outages by proactively locating and establishing cathodic protection or replacing isolated steel pipe.

The Gas Isolated Steel Replacement Program is in line with meeting Federal and State code requirements. The program also follows Avista Gas Standards Manual Spec 5.14 Cathodic Protection Maintenance, as quoted above in section 1.3 of this Business Case justification. This program will locate and mitigate currently unknown pipe that is not adequately protected cathodically and is at high risk for corrosion. By working to comply with 49 CFR 192.455 and 192.465 this program works to maintain safe and reliable natural gas systems, and helps prevent future corrosion related leaks at or near buildings which places Avista's customers and employees at risk. All of this is in accordance with Avista's Standards and Integrity Management Plan.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

During the Washington program, beginning in 2011, approximately 175K inspections were completed resulting in over 4,780 follow-up jobs ranging from additional required inspections to full replacements of service risers or service lines. From these findings Avista determined that continuing this program will address significant risk in our Idaho and Oregon service territories as well. It is in Avista's best interest to address these risks sooner than later. Idaho inspections are now complete and there were approximately 1,500 follow-up jobs from over 58K locations inspected. There are only a handful of replacement jobs remaining in Idaho, and these should be completed over the next year or two.

Currently, of approximately 89K service locations in Oregon, more than 57K locations still require inspection. The nature of the program often requires multiple inspections at a single location. At this time, it is estimated that more than 120K visits will be required to complete the Oregon inspection process. Since Oregon inspections began (in 2020) we have been finding isolated steel replacement jobs at a rate 2 to 3 times that for Washington and Idaho. Because our sampling rate for steel inspections is small, relative to the entire Oregon system, it is unknown if this high rate of isolated steel discovery will continue in Oregon. With the information we have now it is estimated there may be anywhere between 5K and 20K jobs in Oregon that would require remediation within either 90-days or up to 10-years. At this time, service

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

replacement jobs are costing on average about $12K in Oregon, but we have seen as high as $25K depending on the circumstances involved. Replacement at these quantities and cost would result in a significant capital investment ($60M to $240M). While the inspection work is O&M, the remediation work is capitalized. Current capital funding levels limit the number of jobs that can be created each year from the inspections. Current operational resources limit the number of remediation jobs we can complete each year. Because of this, we are limited in the number of inspections we can complete, which only serves to perpetuate Avista's ability to understand the scale of the problem and plan for the risk associated with a known system integrity issue. We believe the proposed capital funding will help us to generate the information we require to fine tune these estimates and build the program scope and schedule. While doing all of this we will continue to reduce risk within our natural gas system both from an operational and a compliance standpoint.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

As the program is now complete in Washington state, the proposed solution for Idaho and now Oregon is to maintain similar standards and practices set out for the Washington program. The goal is to systematically identify and remediate all sections of isolated steel pipe and service risers in all our operational areas. Replacement of these isolated steel pipes and risers maintains compliance with Federal Code 49 CFR 192.465, WAC 480-93-110, NACE, and Avista's Standards. It also fulfills Avista's goal to maintain our responsibility of operating a safe and reliable infrastructure in all the communities we serve, for our customer's as well as our employees.

There are approximately 57K locations remaining in Oregon that require multiple inspections to determine whether they are isolated. Ideally, we would approach this program by completing all inspections over a 2-3 year period and at the same time be addressing the remediation efforts as follow-up in up to a 10-year timeframe, similar to Washington State. The challenge with this program is managing the budget and resources required to complete the amount of required replacement work within the required 90-day or 10-year timelines. We do not have enough information at this time to estimate the quantity of 90-day and 10-year jobs we will be required to complete. Our best estimates indicate there may be anywhere from 5K and 20K follow-up jobs created by the inspections. In order to fine tune these estimates, we need to be able to complete more inspections. Since the O&M inspections generate capital replacement jobs, we are requesting additional capital to support additional remediation work that will be generated by an increased number of inspections. This will provide better data to be able to forecast the full scope and timeline for the remaining program in Oregon.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits, or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

This business case is intended to address risk reduction and Avista's ability to maintain compliance in the states we operate within. The program is aimed at maintaining safe and reliable systems for our customers and not so much a cost benefit or return on investment. At this time, more information is required from the Oregon inspection program to be able to generate valuable risk and risk reduction analyses on isolated steel in Oregon. We believe that isolated steel is a significant integrity issue in our system and that the risk is significant enough that the investment should be made now to maintain compliance and eliminate these risks. The ultimate threat is a catastrophic event that would pose risk to life and property. That said, isolated steel pipe and service replacements do put new, more reliable plant in the ground as a capital investment which improves the overall reliability of our system.

The current requested amounts are being made based on the number of remaining jobs in Idaho and Oregon, estimating the number of unknown jobs in Oregon, comparing the average replacement costs in each state, and by reviewing previous years' budgets along with the volume of work completed by the program each year. In 2022, with an approved capital budget of $850K, additional approved requests of $280K, and additional spend we were able to complete approximately 150 replacement jobs at a final cost of approximately $1.5M. This level of replacement is not sustainable over the long term with the quantity of replacement jobs we anticipate from the Oregon inspection program. As stated in Section 1.5, it is estimated there may be anywhere between 5K and 20K replacement jobs generated in Oregon that would require remediation within either 90-days or up to 10-years. Currently, full service isolated steel replacement jobs are costing on average about $12K in Oregon. We have seen replacement jobs as high as $25K depending on the circumstances involved and these costs are only increasing. Replacement at these quantities and cost would require a significant capital investment ($60M to $250M) and additional resources to complete the work in the required timeframes. This is work that will need to be completed to stay in compliance and mitigate the risk. Deferring the work will only increase the overall costs of replacement and place us at a greater compliance risk.

This data is constantly changing as more inspection information for Oregon is gathered. As this happens the forecasting will be improved, and the business case updated to align requests moving forward with the amount of work required to mitigate isolated steel in all Avista's service territories.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Gas Isolated Steel Replacement Program, ER 3007

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	-	$0	$0	$0	$0	$0
O&M	Reduced Costs of Inspection and O&M Related Follow-Up	$0	$0	$0	$150K	$150K

The program goal is to identify and mitigate all the isolated steel pipe in our system which will eliminate the need to perform additional survey inspection work. We estimate there will be approximately 120K inspections required at over 57K locations. At current costs, this would be approximately $720K over the life of a 5-year inspection project or about $150K/year. Depending on the level of capital available, we might be able to support completing the inspections as soon as a 3-4 year period. This is the assumption shown above.

Over time, the program will also reduce or eliminate the need to have Cathodic Technicians performing isolated steel follow-ups created by the inspection orders. At the volumes we estimate now, this could be a savings up to about $50K/year that could be dedicated to other Cathodic Protection work within our systems. The timing of when this offset would be recognized is difficult to predict at this time without knowing the full scope of the project. However, we could potentially see these savings in as soon as 6-7 years. This would depend on the rate at which we find isolated steel, the number of jobs we can complete each year, as well as how long it would take for the Cathodic Technicians to complete all the follow-up work orders generated from the inspections.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	Cathodic Protection	$3000	$3000	$3000	$3000	$3000

Most of the offsets that would result by completing the isolated steel replacement work are direct and are described in Section 2.3. The program, however, will reduce the number corrosion leaks on isolated steel pipe as well as the number of issues encountered when identifying and repairing the cathodic protection system allowing Cathodic Technicians to focus on long term cathodic protection of the pipelines and not locations where we have inadequate protection. The estimated savings of $50K per year would apply in this case as well since it would be able to be cost refocused to higher priority work on the cathodic system. It is not likely these costs would be observed within the next 5-years of the program.

This program will also reduce the risk of outages caused by corrosion related leaks. Most outages related to a corrosion leak on isolated steel would only impact a single customer or service line at a time. It is estimated a single outage might cost $3000, but the probability of an outage being caused by a corrosion leak is relatively low.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1

One alternative to the proposed solution is to continue to locate and remediate isolated steel in Idaho and Oregon at current funding levels. The inspection program, over the past three years in Oregon, has focused on clearing and verifying PE riser locations (not isolated). It has been limited on the number of steel inspections completed in order to limit the number of follow-up jobs created to be within approved capital funding levels. Within a few years there will only be steel risers left to inspect. Maintaining current funding levels will only perpetuate a reduced quantity of inspections each year as costs continue to increase. We will only be able to complete inspections until the maximum level of created jobs is met based on program funding levels. This will, in effect, delay the identification of isolated steel in Oregon, which already exists in our systems, thus deferring our ability to identify and fix the problem.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Deferring the costs to replace or remediate these integrity issues will only extend the program for a potentially significant timeframe (i.e. decades). The identification and mitigation of these facilities is inevitable as they are not in compliance with Federal and State codes until they are cathodically protected. The longer we wait to identify the location of these isolated steel pipes, the higher the risk becomes that the unprotected steel pipes will corrode, develop leaks, and become hazardous to life, property, and the environment. Delaying the Oregon program would not align with Avista's current practice of mirroring the Washington program timeframe for Idaho and Oregon and would put Avista at a much higher risk of being increasingly out of compliance.

Estimated Cost of Alternative 1: $60M to $250M plus inflation and increased costs of replacement over the deferred timeframe. In addition, any additional O&M costs related to deferring the work.

Alternative 2:

An additional remediation alternative is to install temporary anode protection on service pipes to meet the compliance requirements of 49 CFR 192.465 around re-establishing cathodic protection within 90-days. Installing anode protection may allow for additional inspections to completed because it could extend the remediation timeframes. However, we only just recently determined that the installation of anodes on service piping can be capitalized. Anode installation may be a way to meet compliance, but these pipes may still need to be replaced within 10-15 years, depending on their condition and future cathodic evaluation. We do not know, and are not able to determine, the current condition of steel pipe in the ground or how long these pipes have been unprotected. The only way to know this would be to spend O&M dollars to dig all of them up and perform direct assessment on them, which would be very costly and disruptive.

We are still in the early stages of understanding how best we would utilize this alternative and whether it should be a best practice moving forward. Because of this, it is difficult to estimate what the costs might be. Assuming the installation of anode protection is approximately $1,200 per service, we might see initial capital costs in the range of $6M to $24M to mitigate these isolated locations. Future additional capital costs to replace pipe would need to be determined once the inspections were complete and we have a better understanding for the number of locations that would require service pipe replacement.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The Gas Isolated Steel Replacement Program will be successful if the unknown isolated steel riser/service count drops to zero in all Avista's service areas. This was a Washington requirement and is a best practice for Idaho and Oregon.

The Washington program eliminated all known isolated steel and Idaho has 17 open 10-year isolated steel service replacement jobs. Oregon has about 400 known isolated steel service replacement jobs open, but it is important to note that Oregon's numbers reflect the number of isolated steel replacement jobs currently open in our Maximo system. The ongoing inspection program is continuing to identify isolated steel in Oregon. Therefore, the job count in Oregon will increase as the inspection program and replacements continue. Newly identified sites will be added to the Oregon number for remediation. Approximately 89K services were identified in Avista's GIS system, which have been flagged for inspection in Oregon. The data and information for this program are housed and processed through an MXD system in AFM that is monitored by the Gas Programs department. The capital jobs or work orders created under ER 3007 are documented in Maximo and monitored by Gas Compliance Specialists.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Idaho mitigation projects should be completed in the next year or two. However, there is currently not a completion date set for the Oregon program. Ideally, we would pattern Oregon after Washington and establish a 10-year plan to complete the work, however the volume of work that may result from the Oregon inspections, may require more time to complete.

Additional inspection work (O&M) is needed to better assess the remaining isolated steel risk in Oregon. These inspections will create a significant number of 90-day and 10-year mitigation jobs. These jobs need to be completed to remain in compliance with the Federal Code of Regulations, State codes and Avista's Standards for Gas Construction. The current capital budget for this program does not support creating the required number of jobs to effectively progress the program. The level of capital funding also limits the ability to forecast the full scope and timeline (schedule) for the program, therefore limiting Avista's understanding of the associated risk in our Oregon service territories. The risk associated with this program is likely a significant compliance and integrity issue.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The governing committee for the program consists of the Manager of Gas Programs, The Isolated Steel Program Coordinator, the Manager of Gas Compliance (B54), the Manager of Gas Engineering (B51) and the Cathodic Protection group. This group helps to determine the direction of the program as it relates to both inspection work and capital replacement work.

The Manager of Gas Programs (R08) and the Isolated Steel team are responsible for this business case as well as monitoring and administering ER 3007 – Gas Isolated Steel Replacement Program. Gas Programs is also responsible for monitoring and administering the inspection process. The inspections are completed on a separate O&M budget, but they generate the jobs that are created as part of this capital replacement program. The data and information for the inspection program is documented in the ArcGIS system as part of an MXD program. The capital jobs or work orders created under ER 3007 are documented and tracked in Maximo.

Each new year, Gas Programs and the Isolated Steel team distribute the approved capital spend to each of the local construction districts to complete replacement projects in their respective areas. As these replacement projects are completed the costs are reported back through Gas Programs each month. This information is used to forecast current and expected remaining program spend for the year. These results are reported back to accounting and the Capital Planning Group through the Manager of Gas Engineering. This monthly reporting is used to identify whether budget targets are met and to track overall completion levels in each area. Changes to the business case or any funds returns/requests are also submitted through Gas Engineering. All these groups report to the Director of Natural Gas.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Isolated Steel Replacement Program* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeff a Webb	Date:	4/28/23
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	4/28/23
Print Name:	Alicia Gibbs		

Gas Isolated Steel Replacement Program, ER 3007

Title: Director of Natural Gas

Role: Business Case Sponsor

Signature: ______________________ Date: ____________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

ER-3007 <Project Name>

1.0 CHANGE REQUEST #1 – 2/28/2023

Previous Requests	Requested	Approved
5-Year Plan	$850,000	$850,000

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
02-2023	$114,660	$850,000	$2,000,000	$2,850,000

Type of Change	In-year Update
Primary Reason for Change	Scope Change
Response needed by	3/31/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

The Gas Isolated Steel Inspection and Replacement Program has shifted it's main focus into Oregon as the program closed out in Washington and Idaho in 2022. Initial inspections, completed in Oregon last year (1,162 steel service locations were inspected in 2022), reveal there is likely a large need for replacement work related to cathodically isolated (unprotected) steel pipe. Based on the inspection statistics from last year, the remaining 61,624 inspection locations in Oregon could generate around 10,000 follow-up replacement jobs that would need to be either completed within 10 years or 90 days depending on the compliance situation. Of those 10,000 jobs, we estimate as many as 2,500 could result in 90-day jobs.

Oregon Operations indicate their resources are capable of handling between 250 to 300 90-day replacement jobs in 2023. The additional $2,000,000 in funding would allow more inspections to be completed (approx. 4,250) and their associated replacement jobs according to the ability of the Oregon operational resources. The more inspections that can be completed in 2023, the more fully the program will be able to understand the extent of the work that is likely to be generated and a more accurate plan can be forecasted for future program costs and duration.

ER-3007 <Project Name>

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

This work is needed now in order to better understand the scope and risk associated with the Isolated Steel Inspection and Replacement Program for Oregon so that a more comprehensive plan can be developed to manage the risk. Additional inspection work is needed to better assess the remaining isolated steel risk, but these inspections will create 90-day replacement jobs that will need to be completed to remain in compliance with the Federal Code of Regulations and Avista's Standards for Gas Construction. Failure to complete the 90 day jobs in their compliance timeframes could lead to potential violations with the Oregon Public Utility Commission. Not completing or deferring the budget request will result in fewer inspections and will limit the program's ability to forecast the scope and risk associated with a likely significant compliance and integrity issue. This will also limit Avista's understanding of how best to manage the associated risk.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Analysis provided in Section 1.1.1 and 1.1.2.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

No additional business resources or functions are anticipated to be impacted by this change request.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

One alternative would be to temporarily install an anode on each additional isolated steel service found during the inspection process. This would allow the timeline for this work to extend into 2024. However, the use of the temporary anodes is not considered a recommended practice by NACE or Avista's Cathodic Protection Department. The anodes are potentially only protecting a small portion of the existing service pipe and for a limited timeframe. Periodic inspection at these locations would be required until the pipe replacement can be completed. There is still a risk for a related corrosion leak to develop on the isolated steel pipe. All of the work related to this alternative would be considered O&M cost for the existing system. These O&M costs are not budgeted.

A second alternative would be to stop inspection work once the number of 90-day jobs created reached the forecasted limit for the current budget (60 – 70 jobs). This option would keep costs for the program within budget, but it would limit the number of inspections (approx. 1,225) that could be completed in 2023 and negatively impact the program's ability to forecast future project costs and planning.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

Isolated steel consists of a gas service, riser or mainline pipe (steel) that does not have adequate cathodic protection per the Code of Federal Regulations (CFR) Section 192.455 and 192.457. This pipe is at a high risk of developing corrosion related leaks which could be a potential hazard to Avista customers and property. Full replacement of these facilities is recommended in order to mitigate the risk and be in full compliance with State and Federal regulations.

ER-3007 <Project Name>

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

N/A

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Brian Schultz/Jeff Webb	BC Owner		
Alicia Gibbs	BC Sponsor	Alicia Gibbs	Emailed approval on 3/3/23
	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

ER 3005 - Gas Non-Revenue Program

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This business case addresses minor projects on the natural gas distribution infrastructure (e.g., replacing services, lowering mains and services, repairing leaks, etc.) as well as replacing damaged equipment. As such, this work is often reactionary due to failure or protection against future failure and often discovered when abnormal operating conditions are encountered in the field. Since this work is mostly reactionary, the budget levels are based on historical spend levels. The cost to do this work has increased due to the rise in contractor labor, materials, restoration requirements, and traffic control.

The planned transfer to plant was $8,500,010. The actual transfer to plant was $10,779,650.

Overall, our variance was due to an unforeseen increase in workload that had to be completed to maintain reliability and safety for our customers, higher than budgeted labor costs, and an unprecedented increase in material costs.

This business case was monitored through the year. In August and October, the Avista Capital Planning Group approved additional funding for the above-mentioned cost impacts.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Capital spending levels are reviewed monthly. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, gas leadership agrees on submitting funds requests or releases, if necessary. Those funds forms are submitted to the company's Capital Planning Group (CPG) for funding consideration. Approved Business Case Funds Request(s) are included with this form.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets for this period.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Jeffrey A Webb

DIRECTOR SIGNATURE:

X Alicia Gibbs

Non-Revenue Program, ER 3005

EXECUTIVE SUMMARY

The work completed under this Business Case is typically unscheduled and is initiated by either customers or Avista maintenance crews. Gas Engineering establishes the overall budget based on historical spend patterns and reports monthly updates to the Capital Planning Group based on feedback from the Local Districts. Gas Engineering is responsible for projects under ER 3005 that require substantial design efforts such as farm tap retirements, highway or river crossings, and replacing steel pipelines with plastic pipe, but the local Districts manage the work.

The work in this annual program is mostly reactionary, unscheduled work and is difficult to predict aside from using historical trends. The following situations are typical triggers for work in the program: shallow facilities found by excavation (the excavation may or may not be related to gas construction), relocation of facilities as requested by others (except for road and highway relocations), leak repairs on mains or services, farm tap elimination, and overbuilds. Gas Overbuilds (ER 3006) are now part of this Business Case starting in 2024. The previous Business Case supporting overbuilds is ending, since all known overbuilds in Oregon have been remediated with the exception of the projects in the Medford District. Unforeseen overbuild projects will likely only come up occasionally, which is why this category of work is being added to this Business Case.

Customer related benefits include reduced operations and maintenance (O&M) costs and improved safety and reliability. Ensuring facilities are installed at the proper depth and in locations where maintenance can be performed improves safety for customers and company personnel. Leak rates are reduced when new plastic pipe is installed, versus leaving the older steel pipe in-place. When reducing leak rates, it also reduces unscheduled outages due to performing leak repairs and therefore raises customer satisfaction. The business needs and solutions identified in this Business Case impact gas customers across all of Avista's service territories.

Non-Revenue Program, ER 3005

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/16/2017*
1.1	*Jeff Webb*	*Updates to initial draft*	*4/05/2017*
2.0	*Jeff Webb*	*Revised for Oregon 2020 GRC filing*	*2/17/2020*
3.0	*Jeff Webb*	*Updated to the refreshed 2022 Business Case Template*	*5/31/2022*
3.1	*Shontelle McGrath*	*Updated to the refreshed 2023 Business Case Template*	8/14/2023
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*9/29/23*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**9,682,000**	**9,682,000**
2025	**9,972,000**	**9,972,000**
2026	**10,272,000**	**10,272,000**
2027	**10,580,000**	**10,580,000**
2028	**10,897,000**	**10,897,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	B51 / Gas Engineering
Business Case Owner | Sponsor	Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 / Gas Engineering
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The work in this annual program is mostly reactionary, unscheduled work and is therefore difficult to predict aside from using historical trends. The following situations are typical triggers for such work: shallow facilities found by excavation (the excavation may or may not be related to gas construction), relocation of facilities as requested by others (except for road and highway relocations), leak repairs on mains or services, remediation of cathodic protection (CP) issues, farm tap elimination, and overbuilds. Each of these work types have different problems that are being addressed and are further described below. Customer related benefits include reduced operations and maintenance (O&M) costs and improved safety and reliability from having facilities at the proper depth and from reduced leak rates of new plastic pipe versus older steel. The business needs and potential solutions identified in this Business Case impact gas customers across all of Avista's service territory.

When <u>shallow facilities</u> are discovered, an appropriate response to the situation is determined by Local District Management. A shallow gas facility is defined as not buried to the proper depth (having less cover and protection than is required). If the response to the situation is capital in nature, then the repair is funded from this program. These types of projects allow Avista to remain in compliance and operate the gas facilities in a safe and reliable manner.

If <u>requested by others</u> (typically customers) to relocate facilities, Avista is bound by tariff language to do so at the customer's expense. Under certain circumstances, Avista may choose these opportunities to perform additional work beyond the immediate request to improve or update the gas system. Local District Management and field personnel will evaluate the circumstances and make an appropriate decision based on a holistic view of the situation. Guidance to help evaluate the scenario is established in the Company Gas Standards Manual. An example might be to replace an entire existing steel service with modern plastic material instead of just replacing a small section of the steel service that conflicts with a customer's home improvement project. This would eliminate the possibility of future deficiencies with the cathodic protection system on the steel pipes and reduce future maintenance related to that steel service. The charges for this additional work are put against this program.

When <u>leaks</u> are found on the gas system, it is sometime advantageous to replace a section of main or service as opposed to repairing the leak with a temporary leak clamp. The Local District considers the long term impacts when possible, not just addressing the immediate concern when determining the right thing to do in each of these situations. This type of betterment falls under this program.

If a section of steel main is found to be <u>isolated electrically from the CP system,</u> a CP Technician will evaluate the situation and give directions to the district to fix. If the solution is a capital main replacement, it will fall under this program. Isolated steel services fall under ER 3007.

A single service farm tap (SSFT) installed on a high pressure main is a common way to provide gas service to a small number of customers. The alternative is to install distribution main from an adjacent distribution system to serve the customer which may be cost prohibitive at the time. Many of these farm taps are reaching the end of their service life or need to be replaced for maintenance reasons. In areas of high concentrations of farm taps that have maintenance concerns, it is sometimes advantageous to rebuild one of them as a traditional regulator station (pressure reduction station), install distribution main to the other services from the adjacent farm taps, and then retire the other farm taps. This reduces O&M by having fewer stations to maintain and increases safety by having fewer above grade facilities that are exposed to potential vehicular damage.

Overbuild conditions usually occur when a structure is placed or constructed over an existing gas pipe. The close proximity of these structures makes gas system maintenance and inspection difficult, can be against state and federal code, and can be a potential safety hazard for the occupants.

Figure 1 shows how the budget is typically spread across the different project types discussed above.

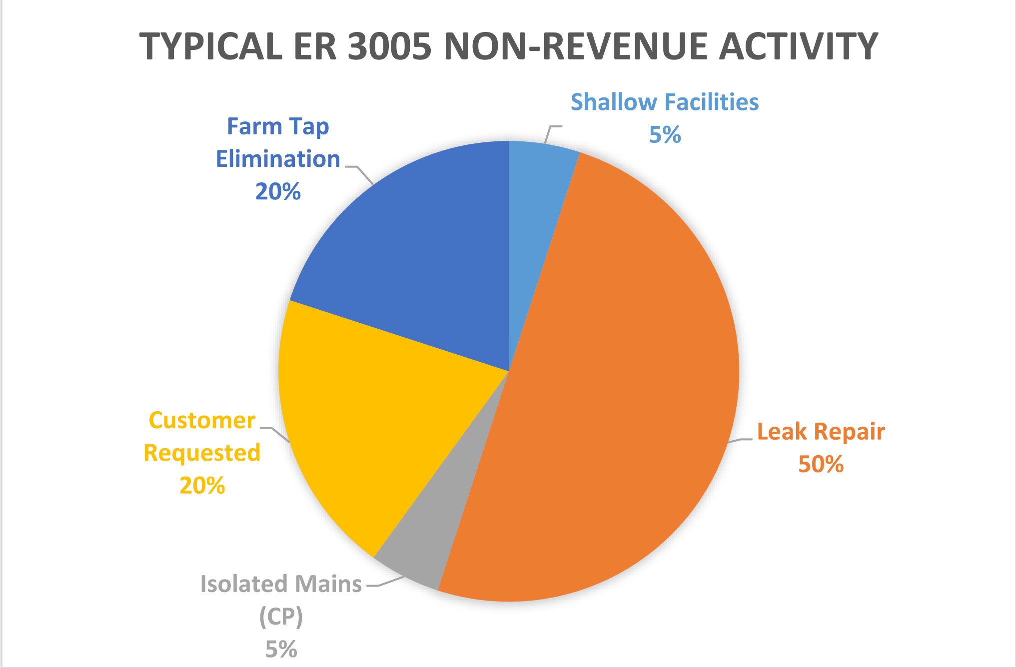


Figure 1. ER 3005 Spend by Project Type

1.2 Discuss the major drivers of the business case.

Due to most of this work being unscheduled replacement, the major driver is Failed Plant & Operations. The percent of Customer Requested work is small compared to the other work in this program.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Each different type of problem addressed under this Business Case mitigates different risks.

Shallow facilities – Lowering gas mains and services is not required by Federal Rules, but it is prudent. It reduces the risks of damage caused by excavation over and around the gas facilities. This is critical because damage from excavation is the highest risk to gas facilities. Excavators are expecting gas pipes to be at the depths they are originally installed at. When they are shallow because of grade changes that have been caused by others since installation, there is an increased risk of damage and threat to public safety.

If not approved, Avista would experience higher instances of pipe damages and associated gas leaks.

Requested by others & leak repair – Betterment of the gas system when opportunities arise is the prudent way to operate a gas distribution system. Mobilizing crews and equipment to a site often covers the bulk of the costs for small projects, so making the most of their time once on-site is a practical way to operate. Betterments as described above are driven by Company Standards and best practices.

If not approved, we would miss the opportunity to better the system while crews are already on-site doing work. This is shortsighted because we increase the chances of having to be back at the site to remedy other maintenance items later. The decision to simply repair the leak or perform the customer requested work (quickest and easiest thing to do) eliminates the chance to improve the system as a whole, while increasing the chances of having to be back at the site later to fix another leak or maintenance concern. If leaks are not repaired, the release of green house gases can negatively impact the environment and they must be monitored and re-evaluated on a periodic schedule to ensure they are not becoming a greater hazard to the public.

Isolated mains (CP) – Electrically isolated portions of steel main will be replaced as required to meet the requirements of Federal code 49 CFR 192.455 & 192.457. This is a safety related requirement as a steel pipe will corrode if it does not have sufficient CP on it.

If not approved, Avista will be at risk of fines for being out of compliance and the steel piping system will not be safe for the employees and customers.

Farm tap elimination – When there are many farm taps located near each other and when those stations have reason to be rebuilt, then it is wise to rebuild just one of them and install distribution main to the other stations to provide a new source of gas. This allows the adjacent (old) farm taps to be retired, reducing O&M and improving public safety. Triggers for rebuilding a farm tap may include: replacement of inadequate or obsolete equipment that is no longer supported, poor location of station (safety concerns), replacing leaking threaded connections with welded connections, inability to perform proper maintenance, and capacity constraints. Customers benefit from these types of projects by having a safer, well maintained distribution system. Also, this is a prudent way to manage resources because many deficiencies at stations can be remedied under just one projectIf Avista is not allowed to optimize the gas distribution system by reducing the number of farm taps that are maintenance intensive, then eventually more staff will be required to perform this federally mandated maintenance work. Additionally, farm taps are normally located between the driving lane and the property line, are low profile, and are sometimes difficult for the public to see. This puts them at risk of vehicle damage, so having fewer of them on the system helps to improve safety.

Overbuilds – Overbuilt gas pipes pose a safety risk for occupants in the area. Leaking gas can accumulate under mobile homes and storage sheds. If the overbuilt pipe is not relocated, Avista could also be at risk of fines due to being in violation of state or federal codes.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's values of being Trustworthy and Innovative. Each project completed under this program addresses a customer or safety concern while simultaneously bettering the gas system. Completing these types of projects shows that Avista makes wise, long-term decisions and takes steps to optimize the gas system when the opportunities arise. We prioritize customers through this work because it results in a safer, more reliable gas system. In addition, by completing customer requested work, we let customers know that their interests are important to us.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The work completed under this Business Case is reactionary. Projects are discovered throughout the year and resolved promptly thereafter. Most of this work is managed at the local district level, and Gas Engineering does not get involved with the individual projects.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Each project and solution are unique. Below are common solutions to each type of project.

<u>Shallow Facilities:</u> For gas facilities that are discovered to be shallow, the solution is to lower the facilities. This is typically achieved by either lowering the facility in-place or installing new facilities at an appropriate depth and abandoning the shallow facilities. This ensures adequate protection of gas facilities to reduce the risk of excavation damages.

<u>Requested by Others & Leak Repair:</u> When customer requested work and leak repairs come in, the request is reviewed, and the local gas system is looked at to see if there are any recommended improvements. If there are potential improvements, the Local District Manager uses their judgment, the Company Standards, and best practices to develop a solution. Oftentimes, improving the system by installing new gas facilities is a better option than simply repairing or relocating a small section of pipe. This improves the safety of the gas system and reduces the chances of returning to the same location to address additional safety or maintenance concerns in the future.

<u>Isolated Mains (CP):</u> When electrically isolated portions of main are discovered, the solution is to install a method of cathodic protection (CP) to ensure the pipe is protected. The method of CP remediation depends on where the isolated main is located and is determined by the CP Technician. Ensuring steel pipe is properly protected from corrosion is required by Federal Code. By addressing isolated mains, we reduce the risk of steel pipe corroding and leaking. In addition, not addressing isolated mains would result in Avista being subject to fines for not meeting Federal Code requirements.

Farm tap elimination: When there are several farm tap stations located near each other and one or more are due to be rebuilt, the most beneficial solution is to rebuild one station and install distribution main to the other station locations. This allows the other farm tap stations to be retired, reducing future O&M and improving public safety. Many deficiencies can be addressed through one project using this approach.

Overbuilds: When pipe is discovered under a mobile home, building, carport, or other structure that may entrap gas, the solution is to relocate all facilities that are overbuilt and abandon the overbuilt facilities (assuming the structure causing the condition can't be moved). This reduces the safety risk of gas entrapment and ensures gas facilities are installed in compliance with codes and best practices.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Each type of project completed under this program reduces risk, and some also reduce future O&M costs.

Shallow facilities: The risk of damage to gas facilities is higher for shallow facilities. Excavators expect gas facilities to be at the current, standard burial depths. This is not always the case for facilities in locations where grade changes have occurred since installation. External damage by excavation is one of the highest risks to gas facilities. By lowering shallow facilities when they are discovered, the risk of damage by excavators is reduced.

Requested by others & leak repair: By completing system enhancements when company crews are already onsite completing work requested by others, the risk of customer dissatisfaction is reduced. If only the bare minimum work were to be completed, there is a risk of having to return to the same site later for additional maintenance. This is also a more cost-effective way to operate, as the cost of mobilizing a crew is most of the project cost. Similarly, with leak repairs, it is likely that if the leak is simply patched that a crew will need to visit the same location in the future for additional maintenance. By improving the system in response to a leak, the risk of having to revisit the same site in the future is

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

reduced. Again, this also reduces future O&M costs and the potential for greenhouse gas emission related to gas leaks.

Isolated Main (CP): By addressing isolated steel main, we reduce the risk of pipe corroding. In addition, ensuring steel pipe is protected is mandated by federal code. Avista would be at risk of federal fines if isolated mains were not addressed.

Farm tap elimination: There are different reasons a farm tap may be due for replacement. These include: inadequate or obsolete equipment that is no longer supported, poor location of station (safety concerns), replacing leaking threaded connections with welded connections, inability to perform proper maintenance, and capacity constraints. By rebuilding and/or eliminating station locations that face these concerns, several types of risk can be reduced. If a station has inadequate or obsolete equipment and it were to fail, there is a risk of an unplanned customer outage due to the station failure. There are a few risks associated with stations in poor locations, many of these sites are located just off the roadway, between the traffic lane and property line. For these stations, there is a risk of vehicular damage to the station, as well as a safety risk to Avista personnel while performing required maintenance. If proper maintenance cannot be performed, Avista is at risk of fines for not being compliant with mandated maintenance requirements. If a station has capacity constraints, there is a risk of unplanned customer outages if a station cannot support all downstream customer loads. In addition, by eliminating farm tap locations, future O&M costs associated with required station maintenance can be eliminated.

Overbuilds: For gas facilities that are overbuilt, there is a safety risk. Gas can accumulate under structures, which poses a risk to public safety.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M	Temporary Leak Repair	$	$3	$	$	$

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$ -	$	$	$	$
O&M		$3,995,000	$3,995,000	$3,995,000	$3,995,000	$3,995,000

If the capital work under this Business Case was not available, a portion of Avista labor would likely be charged to expense work. The O&M cost offsets were calculated assuming half of the labor under this Business Case would be charged to other capital work, and half to expense. This is estimated to be $595,000 per year.

Additionally, if leaks were to be temporarily repaired when discovered, company crews would have to return to the leak repair site to install a permanent repair later. By permanently repairing leaks the first time, an estimated $3,400,000 per year of O&M costs are offset. These costs are associated with the temporary leak repairs. A temporary leak repairs costs about 80% of what a permanent repair costs.

CFR 192.465 & CFR192.720 determine how a gas utility manages leaks. The other portions of work associated with this Business Case are not mandated work. They consist of customer requested work, mitigating shallow gas facilities, and strategically replacing farm tap style regulators with IP main.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

For shallow facilities, the only alternative is to leave them in place. This is not recommended. The risk of excavation damage is higher for shallow facilities, and excavation damage remains one of the highest risks to gas facilities.

Alternative 2:

For work requested by others & leak repair, the alternative is to do the absolute minimum and only address the gas facilities that are either in conflict or leaking. This is not recommended because it is not a prudent way to operate a gas system. If system enhancements are not completed while crews are already mobilized and onsite, it is likely that crews will have to return to the same site to perform additional maintenance in the future on these aging facilities. This can end up costing more in future O&M costs than the cost of bettering the system in the first place.

Alternative 3:

There is no alternative to addressing isolated steel main. This work is mandated by federal code and would result in regulatory fines if not completed.

Alternative 4:

The only alternative to farm tap eliminations is to replace each farm tap as needed. This alternative is not advised. Farm tap stations require regular O&M maintenance. If Avista is not allowed to optimize the gas system by strategically eliminating farm taps where it makes sense, additional personnel may need to be hired to perform the federally mandated maintenance.

Alternative 5:

There is no alternative to replacing known overbuilds. Leaving known overbuilds in place would be a violation of code and standard practices.

Non-Revenue Program, ER 3005

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Each individual project under the different project types supported by this Business Case has a Maximo work order. Success can be measured by tracking all the completed work orders. Here are additional metrics for a few of the project types:

Shallow facilities: When damages occur on Avista's gas facilities, the cause for damage is documented. As shallow facilities are discovered and fixed, less damages should be correlated with improper depth of cover.

Requested by others & leak repair:

Customer satisfaction, or lack of complaints, due to not having multiple visits to the same address would indicate we are managing the system properly by bettering it when we have the opportunity. Lower leak rates over time due to newer gas facilities can also be tracked.

Farm tap elimination: As farm tap stations are eliminated, success can be measured through lower O&M costs associated with station maintenance.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The work in this program is comprised of small projects that are typically completed within the same month they are started. As such, the funds transfer to plant each month throughout the year.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Gas Engineering monitors the spend and reports back to the District Managers monthly. The oversight occurs through email and Gas Engineering will prepare the appropriate documents for the Director of Natural Gas to represents at the CPG should changes be needed throughout the year.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Non-Revenue Program, ER 3005* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeffrey A Webb	Date:	10/11/2023
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	10/12/2023
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

ER 3006 – Overbuilt Pipe Replacement

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Overbuilt pipe refers to gas pipes that either located directly under or very close to building structures. Except in rare case, Avista does not intentionally install gas pipes under structures. In most cases, overbuilt pipe occurs in mobile home parks where homes are moved over time. The close proximity of these structures makes gas system maintenance and inspection difficult, can be against state and federal code, and can be a potential safety hazard for the occupants.

The transfer to plant (TTP) variance of $604,990 (100%) was caused by an incorrect planned TTP value for the 2023 budget year. The "Filed 2023 Budgeted TTP Plan" for ER 3006 was originally set at zero dollars when it should have been set at $400,000 in accordance with the latest business case. An additional $200,000 of funding for ER 3006 was approved in October 2023 which increased the total approved 2023 budget to $600,000. When accounting for the correct 2023 budget number of $600,000 the TTP variance shrinks to $4,990 (<1%).

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Capital spending levels are reviewed monthly. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, gas leadership agrees on submitting funds requests or releases, if necessary. Those funds forms are submitted to the company's Capital Planning Group (CPG) for funding consideration. Approved Business Case Funds Request(s) are included with this form.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The $200,000 mid-year CPG funds change request avoided higher contractor costs associated with delaying the completion of work until 2024. See attached funds request document above for details.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Jeffrey A Webb

DIRECTOR SIGNATURE:

X Alicia Gibbs

Gas Overbuilt Pipe Replacement Program, ER 3006

EXECUTIVE SUMMARY

Overbuilt pipe refers to gas pipes that either located directly under or very close to building structures. Except in rare case, Avista does not intentionally install gas pipes under structures. In most cases, overbuilt pipe occurs in mobile home parks where homes are moved over time. The close proximity of these structures makes gas system maintenance and inspection difficult, can be against state and federal code, and can be a potential safety hazard for the occupants.

All the known mobile home parks with overbuilt pipe in Avista's Oregon districts were catalogued at one time, analyzed, and risk ranked as part of the utility's Distribution Integrity Management Program (DIMP). In addition to these known mobile home parks, with numerous overbuilt facilities, each local District (including those in Idaho and Washington states) periodically finds individual locations with newly overbuilt facilities. These projects and the risk associated with them are mitigated, over time, as part of the Overbuilt Pipe Replacement Program. As the number of known overbuilds in the company has decreased, the level of requested and approved funding has decreased as well.

This program is scheduled to be complete at the end of 2024.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Seth Samsell	Initial version	4/17/2017	
2.0	Seth Samsell	Revision for 2020 Oregon GRC filing	2/12/2020	
2.1	Tim Harding	Updated to the refreshed 2022 Business Case Template	9/1/2022	

Gas Overbuilt Pipe Replacement Program, ER 3006

GENERAL INFORMATION

Requested Spend Amount	$400,000
Requested Spend Time Period	Annually
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Tim Harding | Jody Morehouse
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Overbuild conditions usually occur when a structure is placed or constructed over an existing gas pipe. The close proximity of these structures makes gas system maintenance and inspection difficult, can be against state and federal code, and can be a potential safety hazard for the occupants.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The main driver for this program is Mandatory & Compliance. Resolving overbuilt gas pipes keeps Avista compliant with state and federal codes, and increases the safety of customers in the immediate project areas.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Overbuilt gas pipes pose a safety risk for occupants in the area. Leaking gas can accumulate under mobile homes and storage sheds. Relocating the gas piping is the most straight-forward approach to resolving the issue.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The locations of known overbuilt gas pipes have been catalogued and the completion of these projects is tracked by the DIMP Program Manager.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The DIMP study of known project locations can be obtained from the Gas Compliance group.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

This program replaces existing assets, however the asset condition is not generally a factor in project prioritization. This program replaces and relocates overbuilt gas pipes, regardless of the condition of the existing pipe.

2. PROPOSAL AND RECOMMENDED SOLUTION

The requested level of spending for this program is consistent with past years, and that level will allow the program to be complete at the end of 2024. A reduction in funding will extend the time required to complete all projects within the program.

Option	Capital Cost	Start	Complete
Recommended Solution, Complete planned projects at requested funding level	$400,000	January	December
Alternative Solution, Complete planned projects at a reduced funding level	$200,000	January	December

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

A DIMP risk analysis was performed on known overbuild projects by the Gas Compliance group. Information on this analysis is available from the Gas Compliance group.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

This capital program is focused on installing new gas mains and services, and retiring the previous overbuilt mains and services. This program does not significantly lower O&M costs. Instead, it is addressing a safety issue.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

None

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The alternative is to leave known overbuilds in place. This is a violation of code and standard practices. Only in rare cases is gas piping intentionally installed under a structure. The gas pipes addressed by this program were never intended to be built over, and therefore were not installed to comply with the special requirements needed to make such an installation compliant with code and Avista's Gas Standards.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

Projects completed within this budget will be transferred to plant upon completion, typically within the same year they are started.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program aligns with Avista's organizational focus to maintain a safe and reliable infrastructure to achieve optimum life-cycle performance, safely, reliably, and at a fair price for our customers.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

This program addresses a known safety issue. A thorough evaluation was performed by the DIMP group to validate the need for this program. Construction on this program will be complete at the end of 2024.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders include Gas Engineering, Compliance, Integrity, and Operations.

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

This program budget is overseen by Gas Engineering. Construction activities are overseen by Gas Operations. Projects are prioritized with input from the DIMP Program Manager, the impacted Operations Managers, and Gas Engineering.

3.2 Provide and discuss the governance processes and people that will provide oversight

DIMP risk scores are assigned to each proposed project. The highest-ranking projects are generally completed first, but some flexibility is required to ensure that specific operations groups are not overloaded during any given year. Gas Engineering oversees the program budget and reports on spending monthly.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

At the beginning of each year, the prioritization process is completed and the program budget is divided between offices. This information is formally handed off to the operations offices at that time. Rarely will anything change for the rest of the year. Gas Engineering reviews program spending with the operations offices on a monthly basis to keep within the program budget. Monthly updates are documented via email and fund requests are made using the appropriate forms from the CPG.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Overbuild Program ER 3006 and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeffrey A Webb	Date:	9/1/22
Print Name:	Jeff Webb / Tim Harding		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Jody Morehouse	Date:	9/1/2022
Print Name:	Jody Morehouse		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Gas Overbuilt Pipe Replacement Program, ER3006

1.0 CHANGE REQUEST #1 – 10/6/2023

Previous Requests	Requested	Approved
5-Year Plan	$812,000	$812,000

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
September - 2023	449,607	$400,000	$200,000	$600,000
Alternative Funding Option #2 (Pavement Only) =			$80k to $120k	$480k to $520k

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	10/31/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

- The original $400,000 budget for 2023 was determined based on historical spending within this program and outdated construction costs.
- Over the past year pipeline contractor costs have increased between 20% to 30% across the board on all services, and similar increases are being seen for paving and flagging contractors.
- The project having the largest impact on the budget is a major gas overbuild project in Central Point, OR (301 Freeman Rd) to fix around 4,000 ft of main piping and 42 services. The project is currently 75% completed and remaining costs are expected to exceed the overall program budget by around $200,000.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

<u>FUNDING OPTIONS:</u>

1. An extra $200,000 to complete all the work at 301 Freeman Rd is necessary to account for current cost overruns, remaining pipeline work, and to complete pavement restoration within neighborhood.
2. At a minimum, $80,000 to $120,000 funding is needed in 2023 to cover current cost overruns ($50,000) plus estimated pavement restoration of $30,000 to $70,000. Highly recommend funding at least this request so that pavement restoration can be completed.

<u>RISKS:</u>

- Deferred funding has delayed the restoration of customer driveways/roads used to access all of the residences, which could eventually lead to a lawsuit against Avista. Customer’s in the neighborhood are currently filing complaints with Avista and there is a risk these complaints could get elevated to the Oregon Public Utilities Commission. In addition, loose gravel from the unrestored areas is causing damage to vehicles and is a

Gas Overbuilt Pipe Replacement Program, ER3006

significant safety concern (i.e. tripping hazard) for the community's elderly population. Funding option #2 would resolve these critical risks.
- If service tie-over work is not completed now, then the main piping and services at 301 Freeman Rd cannot be retired/abandoned. This extends the timeline of operating gas piping that is non-compliant and at a higher safety risk of allowing migrating gas to leak into structures. Piping located under structures are also more difficult to inspect and maintain. Funding Option #1 would resolve this risk.
- The piping at 301 Freeman Rd is also pre-1984 Aldyl-A plastic material, which is at a greater risk of leaking. The combined risk of being underneath residential structures (high consequence) and pre-1984 Aldyl A piping (high probability) makes this a high priority replacement. Funding Option #1 would resolve this risk.
- Avista's current contract with Michels Utility Services expires at the end of 2023, so it's possible that additional time and cost would be wasted bringing a new contractor on board and having them pick-up where the last contractor left off. Funding Option #1 would resolve this cost increase risk.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

- See ER 3006 Business Justification Narrative for background information
- See ER 3008 GFRP Aldyl-A Business Justification document and/or 2012 white paper for background information on the elevated leak risk of Aldyl-A piping.
- 49 CFR Part 192 Code (LINK) requirements for installing service lines under buildings
- Michels Utility Services Pricing sheet available upon request.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

- The gas overbuilt piping being replaced at 301 Freeman Rd is pre-1984 Aldyl-A plastic material, so this work eliminates a site from GFRP's project list. The reduction in GFRP's future capital budget outlook is approximately $475,000 (Today's dollars).
- Successful completion of the 301 Freeman Rd project will allow for proper leak survey inspections.
- No O&M cost reductions

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

- Explored having GFRP use funding from ER 3008 to help fund cost overruns at 301 Freeman Rd since the project is eliminated a large section of pre-1984 Aldyl-A pipe. Currently there is no funding available within ER 3008 to make up for this extra cost.
- Stopping work until next year was considered, but the impact of leaving unrestored hard surfaces, higher risk piping in the ground, and burdening the local community was deemed to not be an appropriate option. Stopping work would also leave all high risk piping in service and under current structures.
  - Costs for next year could also be more expensive.
  - Unknown cost, timing, and work quality risk if Avista does not renew Michels Utility Services contract after 2023.
- The reduced funding Option #2 (i.e. restoration only) from section 1.1.2 would still result in many of the same issues stated in the previous bullet item, but it would resolve the most significant concerns within the community. This would still create higher costs next year since multiple restored (i.e. paved) locations would need to be re-excavated, but it would mitigate the complaint and lawsuit risks.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

- Additional funding to complete the work this year will provide the lowest overall cost, eliminate customer complaints, mitigate numerous existing safety risks, and eliminate customer complaints. Stopping work and starting next year could result in higher

contractor costs, wasted time/money getting a new contractor up to speed, numerous customer complaints, damaged customer vehicles, tripping hazards, and possibly even lawsuits.
- Completing the work this year allows for Avista to eliminate non-compliant and higher risk pipe in an earlier timeframe. This reduces the risk of future fines, emergency response, legal action, etc. if something were to happen on this pipeline.
- Deferring work to 2024 would anger customers and non-customers living in the 301 Freeman Rd community, hurting Avista's customer service reputation.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

- The business case justification narrative for ER 3006 will need to be updated to reflect larger budget needs in future years, as well as the need to extend the program beyond 2024. Currently the program is scheduled to end at the end of 2024, but there are at least four additional major gas overbuild projects similar to 301 Freeman Rd that need to be remediated.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Jeff Webb	BC Owner	Jeff Webb	10/12/23
Alicia Gibbs	BC Sponsor	Alicia Gibbs	10/12/2023
	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

ER 3055 – Gas PMC Program

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2022), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The PMC Program is necessary to comply with public utility commission rules and tariffs in Oregon, Washington and Idaho, which requires Avista to test meters for accuracy and ensure proper metering performance. This business case addresses change-out of both test sample meters and Failed Family meters. Failed Family meters are removed from the field because testing and analysis indicates the meter family (manufacturer year and model/size) is not metering accurately.

The planned transfer to plant is $3,799,993. The actual transfer to plant is $1,494,316.

In 2022, national supply chain issues had a significant negative impact on Avista's ability to procure necessary meter supply. These unforeseen supply chain issues came at a time when Avista's meter inventory was low, which compounded the challenges. On this basis, the Failed Family Program was temporarily paused for 2022 and 2023 with the goal of preserving existing meter inventory for new customers and for damaged meter/high bill meter replacements. The program is expected to resume in 2024.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Capital spending levels are reviewed monthly. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, gas leadership agrees on submitting funds requests or releases, if necessary. Those funds forms are submitted to the company's Capital Planning Group (CPG) for funding consideration. Approved Business Case Funds Request(s) are included with this form.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets for this period.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Jeffrey A Webb

DIRECTOR SIGNATURE:

X Alicia Gibbs

Gas PMC Program, ER 3055

EXECUTIVE SUMMARY

Avista is required by state commission rules and tariffs in WA, ID, and OR to annually test gas meters for accuracy and ensure proper metering performance. Execution of this program on an annual basis ensures the continuation of reliable and accurate gas measurement for our customers and compliance with the applicable state tariffs. Customers benefit from this program because it ensures that they are not overpaying for gas consumption if their meter's accuracy is out of specification. In some situations, a customers' meter could measure higher energy usage than the customer is actually using, resulting in the customers' bill being too high. Avista also benefits from this program because it helps identify slow meter families, which are meters that are registering under 100% accuracy. In these situations, the meter is undermeasuring the energy that is being used by the customer; therefore, the customer is being billed for less energy than they are actually using

The Planned Meter Change-out (PMC) Program uses a statistical sampling methodology based on ANSI Z1.9 "Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming". Sample sizes and acceptance criteria are defined in the ANSI standard. The annual test results of gas meters that have been removed from the field are analyzed and a determination of the accuracy of each meter family is made. If the analytics determine a meter family, defined as a manufacturer year and model/size, is no longer metering accurately enough to meet the tariff, then that entire meter family will be replaced. Conversely, if the analytics determine a meter family is testing well, the sample size can be reduced. The sample size is defined as the number of meters in that family required to be tested. These analytics help control costs and remove meters quickly that are not performing well.

This testing and replacement approach controls the cost of the program to provide the best value for customers compared to other meter replacement strategies, for example replacing meters after a prescribed number of years. Statistical analysis has proven that older meter families can retain their accuracy and perform like a new meter; therefore, there is no benefit to customers to replace older meters that are performing within the accuracy specifications.

The program also provides Avista with the statistical data necessary to identify drifts in meter accuracy. If a meter family shows a consistent drift in mean accuracy, the meter reading may be corrected by adjusting the entire family's Installation Constant value in the Meter Data Management system, rather than removing the meters from service. This approach allows Avista to adjust and leave meters in service that would have otherwise needed to be replaced, while still accurately billing customers.

This program includes only the labor and minor materials associated with the PMC Program. Major materials (meters, pressure regulators, and Encoder Receiver Transmitter (ERT)) will be charged to the appropriate Gas Growth Programs. The annual cost for the program varies depending on the results of the previous year's statistical analysis. On average, approximately 6,000 meters are removed annually for this program resulting in an average cost of $1,500,000 ($250/meter).

Avista would not be in compliance with state commission rules and tariffs in WA, ID, and OR if this program is not completed annually. This would put Avista at risk of receiving a public violation, which would result in the erosion of public trust and potential fines. State fines are not prescribed and it is up to each state to determine the fine amount.

Gas PMC Program, ER 3055

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/16/2017*
1.1	*Jeff Webb*		*4/07/2017*
2.0	*Dave Smith*	*Revised for 2020 Oregon GRC Filing*	*2/17/2020*
2.1	*Dave Smith*	*Updated to the refreshed 2020 Business Case Template*	*6/24/2020*
2.2	*Dave Smith*	*Updated to the refreshed 2022 Business Case Template*	*5/05/2022*
2.3	*Shontelle Wilson*	*Updated to the refreshed 2023 Business Case Template*	*3/20/2023*
2.4	*Dave Smith*	*Updated per BCRT Feedback*	*3/29/2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/27/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**2,800,000**	**2,800,000**
2025	**3,600,000**	**3,600,000**
2026	**3,000,000**	**3,000,000**
2027	**2,600,000**	**2,600,000**
2028	**1,700,000**	**1,700,000**

Project Life Span	***Ongoing***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Dave Smith / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Gas PMC Program, ER 3055

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Avista is required by state commission rules and tariffs in WA, ID, and OR to test meters for accuracy and ensure proper metering performance. Execution of this program on an annual basis ensures the continuation of reliable gas measurement and compliance with the applicable tariffs. If Avista does not complete this annual program we will be out of compliance with state rules and tariffs which could result in a violation (which is made public) and erosion of public trust.

1.2 Discuss the major drivers of the business case.

This program is a mandatory requirement to be in compliance with state commission rules and tariffs in WA, ID, and OR.

The following state rules regulate Avista's PMC Program:

Oregon:

- OAC 860-023-0015 "Testing Gas and Electric Meters"
- Tariff Rule #18

Idaho:

- IDAPA 31.31.01.151 through .157 "Standards for Service"

Washington:

- WAC Chapter 480-90-333 through -348 "Gas companies – Operations"
- Tariff Rule #170

Being out of compliance with these rules and tariffs could result in a violation and potential fines. State fines are not prescribed and it is up to each state to determine the fine amount.

Our customers benefit from this program because it assures that natural gas consumption is measured accurately in all jurisdictions. Accurate measurement ensures accurate customer billing.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Avista would not be in compliance with state commission rules and tariffs in WA, ID, and OR if this program is not completed annually. Also, the accuracy of measurement of our customers' natural gas usage could not be assured. See below for breakdown of these risks:

Gas PMC Program, ER 3055

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines*	H	H	VH	VH	VH	$257,664 per day per violation (Max) $2,576,627 Total (Max)
2	Pipeline Leak	Not Applicable					Not Applicable
3	Pipeline Failure & Outage	Not Applicable					Not Applicable
4	Negative Reputation	H	H	VH	VH	VH	Erosion of PUC and Public trust
5	Employee & Public Safety	Not Applicable					Not Applicable

*State fines are not prescribed and it is up to each state to determine the fine amount. Federal regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e., failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties (actual penalty amount is at the discretion of the state or federal agency).

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's Strategic Goals of Reliability and Trustworthiness for our customers. When meter accuracy is outside of the 2% tolerance customers may be overcharged. This would cause customer dissatisfaction and could hurt the reputation of Avista. "Our word is reliable; we do what is right." The PMC Program aligns with Avista's focus on giving customers a high quality of service.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

- Gas PMC Program Standard Operating Procedure
  - This procedure covers the methodology, testing requirements, and annual reporting guidelines for Avista's gas meter measurement performance testing program (PMC Program) for new and in-service meters.
- ANZI Z1.9 "Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming"
  - This is the methodology for sample sizes and analysis for the meter testing program.
- The following state rules and tariffs require Avista to administer a meter sampling program:

Oregon:

- OAC 860-023-0015 "Testing Gas and Electric Meters"
- Tariff Rule #18

Idaho:

- IDAPA 31.31.01.151 through .157 "Standards for Service"

Washington:

- WAC Chapter 480-90-333 through -348 "Gas companies – Operations"
- Tariff Rule #170

These documents are saved on the Avista network drive c01d44 and can be made available upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The program is completed between January and December of each year. Gas Engineering, Gas Operations, Gas Meter Shop, and Technical Services work together to administer the PMC program. Gas Operations and the Gas Meter Shop personnel remove the meters from the customer's premise and install new ones. If a large meter family fails, Avista may hire a contractor to assist in the removal of the meters. The Gas Meter Shop completes physical calibration tests on the meters and the Technical Services group then analyzes the test results at the end of the year to determine the status of each family of gas meters. The results of this analysis will define the meter removal and testing requirements for the following year. Gas Engineering develops an annual report which is made available to the state commissions upon request.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

The program also provides Avista with the statistical data necessary to identify drifts in meter accuracy. If a meter family shows a consistent drift in mean accuracy, the meter reading may be corrected by adjusting the entire family's Installation Constant value in the Meter Data Management system rather than removing the meters from service.

Execution of this program on an annual basis ensures the continuation of reliable gas measurement and compliance with the applicable tariffs, which is state mandatory in WA, ID, and OR. The recommended solution is to complete this mandatory programmatic work. Completion of this program will keep Avista in compliance with state rules and tariffs and assure that our customers' natural gas use is measured accurately. Partial completion of this program will result in Avista being out of compliance with state rules and tariffs.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The PMC Program uses a statistical sampling methodology based on ANSI Z1.9 "Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming". Sample sizes and acceptance criteria are defined in the ANSI standard. The annual test results of gas meters that have been removed from the field are analyzed and a determination of the accuracy of each meter family is made. If the analytics determine a meter family (defined as a manufacturer year and model/size) is no longer metering accurately enough to meet the tariff, then that entire meter family will be replaced. Conversely, if the analytics determine a meter family is testing within tolerance (close to 100% accurate), the sample size (number of meters in that family required to be tested) can be reduced. These analytics help control costs and remove meters quickly that are not performing well.

The meter accuracy testing results collected annually from the program are documented and analyzed in an Excel spreadsheet. This spreadsheet performs calculations based on ANSI Z1.9 to determine the following year's sampling requirements and identify which meter families do not meet the accuracy standards and must be removed. This analysis also checks that the Installation Constant value assigned to meters that have a consistent drift in mean accuracy are measuring within the specified accuracy range, and the Installation Constant value adjusted as necessary. All results are saved and then presented on the annual Gas Meter Measurement Performance Report. This can be made available upon request.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M		$0	$0	$0	$0	$0

No direct offsets could be identified for this program.

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Avoid Meter Replacements by Adjusting the Installation Constant	$5.2MM	$5.3MM	$5.5MM	$5.7MM	$0*
O&M		$0	$0	$0	$0	$0

*Per the PMC Program Standard Operating Procedure failed family replacement timelines, 25% of the total 87,000 meters would need to be replaced each year starting in 2024 and ending in 2027.

Completing the annual PMC Program provides indirect savings. The program provides Avista with the statistical data necessary to identify drifts in meter accuracy. If a meter family shows a consistent drift in mean accuracy, the meter reading may be corrected by adjusting the entire family's Installation Constant value in the Meter Data Management system rather than removing the meters from service. This approach has allowed Avista to adjust and leave approximately 86,000 meters in service that would have otherwise needed to be replaced. See the file titled *ER 3055 PMC Program Offset Calculations 2023.xlsx* showing the calculations for the indirect savings.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

The only alternatives are to either partially fund this program or to not fund it at all. If this program was not completed fully, Avista would be out of compliance with state rules and tariffs and could be exposed to fines from the various state utility commissions. There are

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[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

not prescribed fine ranges for state violations and it is up to state staff to determine the amount of any fines. Also, the accuracy of measurement of our customers' natural gas usage could not be assured.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

All of the meters in the random sampling program will be identified by a "flag" in Avista's Service Suite mobile application at the beginning of a calendar year. Meters shall be chosen at random and in sufficient quantities to meet the guidelines for sampling as detailed in the standard. Once the required number of meters in each family is removed for testing the "flag" will be removed in Service Suite indicating that no more meters in that family are required for testing.

Meters identified as a failed family meter will have a Maximo work order created to remove them from service. These work orders are used to track progress throughout the year.

A weekly Cognos report named *MR-130121 Gas PMC FF Meters Pulled and Tested.xlsx is* generated and sent to the program manager in Gas Engineering. This report summarizes the status of the random sampling program and the removal of the failed family meters. This report is used to track the progress of the program throughout the year. The image below shows the weekly report:

- Red rows indicate failed family meters.
- White rows indicate meter families in the random sampling program that have not had the minimum number of meters pulled for the year.
- Green rows indicate meter families in the random sampling program that have had the minimum number of meters pulled for the year.

AVISTA

PMC/FF Weekly Summary Meters Pulled

Data Source Maximo

Data Updated Daily

Gas Meters Pulled by Meter Family for Current Year

*****Test Families will display when at least 1 Meter is Pulled *****

Sampling Group-Asset	MFG Year	Model #	Sampling Template Final	Meters Pulled	Remaining Meters	% Complete - Meters Pulled
5B_1959	1959	5B	858	10	848	1.17%
5B_1960	1960	5B	50	11	39	22.00%
5B_1961	1961	5B	50	6	44	12.00%
5B_1962	1962	5B	7	7	0	100.00%
5B_1963	1963	5B	35	17	18	48.57%
AC250_1980	1980	AC250	50	9	41	18.00%
AC250_1983	1983	AC250	7	7	0	100.00%
AC250_1984	1984	AC250	7	7	0	100.00%
AC250_1985	1985	AC250	35	7	28	20.00%

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is an annual program that needs to be completed every year to maintain compliance with WA, ID, and OR state commission rules and tariffs. The Gas Meters are purchased under ER 1050.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Gas Engineering, Gas Operations, Gas Meter Shop, and Technical Services work together to administer the PMC Program and ensure compliance with the various state rules and tariffs related to gas meter testing. Gas Engineering is responsible for developing the annual Gas Meter Measurement Performance Report which defines future work under the program. Gas Engineering then determines the annual budget requirements based on the number of meters that need to be removed to satisfy the program requirements.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas PMC Program, ER 3055* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeffrey A Webb	Date:	4/25/23
Print Name:	Dave Smith / Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		
Signature:	Alicia Gibbs	Date:	4/25/2023
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Gas PMC Program, ER3055

1.0 CHANGE REQUEST #1 – 3/14/23

Previous Requests	Requested	Approved
5-Year Plan	$0	$0

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
3-2023	$146,967	$0	+$603,033	$750,000

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	4/26/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

Due to limited meter inventory and supply chain shortages, the 2022 and 2023 PMC and Failed Family program has been put on hold. Due to this situation the budget for this program was set to $0 for 2023, however this did not consider meter replacements for reasons other than the PMC and Failed Family program. There will continue to be meter replacements throughout the year for other reasons (examples: noisy meter, damaged meter, bill investigations, etc.). The year-to-date spend as of March 14th is $146,967. This trend is expected to continue throughout the year, which will result in an estimated spend of approximately $750,000 by the end of the year.

It is also possible that Avista will take delivery of adequate meter inventory later in the year which will require the PMC Program to resume. If this happens, more funds will be needed to start up the PMC and Failed Family program. Another Funds Request will be submitted at that time if necessary.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

This work is needed to ensure reliable and accurate metering for gas customers.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

N/A. These necessary meter replacements due to the reasons listed above are needed to ensure reliable and accurate metering.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

These meter replacements will be performed by gas servicemen using existing processes.

Gas PMC Program, ER3055

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The alternative would be to not replace any meters regardless of if they are noisy, broken, or have other issues. This alternative is not recommended because it may result in metering issues and unhappy customers.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

These necessary meter replacements due to the reasons listed above are needed to ensure reliable and accurate metering, and to maintain customer satisfaction.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

- Narrative is still valid.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
David Smith / Jeff Webb	BC Owner	Jeffry a Webb	4/18/23
Alicia Gibbs	BC Sponsor	Alicia Gibbs	4/18/23
	FP&A		

Gas PMC Program, ER3055

1.0 CHANGE REQUEST #2 – 8/29/23

Previous Requests	Requested	Approved
3-2023	$603,033	$603,033

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
8-2023	$650,000	$750,000	+$677,000	$1,427,000

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	10/1/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

Due to limited meter inventory and supply chain shortages, the PMC and Failed Family program was temporarily paused in 2022. Since the pause, meter replacements have been limited to reasons other than PMC and Failed Family, for example a noisy meter, customer requested bill investigation, damaged meters, etc. Meter inventory for most meter sizes has now been replenished enough to partially resume the PMC and Failed Family meter program. Below are the estimated quantity of meters we expect to replace by the end of 2023:

PMC:

110 meters

Failed Family:

2,780 meters

Total = 2,890 meters

The estimated cost to replace each meter is estimated at $234 (based on historical program spend and adjusted for wage increases).

Estimated additional funds needed = $234 per meter x 2,890 meters = $676,260

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

Avista is required to perform this program work per our natural gas tariffs. Avista filed for a waiver to temporarily pause this program from the three state commissions due to meter inventory shortages. Washington and Idaho approved the waiver to temporarily postpone with the understanding that work would commence when meter inventory was replenished. Oregon has yet to approve the waiver. It is prudent to resume this program now that we have adequate meter inventory to support the work in most meter sizes.

Gas PMC Program, ER3055

1.1.3 Please reference analysis or information that support the problem and attach to this document.

The 2021 PMC report summarizes the required quantity of PMC and Failed Family meters that require replacement. Please note that there is not enough meter inventory to support the program in its entirety, therefore only a portion of the meter will be replaced in 2023 as quantified in section 1.1.1 above.

2021 PMC Report.pdf

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

These meter replacements will be performed by gas servicemen using existing processes.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The alternative would be to continue to pause the PMC and Failed Family program even though we have enough meter inventory to resume. Doing this would violate the conditions of the waiver request to temporarily pause the program which states that Avista will resume the program when adequate meter inventory is established.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

This annual program is required by the natural gas tariffs in Washington, Idaho, and Oregon.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

- Narrative is still valid.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
David Smith / Jeff Webb	BC Owner	[illegible]	8/29/23
Alicia Gibbs	BC Sponsor	Alicia Gibbs	8-2023
	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

ER 3002 - Gas Regulator Station Reliability

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This annual program will replace or upgrade existing at-risk Gate Stations, Regulator Stations, Single Service Farm Taps, and Industrial Meter Sets located throughout Avista's gas territory in WA, ID, and OR that are at the end of their service life and/or not up to current Avista standards. Additionally, it will address enhancements that will improve system operating performance, enhance public and employee safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment.

The Gas Regulator Station Reliability program's transfer to plant amount in 2023 shows a significant variance (+$742,780) compared to the program's budget ($1,000,000); however, the program did not spend more than the budgeted amount in 2023. The large TTP variance is due to several projects that were started in 2022 and went in to service in 2023. In the first 5 months of 2023, there was approximately $700k transferred to plant. That is a much higher amount than for that same time period during a typical year. The program's actual spending is within +/-10% of the budgeted amount.

The planned transfer to plant was $1,000,002. The actual transfer to plant was $1,742,782.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The Gas Regulator Station Reliability program did not have overruns in actual spending on the 2023 budget. Capital spending levels are reviewed monthly. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, gas leadership agrees on submitting funds requests or releases, if necessary. Those funds forms are submitted to the company's Capital Planning Group (CPG) for funding consideration.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets for this period.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Jeffrey A Webb

DIRECTOR SIGNATURE:

X Alicia Gibbs

Gas Regulator Station Replacement Program, ER 3002

EXECUTIVE SUMMARY

This annual program will replace or upgrade existing at-risk Gate Stations, Regulator Stations, Single Service Farm Taps, and Industrial Meter Sets (“stations”) located throughout Avista’s gas territory in WA, ID, and OR that are at the end of their service life and/or not up to current Avista standards. Additionally, it will address enhancements that will improve system operating performance (such as increasing the capacity of stations to meet our growing system demands), enhance public and employee safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment.

Proper functioning of these stations is required to ensure safe, reliable delivery of natural gas to all Avista customers. All stations require maintenance per 49 CFR 192.739. If the equipment at the station is obsolete and replacement/maintenance parts are no longer available, then proper maintenance cannot be completed. Incomplete maintenance could cause Avista to be out of compliance. When Avista is out of compliance, we are exposed to fines from multiple state utility commissions: Washington, Idaho, and Oregon[1].

Public and employee safety is another common driver for these upgrade projects. Many stations that are upgraded are also moved to a safer location. For example: further from the roadway where they are less likely to be hit by a vehicle and where Avista employees can have a safe parking area to access the station for maintenance. Many old stations do not have a parking space, resulting in Avista employees parking on the shoulder of the road to access the station. This puts the employee and the traveling public at greater risk of an accident.

Avista’s gas customers from all jurisdictions benefit from these types of projects by having a safer, more reliable, well maintained distribution system. Performing these upgrades is a prudent way to spend resources because many deficiencies at a station can be remedied under just one project, and proactive replacements cost less than reactive replacements.

There is already a backlog of stations needing replacement; therefore, this work is needed now. The list of stations needing replacement continues to expand as stations meet the end of their service life. Postponing this replacement program will cause the list of stations needing replacement to outpace the number of stations remediated.

Annual cost to fund this program has historically been approximately $1,000,000. The cost to rebuild a station varies greatly from project to project based on a number of factors, some of which include the type of station, size of station components, location,

[1] State fines are not prescribed and it is up to each state to determine the fine amount. Federal regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223.

and crew resources (company crews or contractor crews). Below are estimated average costs to rebuild each type of station based on historical projects:

Gate Station:	$300,000
District Regulator Station:	$100,000
Industrial Meter Set:	$ 50,000
Single Service Farm Tap:	$ 5,000

Proactive replacement of these stations is much more cost effective than reactive replacement. A recent station replacement that was completed as an emergency response to a station that was damaged by a vehicle cost approximately five times more than a planned replacement project. In addition, proactive replacement is preferred due to material availability. Long lead-times on materials necessary for these rebuild projects may mean that if stations run to failure, we may not have the materials necessary for replacement.

Updated stations are also typically easier to maintain than older designs; therefore, future maintenance costs are reduced. On average, a new station takes about 1 hour less to maintain than an obsolete station, which is a direct O&M savings. These O&M savings compound each year as more stations are rebuilt. Over 40 years, the average lifespan of a station, these O&M savings are estimated to be $3,250,000.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/17/2017*
1.1	*Jeff Webb*		*4/07/2017*
2.0	*Jeff Webb*	*Revised for 2020 Oregon GRC filing*	*2/17/2020*
2.1	*Dave Smith*	*Updated to the refreshed 2020 Business Case Template*	*6/24/2020*
2.2	*Dave Smith*	*Updated to the refreshed 2022 Business Case Template*	*5/5/2022*
2.3	*Shontelle Wilson*	*Updated to the refreshed 2023 Business Case Template*	*3/9/2023*
2.4	*Dave Smith*	*Updated per BCRT Feedback*	*3/31/2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	*4/3/2023*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**1,070,000**	**1,070,000**
2025	**1,070,000**	**1,070,000**
2026	**1,070,000**	**1,070,000**
2027	**1,070,000**	**1,070,000**
2028	**1,070,000**	**1,070,000**

Gas Regulator Station Replacement Program, ER 3002

Project Life Span	***Ongoing***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Dave Smith / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Existing stations located throughout Avista's gas territory in WA, ID, and OR have a finite service life. If they are not periodically replaced and updated, the stations will eventually no longer meet Avista's current design standards, the equipment may become obsolete, or the stations may develop operational or safety issues that need to be addressed to deliver safe and reliable gas service to customers.

Public and employee safety is another common driver for these upgrade projects. Many stations that are upgraded are also moved to a safer location. For example: further from the roadway where they are less likely to be hit by a vehicle and where Avista employees can have a safe parking area to access the station for maintenance. Many old stations do not have a parking space resulting in Avista employees parking on the shoulder of the road to access the station for maintenance. This puts the employee and the traveling public at greater risk of an accident.

Gas Engineering maintains a Station Evaluation Spreadsheet that summarizes the condition of each station. This spreadsheet is used to help identify which stations are the highest risk and assists in prioritizing the work under this program. Below is a partial screen shot example from that list.

Station	Year Assessed	Score	Station Ty	Location	Paint	Corrosi	Welds Pass Visi	Threaded Fitting	Bypass	Sense Line Configurati	Height	Pipe Settli	Supports	External Forc	Pressu
232	2020	56	GS		Good	None	No	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Too Short	None	Yes, Non-Adjust	Major	Adequ
22	2021	55.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	Hard	Short	Requires ladder/platform	None	Not Needed	None	Adequ
13	2021	54.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	None	Short	Adequate	None	Not Needed	None	Blank
278	2020	54	DR		Cracking/Flaking	None	Blank	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Adequate	None	Not Needed	Minor	Not Ad
28	2021	51.5	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires ladder/platform	None	Not Needed	None	Adequ
36	2021	49	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires Ladder/Platform	None	Not Needed	None	Blank
~~31~~	~~2021~~	~~48~~	~~DR~~		~~Cracking/Flaking~~	~~None~~	~~No~~	~~No~~	~~Hard~~	~~short~~	~~Too Short~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
33	2021	47	DR		Cracking/Flaking	None	No	No	Hard	Short	Adequate	None	Not Needed	None	Adequ
~~27~~	~~2021~~	~~45.5~~	~~DR~~		~~Cracking/Flaking~~	~~Minor~~	~~No~~	~~No~~	~~Lead/Lag~~	~~short~~	~~Requires Ladder/Platform~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
34	2021	45	DR		Cracking/Flaking	Minor	No	No	Hard	short	Requires Ladder/Platform	None	Not Needed	None	Adequ
1343	2021	44.5	SSFT	5509 W Lawton	Cracking/Flaking	Significant	Blank	yes on HP, yes on IP	Soft	Blank	Adequate	None	Not Needed	None	Adequ
26N05	2020	43	GS		Good	None	Blank	Yes on HP, Yes on IP	None	Blank	Too Short	None	Blank	None	Not Ad

Gas Regulator Station Replacement Program, ER 3002

1.2 Discuss the major drivers of the business case.

This program's primary driver is asset condition. By proactively replacing obsolete stations, we will continue to deliver safe and reliable gas service to customers. On average, a typical station has a useful life of approximately 40 years[2]. This is because when equipment is antiquated, parts are no longer readily available causing station reliability to be diminished. Obsolete stations are often more difficult and take longer to maintain, which increases O&M costs to the company. On average, an obsolete station takes approximately 1 hour longer to maintain than a new station. This additional 1 hour of labor is entirely O&M. See section 2.2 for O&M savings calculations.

Public and employee safety is another common driver for these upgrade projects. Many stations that are upgraded are also moved to a safer location. For example: further from the roadway where they are less likely to be hit by a vehicle and where Avista employees can have a safe parking area to access the station for maintenance. Many old stations do not have a parking space resulting in Avista employees parking on the shoulder of the road to access the station. This puts the employee and the traveling public at greater risk of an accident. In a severe case, vehicle damage to a station may cause a customer outage. It is hard to predict the severity of the outage because the number of customers downstream of each station varies greatly across the system.

The cost of an outage is estimated at $2,960 per customer[3]. This cost includes the cost for Avista to restore service and the potential economic impacts to the customer. The calculation assumes that restoration will be completed within 24 hours, which is Avista's restoration goal. A severely damaged station may take longer than 24 hours to repair and bring back into service.

Below are potential outage costs for varying degrees of customer outages:

Number of Customers Out of Service	Potential Cost
1	$2,960
10	$29,960
100	$296,000
1,000	$2,960,000

[2] The average life of a typical station was estimated by looking at the age of historical stations that were rebuilt under this program

[3] The Interruption Cost Estimate (ICE) Calculator was used to estimate the economic impacts to the customer at $116 per hour per customer. An estimated restoration cost of $176 per customer is based on the actual restoration costs incurred during the 2022 Crestline outage in Spokane. Therefore the total cost per customer is estimated to be $116 x 24 hours + $176 = $2,960.

Gas Regulator Station Replacement Program, ER 3002

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed now because there is already a backlog of stations needing replacement. The list of stations needing replacement continues to grow as stations meet the end of their service life. Postponing the work will cause the list of stations needing replacement to outpace the number of stations remediated. When this happens, there becomes a greater risk to having equipment fail due to outdated/unsafe conditions or an employee or public safety incident.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time (years)					Cost Estimate
		1	2	5	10	15+	
1	Regulatory Fines*	L	L	L	L	L	$257,664 per day per violation (Max) $2,576,627 Total (Max)
2	Pipeline Leak	L	P	P	H	VH	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	L	L	P	P	H	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	L	L	L	P	P	Erosion of PUC and Public trust
5	Employee & Public Safety	L	P	P	H	H	Lost time, lawsuits, healthcare , etc. (varies)

*State fines are not prescribed, and it is up to each state to determine the fine amount. Federal regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e., failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties (actual penalty amount is at the discretion of the state or federal agency).

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Mission Statement excerpt: "By delivering energy safely, responsibly, and affordably, Avista helps empower our customers to live their lives to the fullest." By proactively replacing obsolete or unsafe stations, we continue to provide safe, reliable service for our customers and ensure that customers will not experience an unplanned interruption of gas service.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[4]

The Gate Station, District Regulator Station, SSFT, and Industrial MSA Evaluation Form is filled out by Gas Operations who perform station maintenance. This form helps to risk rank each station based on many criteria including station condition, equipment, location and access, and inlet and outlet valves. The data from these forms is consolidated into a master spreadsheet which then calculates a score for each station. The higher the score, the higher priority the station is for replacement. Below is what the Evaluation Form looks like.

AVISTA

Gate Station, District Regulator Station, SSFT, and Industrial MSA Evaluation Form

Station #__________ Station Type:____________ Location:______________________

Overall Station Condition

Paint	☐Good	☐ Cracking/Flaking			
Corrosion	☐None	☐Minor	☐Significant (provide comment below)		
Welds Pass Visual Inspection		☐Yes ☐No			
Threaded Fittings	☐Yes on HP	☐Yes on IP	☐No		
Bypass	☐Full ☐Partial ☐Lead/Lag ☐Hard ☐Soft ☐None ☐Single Valve Isolation				
Sense Line Conf.	☐Standard	☐Short	☐Underground		
Height	☐Adequate	☐Requires Ladder/Platform ☐Too Short			
Pipe Settling	☐Major	☐Minor	☐None		
Supports	☐Yes, Adjust☐Yes, Non-Adjust ☐Not Needed ☐No but Needed				
External Forces	☐Major (provide comment below)	☐Minor	☐None		
Pressure Ports	☐Adequate	☐Not Adequate (provide comment below)			
Ability to Check Lockup	☐Yes	☐No			

Comments:

Station Equipment

Regulator(s)	☐Standard	☐Non-Std	☐Obsolete	☐Flanged	☐Threaded
Relief Valve(s)	☐Standard	☐Non-Std	☐Obsolete	☐N/A	
Strainer/Filter(s)	☐Standard	☐Non-Std	☐Obsolete	☐None	
Valve(s)	☐Standard	☐Non-Std	☐Obsolete	☐Non-Operable	
Greasable Valve Upstream of Reg		☐Yes ☐No			
Odorizer	☐Adequate	☐Not Adequate (provide comment below) ☐N/A			
Heater	☐Adequate	☐Not Adequate (provide comment below) ☐N/A			

Comments:

Facility Access, Location, and Protection

Fence	☐Good ☐Minor Issues☐Severe Issues ☐Vandalism ☐N/A			
Building	☐Good ☐Minor Issues☐Severe Issues ☐Vandalism ☐N/A			
Barricade	☐Sufficient	☐Not Sufficient	☐Doesn't Need	
Access	☐Drive-up	☐Walk-up	☐Un-Safe (provide comment below)	
Location	☐Good ☐Poor (provide comment below) ☐Easement ☐Right-of-Way			
Parking	☐ Parking Space	☐On Street/Shoulder	☐None	
Overhead Power	☐Yes	☐No		
Vault	☐Yes	☐No		
Venting	☐Sufficient	☐ Needs Venting	☐N/A	

Comments:

Inlet and Outlet Valves

Inlet Valve(s)	☐20'-50' Away ☐<20' ☐>50' ☐Inside Fence ☐No Valve
Outlet Valve(s)	☐20'-50' Away ☐<20' ☐>50' ☐Inside Fence ☐No Valve

Comments:

[4] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Gas Regulator Station Replacement Program, ER 3002

The *Station Evaluation Spreadsheet.xlsx* is the master spreadsheet that contains the evaluation scores for each station. A partial screenshot of this spreadsheet is shown below.

Station	Year Assesse	Score	Station Ty	Location	Paint	Corrosi	Welds Pass Visi	Threaded Fittin	Bypass	Sense Line Configurati	Height	Pipe Settli	Supports	External For	Pressu
232	2020	56	GS		Good	None	No	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Too Short	None	Yes, Non-Adjust	Major	Adequ
22	2021	55.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	Hard	Short	Requires ladder/platform	None	Not Needed	None	Adequ
13	2021	54.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	None	Short	Adequate	None	Not Needed	None	Blank
278	2020	54	DR		Cracking/Flaking	None	Blank	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Adequate	None	Not Needed	Minor	Not Ad
28	2021	51.5	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires ladder/platform	None	Not Needed	None	Adequ
36	2021	49	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires Ladder/Platform	None	Not Needed	None	Blank
~~31~~	~~2021~~	~~48~~	~~DR~~		~~Cracking/Flaking~~	~~None~~	~~No~~	~~No~~	~~Hard~~	~~short~~	~~Too Short~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
33	2021	47	DR		Cracking/Flaking	None	No	No	Hard	Short	Adequate	None	Not Needed	None	Adequ
~~27~~	~~2021~~	~~45.5~~	~~DR~~		~~Cracking/Flaking~~	~~Minor~~	~~No~~	~~No~~	~~Lead/Lag~~	~~short~~	~~Requires Ladder/Platform~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
34	2021	45	DR		Cracking/Flaking	Minor	No	No	Hard	short	Requires Ladder/Platform	None	Not Needed	None	Adequ
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26N05	2020	43	GS		Good	None	Blank	Yes on HP, Yes on IP	None	Blank	Too Short	None	Blank	None	Not Ad

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The requested level of spending for this program allows the high priority projects to be completed every year. The list of new requests continues to grow as stations meet the end of their service life. The workforce available to do this type of work is responsible for both maintenance of these stations and the rebuild efforts. This level of spend complements their available time as well, without requiring additional labor resources.

This program is meant to be proactive (preventive) rather than reactive. These stations are vital to providing customers with reliable gas service. Planned replacement work is preferred over unplanned work. With proactive work, a plan can be put into place to ensure that customers do not lose gas service while the project is being completed. Reactive replacement work during times of high gas use can be more difficult to perform, have negative impacts to customers, and can inadvertently cost the company more money in resources spent than the preventive measures would. Also, due to worldwide supply chain issues, some of the equipment at these stations have very long lead times; therefore, taking a proactive replacement approach helps maintain reliable service.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[5]

Proactively replacing a station is much more cost effective than reactively replacing one that has failed or was damaged by outside forces. To illustrate,

[5] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

regulator station #66 located at the intersection of Regal St and Gordon Ave in Spokane was hit by a car in 2018. The incident happened after normal business hours and required an emergency response by Avista. This station is a typical farm tap style station. The station needed to be replaced due to extensive damage caused by the vehicle, and the cost to replace the station was approximately five times higher than what it would have cost to replace the station under a planned project. The major contributor to the cost being so much higher is crew overtime, as these emergency events must be worked until made safe and service restored. The cost to replace the damaged station was approximately $15,000 whereas the cost to proactively replace the station would have been approximately $3,000.

Emergency repair or replacements can also increase the risk of a customer outage versus a planned replacement project. Public and employee safety is of utmost importance during a gas emergency, therefore under most circumstances quickly isolating the affected system takes priority over maintaining service to customers. If a station failed or was damaged by an outside force resulting in a gas leak or a system abnormal operating condition, it is likely that first responders will isolate the system which may result in customer outages. During planned worked there are measures taken to maintain gas service to customers, for example installing a bypass around the work zone. These measures to maintain service to downstream customers take additional time to install in the field and therefore may not be appropriate or available during a gas emergency.

Another risk associated with running a station to failure is equipment and material availability. Many stations have long lead time equipment and materials that may not be available when needed. If equipment or materials are not available, temporary equipment or materials may have to be installed in order to resore service to customers. These temporary items may have to be replaced with the appropriate permanent items at a later date, further increasing costs associated with the event.

2.3 Summarize in the table and describe below the DIRECT offsets[6] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M	Reduced Station Maintenance Time	$3,400	$5,300	$7,200	$9,300	$11,500

[6] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

Gas Engineering, Gas Operations, and the Gas Meter Shop work together to prioritize and administer the work for the year. The work is generally prioritized early in the year and then implemented throughout the spring, summer, and fall. The work is typically comprised of several individual station replacement projects.

Completion of this work will reduce O&M costs because stations that are at the end of the end of their service life and/or are not up to Avista's current standards typically take longer to maintain. Refer to spreadsheet titled *Offset Calcs ER 3002.xlsx showing* the calculations for the direct savings shown in the table above.

2.4 Summarize in the table and describe below the INDIRECT offsets[7] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M	Outage Avoidance	$76,960	$76,960	$76,960	$76,960	$76,960

Completing this annual program will reduce the potential for a customer outage due to equipment failure or a physically damaged station. The estimated cost of an outage is estimated at $2,960 per customer[8]. This cost includes the cost for Avista to restore service and the potential economic impacts to the customer. The calculation assumes that restoration will be completed within 24 hours, which is Avista's restoration goal. A severely damaged station may take longer than 24 hours to repair and bring back into service.

Below are the potential restoration and customer economic costs for varying numbers of customer outages:

Number of Customers Out of Service	Potential Cost	Likelihood of Event
1	$2,960	1
10	$29,960	0.5
100	$296,000	0.1
1,000	$2,960,000	.01

[7] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

[8] The Interruption Cost Estimate (ICE) Calculator was used to estimate the economic impacts to the customer at $116 per hour per customer. An estimated restoration cost of $176 per customer is based on the actual restoration costs incurred during the 2022 Crestline outage in Spokane. Therefore the total cost per customer is estimated to be $116 x 24 hours + $176 = $2,960.

See spreadsheet *Offset Calcs ER 3002 – Reg Reliability 2023.xlsx* for assumptions and calculations.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Option	Capital Cost	Start	Complete
Recommended Solution, Replace at risk stations at requested funding level	$1,070,000	January	December
Alternative Solution 1, Replace at risk stations at a reduced funding level	$500,000	January	December
Alternative Solution 2, Do nothing	$0		

Alternative 1:

The alternative solution would be to replace at risk stations at a reduced funding level. There is already a backlog of approximately 30 high-risk stations that need to be replaced. This approach would take longer to get through the backlog. Meanwhile, new stations are added to the list every year due to aging infrastructure. Therefore, Alternative 1 will eventually surpass the Recommended Solution in not only cost but inefficiency as well.

An alternative to rebuilding the entire station would be to replace only the individual components that are antiquated or outdated. If this short-sided course were chosen, the work would be less productive and the opportunity to bring the entire station up to current standards would be lost. Often older stations that have antiquated or outdated equipment are also difficult to maintain due to outdated configurations, for example short sensing lines, limited valve locations, and equipment being installed high above ground or in vaults. This option is not recommended. Another downside to this approach would be the loss of opportunity to right size the capacity of the rebuilt station. Often station capacity is increased when the station is rebuilt to support future demands.

Alternative 2:

If the program were to not be funded, Avista would be forced to operate at-risk stations in an unsafe, unreliable, and sometimes non-code compliant manner. The risk of not doing the work includes, but is not limited to, regulatory fines, pipeline leaks, pipeline failures and outages, negative company reputation, and employee and public safety. O&M costs would escalate as the number of

Gas Regulator Station Replacement Program, ER 3002

unplanned visits to these stations would likely increase due to operating them at or beyond their useful lives. This option is not recommended.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success can be measured through the *Station Evaluation Spreadsheet.xlsx*, which is the master spreadsheet that contains the evaluation scores for each station. A partial screenshot of this spreadsheet is shown below.

Station	Year Assesse	Score	Station Ty	Location	Paint	Corrosi	Welds Pass Visi	Threaded Fittin	Bypass	Sense Line Configurati	Height	Pipe Settli	Supports	External Forc	Pressu
232	2020	56	GS		Good	None	No	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Too Short	None	Yes, Non-Adjust	Major	Adequ
22	2021	55.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	Hard	Short	Requires ladder/platform	None	Not Needed	None	Adequ
13	2021	54.5	DR		Cracking/Flaking	Minor	No	Yes on HP, Yes on IP	None	Short	Adequate	None	Not Needed	None	Blank
278	2020	54	DR		Cracking/Flaking	None	Blank	Yes on HP, Yes on IP	Single Valve Isolation	Blank	Adequate	None	Not Needed	Minor	Not Ad
28	2021	51.5	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires ladder/platform	None	Not Needed	None	Adequ
36	2021	49	DR		Cracking/Flaking	Minor	No	No	Hard	Short	Requires Ladder/Platforn	None	Not Needed	None	Blank
~~31~~	~~2021~~	~~48~~	~~DR~~		~~Cracking/Flaking~~	~~None~~	~~No~~	~~No~~	~~Hard~~	~~short~~	~~Too Short~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
33	2021	47	DR		Cracking/Flaking	None	No	No	Hard	Short	Adequate	None	Not Needed	None	Adequ
~~27~~	~~2021~~	~~45.5~~	~~DR~~		~~Cracking/Flaking~~	~~Minor~~	~~No~~	~~No~~	~~Lead/Lag~~	~~short~~	~~Requires Ladder/Platforn~~	~~None~~	~~Not Needed~~	~~None~~	~~Adequ~~
34	2021	45	DR		Cracking/Flaking	Minor	No	No	Hard	short	Requires Ladder/Platforn	None	Not Needed	None	Adequ
1343	2021	44.5	SSFT	5509 W Lawton	Cracking/Flaking	Significant	Blank	yes on HP, yes on IP	Soft	Blank	Adequate	None	Not Needed	None	Adequ
26N05	2020	43	GS		Good	None	Blank	Yes on HP, Yes on IP	None	Blank	Too Short	None	Blank	None	Not Ad

When stations are rebuilt they will be rescored. The station's new lower score will show that the project delivered on improving reliability and reducing risk. For example, station #31 had an initial score of 48, ranking it in the top 10 stations needing to be replaced. Station #31 was replaced in 2022 and its new score is 1, placing it amongst the lowest risk stations in the system.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The program will be completed between January and December of each year. The investments become used and useful to the customer at the completion of each station rebuild project.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Gas Engineering, Gas Operations, and the Gas Meter Shop work together to prioritize and administer the work for this program. The project engineer puts together the project estimate which is then approved by the gas design manager and director. Monthly budget updates are completed in Tableau to make sure the program remains on budget throughout the year. The project engineer is also responsible to update the Station Evaluation Spreadsheet with the station's new score at the conclusion of the project.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Regulator Station Replacement Program, ER 3002* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeff a Webb	Date:	4/23/23
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	4/23/2023
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

ER 3003 - Gas Replacement Street & Hwy Program

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This Business Case is mandated by franchise agreement contracts with the city and state entities, and permits entered with railroad owners. Avista is mandated under these agreements to relocate its facilities when local jurisdictional projects necessitate. Often these projects are identified without significant lead times, which makes it difficult to forecast and estimate projects.

Actual project spend and transfer to plant can vary significantly year to year as the number and scope of municipal projects varies each year. Additionally, the impact of the municipal projects on the natural gas infrastructure varies from year to year making it challenging to forecast with a high degree of certainty. In 2023 our two largest districts, Spokane and Medford, had a significant amount work which led to the larger than expected transfer in 2023. The increases in spend were needed to complete mandated work. Not completing this work would put Avista out of compliance with respective franchise agreements.

The planned transfer to plant was $3,500,000. The actual transfer to plant was $6,457,715.

This business case was monitored through the year. In August and November, the Avista Capital Planning Group approved additional funding for the above-mentioned cost impacts.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Capital spending levels are reviewed monthly. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, gas leadership agrees on submitting funds requests or releases, if necessary. Those funds forms are submitted to the company's Capital Planning Group (CPG) for funding consideration. Approved Business Case Funds Request(s) are included with this form.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets for this period.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Jeffrey A Webb

DIRECTOR SIGNATURE:

X Alicia Gibbs

Replacement Street & Hwy Program, ER 3003

EXECUTIVE SUMMARY

Virtually all Avista’s pipeline systems are in public right-of-ways (R/W) that are governed by local jurisdictional franchise agreements. Locating Avista’s gas facilities in R/W is beneficial to customers and is common practice for other utilities as well, such as electric, water, sewer, and communications. Local jurisdictions allow Avista to install facilities in this space with no upfront payment. In situations when local jurisdictional projects create a conflict, Avista is mandated under these agreements to relocate its facilities.

When conflicts are identified that may require relocating gas facilities, meetings with the appropriate entities take place in an attempt to design around the conflict. If relocation of the gas facilities is still required after meeting, then Avista must complete the work at our cost per the applicable franchise agreement. If the conflict cannot be designed around and the gas facility must remain in service, then there are no other alternatives.

It is very difficult to forecast year-to-year what the financial impacts in this category will be in each district and state as budgets change each year for the municipalities. Some road projects are more impactful than others to the buried gas facilities. The planned spend amounts for the next five years are based on average expenditures in this budget over the last several years.

By completing the projects as requested, Avista meets the obligations under its franchise agreements, remains in good standing with the municipalities, and avoids financial penalties associated with project delays.

The work is generated by the various municipalities that Avista has franchise agreements with. Gas Operations manages this category of work in each district. The overall program budget is monitored by Gas Engineering closely throughout the year. Regular check-ins are conducted with Gas Operations to update the projected annual spend accordingly as new projects come up.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*3/17/2017*
1.1	*Jeff Webb*	*Revised*	*4/17/2017*
2.0	*Jeff Webb*	*Revised for 2020 Oregon GRC Filing*	*2/17/2020*
3.0	*Jeff Webb*	*Revised for new BC format*	*8/30/2022*
3.1	*Shontelle McGrath*	*Updated to the refreshed 2023 Business case template*	*8/2/2023*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	

Replacement Street & Hwy Program, ER 3003

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	3,718,000	3,718,000
2025	3,718,000	3,718,000
2026	3,718,000	3,718,000
2027	3,718,000	3,718,000
2028	4,063,000	4,063,000

Project Life Span	***Ongoing.***
Requesting Organization/Department	B51 / Gas Engineering
Business Case Owner | Sponsor	Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 / Gas Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The problems that are being addressed through this program are the physical conflicts between natural gas facilities and roadways or other utilities within R/W.

Virtually all Avista's pipelines are in R/W that are governed by local jurisdictional franchise agreements. Avista is mandated under these agreements to relocate our facilities, at our cost, when local jurisdictional projects necessitate. Many of these projects come to Avista without significant lead time by the local jurisdictions. It is often the case that meetings are called in the spring season to notify franchisees (natural gas, electric, cable, phone companies etc.) that they will need to relocate their facilities. This does not enable long term project planning or budget forecasts.

When conflicts are identified that may require relocating gas facilities, attempts are made to design around the conflict. If conflicts cannot be resolved, then relocation of gas facilities is required. Avista must then relocate the gas facility at our cost per the applicable franchise agreement. If the relocation project is of significant complexity, then Gas Engineering will take over the project to design and manage it through completion; otherwise, the local districts will manage the project. The business needs and potential solutions identified impact all gas customers in Avista's service territory.

1.2 Discuss the major drivers of the business case.

The major driver of the business case is Mandatory and Compliance. Per the franchise agreements with local jurisdictions, Avista is required to resolve conflicts within R/W at Avista's cost.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The nature of this work is considered "work in request of others". If the conflicts are not resolved through design changes or relocation of the gas facilities, Avista would not comply with its franchise agreements and could be charged with delay of a project. This would not only be a financial burden on the company, but it would also greatly damage the working relationship between Avista and the municipality.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

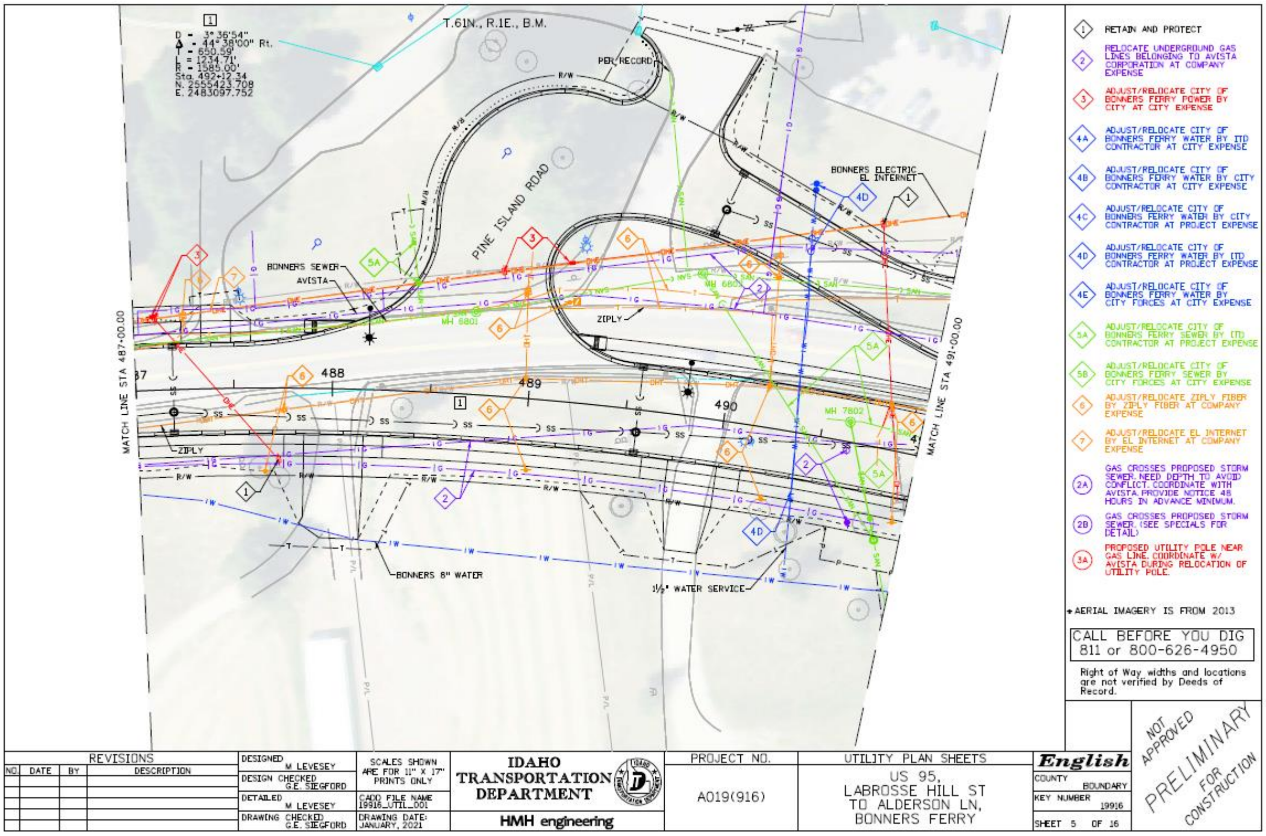
The projects within this Business Case align with Avista's values of being Trustworthy and Collaborative. We are Trustworthy when we resolve conflicts between our pipeline facilities and local jurisdictional projects since that is what Avista agreed to in the franchise agreements. We are Collaborative when we work together with local jurisdictions to either design around the conflict or come up with a relocation plan that addresses the conflict.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Here is an example of a road move project that Avista worked on with the Idaho Transportation Department in Bonners Ferry. This is just one page of the project plans that involved relocating approximately 700 feet of 2" PE main and 1,200 feet of 4" steel main that were in conflict with the new roadway design.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Replacement Street & Hwy Program, ER 3003



This is just one example of the many road move projects that are completed under this Business Case. Avista receives project plans like these from the different municipalities to aid in project relocation designs. Oftentimes, Avista representatives meet with the different municipalities in advance of the project to assist in the relocation plan.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The projects within this program address and resolve conflicts between Avista's gas facilities and projects within local jurisdictions. Each project is unique. When a jurisdiction has a project where gas facilities are in conflict, efforts are made to design around the conflict. If this is not possible, Avista works with the jurisdiction to come up with a relocation plan to eliminate the conflict.

Replacement Street & Hwy Program, ER 3003

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

By completing the projects as requested, Avista meets the obligations under its franchise agreements. A major risk associated with not completing the work under this Business Case is tarnishing Avista's good working relationships with the many municipalities in its service territory. In addition, Avista would be at risk of financial penalties associated with project delays if gas facilities in conflict were not relocated. The work done under this Business Case allows Avista to avoid these risks.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no direct offsets or savings associated with this Business Case.

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no indirect offsets or savings associated with this Business Case.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

If the conflict cannot be designed around and the gas facilities must remain in service, then there are no alternatives for the projects under this Business Case.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Projects are either managed by Gas Engineering or local CPCs. Projects are monitored by the responsible party from project initiation, through construction until the project is completed. Success can be measured by tracking completed projects and work orders under this Business Case.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Projects are typically started and completed within the same calendar year and are placed into service the same month they become used and useful.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Gas Engineering manages this Business Case. Many of the projects are handled by the local construction offices. For more complex relocation projects, Gas Engineering will manage the relocation project. Throughout the year, Gas Engineering conducts regular check-ins with the local construction offices to get updates on the road move projects for the year.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Business Case for ER3003 Replacement Street and Hwy Program and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeffrey a Webb	Date:	9/18/23
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	10/25/2023
Print Name:	Alicia Gibbs		
Title:	Director Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Gas Replace Street & Hwy Program, ER 3003

1.0 CHANGE REQUEST #1 – 8/11/2023

Previous Requests	Requested	Approved
5-Year Plan	-	-

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
8-2023	$4,131k	$3,610K	+$2,400k	$6,010k

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	8/29/2023

Gas Replace Street & Hwy Program, ER 3003

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

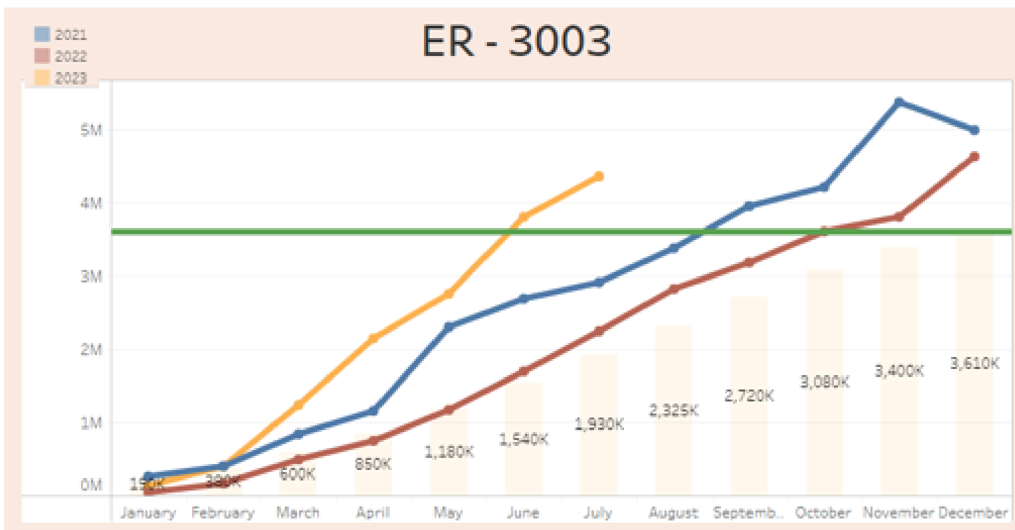
The spend rate has continued to be greater than previous years. The number and size of the projects is greater than last year, especially in Medford and Spokane.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

This is considered work in request of others.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

ER 3003 – Gas Road Moves



1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

None noted.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The projects in process can not be delayed due to obligation put upon Avista by others. No reasonable alternatives are available for this programmatic work.

Gas Replace Street & Hwy Program, ER 3003

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

This is still prudent as we need to stay in good standing with our franchise agreements.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

Confirmed, no change.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Jeff Webb	BC Owner	Jeff a Webb	8/11/22
Alicia Gibbs	BC Sponsor	Alicia Gibbs	8/14/22
	FP&A		

Gas Replace Street & Hwy Program, ER 3003

1.0 CHANGE REQUEST #2 – 11/17/2023

Previous Requests	Requested	Approved
5-Year Plan	-	-

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
11-2023	$6,307k	$6,010K	+$790k	$6,800k

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	11/30/2023

Gas Replace Street & Hwy Program, ER 3003

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE

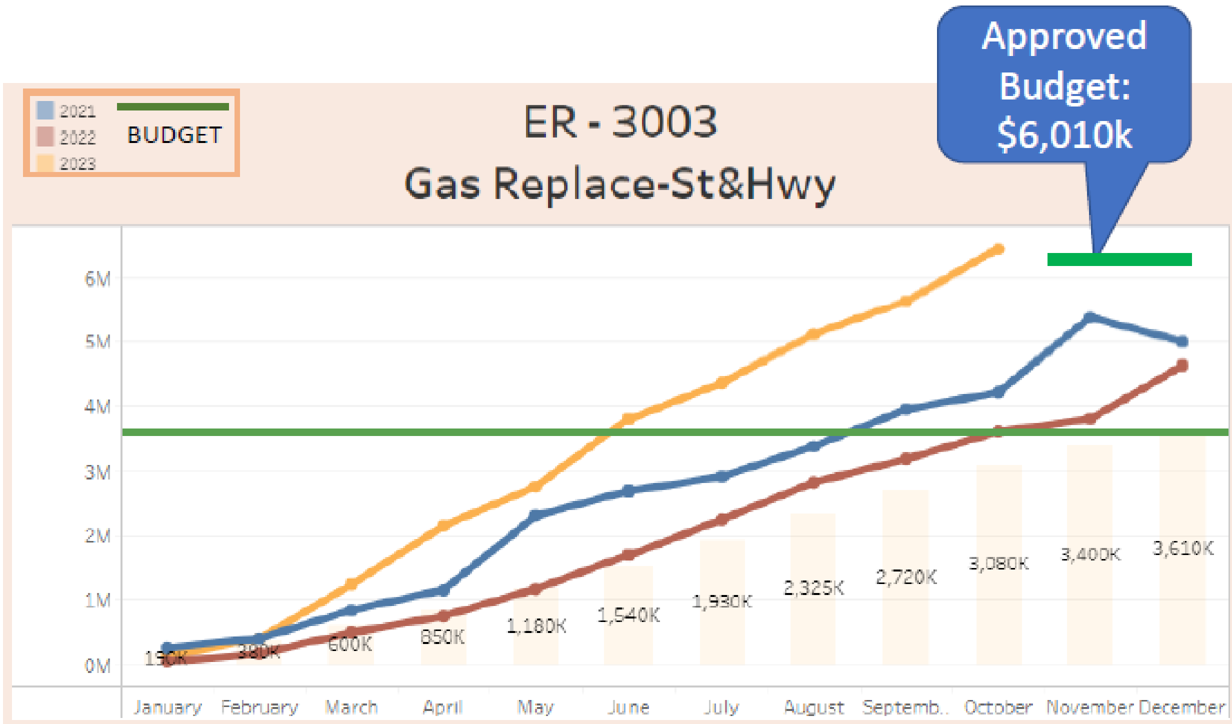
1.1.1 Identify what has changed such that the current approved amount is not sufficient.

The spend rate has continued to be greater than previous years. The number and size of the projects is greater than last year, especially in Medford and Spokane.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

This is considered work in request of others.

1.1.3 Please reference analysis or information that support the problem and attach to this document.



1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

None noted.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The projects in process can not be delayed due to obligation put upon Avista by others. No reasonable alternatives are available for this programmatic work.

Gas Replace Street & Hwy Program, ER 3003

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

This is still prudent as we need to stay in good standing with our franchise agreements.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

Confirmed, no change.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Jeff Webb	BC Owner	Jeffrey A Webb	11/17/23
Alicia Gibbs	BC Sponsor	Alicia Gibbs	11/17/23
	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

ER 3010 – Gas Transient Voltage Mitigation Program

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This program addresses high voltage hazards that can exist on certain gas piping that is adjacent to electric systems. Originally, this program had a 2023 approved budget of $750,000. Due to a shortage of engineering, project management, and real estate resources, projects under this program were delayed. Two Business Case Change Request Forms were submitted during the year, revising expected spending to $320,000.
It was anticipated that a $650,00 project in Idaho would be completed in 2023 and transfer to plant at that time. Two grounding wells could not be completed, and their installation was delayed until 2024. Once those installations are complete the project can be transferred to plant.

The planned transfer to plant was $965,000. The actual transfer to plant was $78,325.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Capital spending levels are reviewed monthly. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, gas leadership agrees on submitting funds requests or releases, if necessary. Those funds forms are submitted to the company's Capital Planning Group (CPG) for funding consideration. Approved Business Case Funds Request(s) are included with this form.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets for this period.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: DIRECTOR SIGNATURE:

X Jeffrey A Webb X Alicia Gibbs

Gas Transient Voltage Mitigation Program, ER 3010

EXECUTIVE SUMMARY

Federal code CFR 49.192.467(F) requires that pipelines located near electric transmission systems must be protected from damage caused by faults on the transmission system. Avista has experienced safety issues, including fires at regulator stations and damaged equipment, due to electrical arcing caused by faults on adjacent electric power systems. Fault events of electric distribution or transmission systems can create high voltage levels on nearby steel gas piping. This is due to either power system current arcing onto the pipe, or more typically, through electromagnetic induction. Sometimes gas systems experience 'steady-state' voltage. In these situations, there is an induced voltage on the pipe at all times that comes from nearby electric lines. These situations don't cause arcing, but the voltage level can be high enough to be a personnel safety concern, as well as a cause of pipeline corrosion.

The purpose of this program is to identify high pressure gas piping systems that are at risk of these conditions, identify gas systems that have high steady state voltage, and to then install mitigative measures to reduce the risk from these hazards. These efforts will protect the pipeline and equipment from being damaged, while also reducing employee exposure to touch voltage hazards. Common approaches to mitigation include the installation of grounding systems, gradient control mats, and other equipment that reduces the presence of dangerous voltage differentials on pipeline facilities.

This work is a direct effort to prioritize the safety of Avista's employees. Avista's customers and contactors also benefit from the improved safety of these systems as some of Avista's infrastructure is aboveground and therefore accessible to the general public.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Jeff Webb*	*Initial draft of original business case*	*12/17/2021*
1.2	*Tim Harding*	*Updated to the refreshed 2022 Business Case Template*	*9/01/2022*
1.3	*Shontelle Wilson*	*Updated to the refreshed 2023 Business Case Template*	*4/6/2023*
2.3	*Tim Harding*	*Updated to the refreshed 2023 Business Case Template*	*4/18/2023*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	5/5/2023

Gas Transient Voltage Mitigation Program, ER 3010

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**500,000**	**500,000**
2025	**250,000**	**250,000**
2026	**250,000**	**250,000**
2027	**250,000**	**250,000**
2028	**250,000**	**250,000**

Project Life Span	***10 Year***
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner | Sponsor	Tim Harding / Jeff Webb | Alicia Gibbs
Sponsor Organization/Department	B51 – Gas Engineering
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Buried steel natural gas pipes in close proximity to electric conductors can have high AC voltage present. The power lines induce this voltage on the pipe, either constantly, or during fault conditions. Industry standards, including AMPP Standard Practice SP0177 suggests that, for safety reasons, steady-state pipeline voltages should not exceed 15 volts. Systems experiencing voltages higher than this should be studied, and mitigation measures put in place to reduce system voltages.

Federal code CFR 49.192.467(F) requires that pipelines located near electric transmission systems must be protected from damage caused by faults on the transmission system. The mitigation schemes and equipment used to address fault voltage concerns often overlaps what is used to address steady-state voltage hazards. Fault incidents on nearby electric systems can lead to a significant voltage rise on the gas main – hundreds or thousands of volts. Gas systems are not designed to support these voltage levels, and because of this electric arcing between components can occur. This arcing damages equipment, and will burn holes through gas-carrying components, leading to gas leaks and fires. Personnel working on these gas systems during a fault event can be exposed to fatal voltage levels.

Gas Transient Voltage Mitigation Program, ER 3010

Between 2017 and 2021, there were five electric fault incidents that caused arcing on gas facilities, resulting in blowing gas and fire. Each one of these incidents caused equipment damage and required emergency response from company personnel.

The constant presence of AC voltage on a pipeline can also lead to corrosion. AMPP Standard Practice SP21424 addresses this issue and gives guidance on testing, monitoring, and mitigation of this issue. AC corrosion can occur on pipelines with less than 15 volts, so systems without shock hazard risks may still have this issue. Because of this, AC corrosion risks must be monitored separately from the other two risks listed above.

1.2 Discuss the major drivers of the business case.

The primary driver for this business case is Mandatory & Compliance. This program addresses safety hazards and integrity concerns on high pressure steel gas mains. This benefits customers by reducing corrosion risks, as well as eliminating hazardous voltage levels on above-ground gas facilities – facilities that sometimes are accessible to the general public.

Based on Federal code CFR 49.192.467(F) "Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices." This business case supports this federal code requirement. Federal fines for not meeting code requirements are not prescribed but can range to a maximum daily fine of $257,664 per day and a maximum total of $2,675,627 per violation.

Fault events cause damage to the gas system, and also cause unsafe conditions when gas is released and when it ignites. By mitigating areas that are prone to damage, the likelihood of these incidents occurring is reduced. The installation of mitigation equipment reduces O&M expenses. The two main reductions in these costs are due to fewer fault damage incidents that require emergency response, and the reduced need to follow special safety procedures when doing construction or maintenance on the system. The average cost savings per year in O&M is $7,200.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

There are multiple gas systems with known high-voltage hazards present. Between 2017 and 2021, there were five electric fault incidents that caused arcing on gas facilities, resulting in blowing gas and fire. Not mitigating these systems will result in the continued prevalence of electric fault incidents, as well as exposing employees to potentially hazardous steady-state pipeline voltages. Mitigation methods described in this program are a proven way to resolve these issues. This work must be done, and delaying the process puts system integrity and workers at an increased level of risk for each year of the delay.

Gas Transient Voltage Mitigation Program, ER 3010

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's organizational focus to maintain safe and reliable infrastructure to achieve optimum life-cycle performance, in a safe manner for our customers. As stated in the summary, equipment damage and fires have resulted in an unsafe environment. This program focuses on pipelines that will be damaged by nearby electric systems, or those that will expose employees and the general public to unsafe voltage levels.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

As previously stated, five electric fault incidents have already occurred on Avista's gas system. The following image is of pipe damage that occurred from a fault incident that occurred on or around the date of 1/24/14.

Image 1. Pipe Damage from Fault Incident

The next image documents the ignition that occurred as a result a different fault incident in 2017.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Gas Transient Voltage Mitigation Program, ER 3010

Image 2. Ignition from Fault Incident

Similar photographic evidence documents the results from the other four fault incidents. To date, two studies have been performed by consulting engineering firms on the specific gas systems that have experienced multiple arcing incidents due to electric system faults. These studies have yielded reports and mitigation designs.

These studies use computer models to simulate the interaction between power lines and nearby buried steel pipelines. The computer models take into account the locations and characteristics of the power and gas systems, as well as the soil characteristics. The software simulates both steady-state conditions and fault events that occur on the electric system. It then determines the AC (Alternating Current) voltage levels that will be on the pipeline at these times.

For the two studies conducted, the computer simulations showed worst-case pipeline voltages of 2,000 V_{AC} and 4,000 V_{AC} on the two different systems. Voltage levels of this magnitude can cause arcing at gas equipment, and represent a fatal shock hazard.

The second part of each study involved putting together a mitigation design. High voltage hazards can be mitigated in different ways. There are three general schemes that are used to reduce these hazards:

1. Grounding – Steel gas pipes are coated to reduce corrosion. The better the coating on the pipe, the higher voltage the pipe will experience due to nearby power lines. By grounding the steel pipeline to the adjacent soil, the voltage rise on the pipeline is reduced. Gas systems have cathodic protection systems, which aren't compatible with a traditional grounding system. It's beyond the scope of this document to describe, but note that special grounding designs are required.
2. Equipotential Mats – At above-ground gas facilities, such as regulator stations, personnel can come in contact with gas piping. If the piping is at a high voltage level, a hazard can exist when the piping is touched. The danger exists because there is a voltage difference between the pipe surface (hand contact) and the ground (foot contact). This voltage difference causes current to flow through the body, resulting in a shock. Equipotential mats are a metal grid that is placed 6-12" below ground in areas around above-ground gas pipes. The grid is connected to the pipe with wires. If the pipe voltage rises, the grid will rise to the same level. This eliminates the high voltage difference between the hands and feet, eliminating the shock hazard.
3. Insulation – Similar to the example above, this is another way to reduce shock hazards that can occur when contacting gas systems. In this case, 6-12" of high resistance gravel is added in areas around above-ground gas pipes. The resistance of the gravel is high enough that only a non-lethal current level would flow through the body if the gas pipe was touched.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The requested level of spending for this program allows the high priority projects on systems with known hazards to be completed. Outside consulting engineering firms have performed studies and helped identify which mitigation approach is appropriate for each known hazard area. As previously stated, mitigation approaches include: grounding, equipotential mats, or insulation. These projects are addressing serious system integrity and safety issues. A reduced level of funding will slow the installation of mitigation equipment, and delay resolving known system integrity and safety risks. For projects to be considered in this program, they must exhibit issues that would put them in violation of the Codes and Standards listed in Section 1.1 of this document. As projects are completed, these systems will become compliant with these requirements. As more systems are addressed, fewer will require mitigation and the program budget can be reduced.

Gas Transient Voltage Mitigation Program, ER 3010

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Execution of this program ensures that Avista avoids the risk of federal fines resulting from noncompliance with Federal code CFR 49.192.467(F). Federal fines for not meeting code requirements are not prescribed but can range to a maximum daily fine of $257,664 per day and a maximum total of $2,675,627 per violation.

This program will also directly reduce O&M expenses related to extensive safety procedures currently required each time an employee works on a gas system that has potential voltage hazards, and the O&M labor that results when fault damage occurs. These are expanded on further in section 2.3, but average approximately $9,075 each year.

This business case is intended to address risk reduction and Avista's ability to maintain compliance in the states we operate within. The program is aimed at maintaining safe and reliable systems for our employees and our customers. Additional risk mitigation that is not currently quantified is the serious potential of Avista employee or customer contact with fatal voltage levels that may be present on the gas system.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	None	$0	$0	$0	$0	$0
O&M	Labor related to extra safety procedures	$5,100	$5,200	$5,400	$5,600	$5,700
O&M	Labor and materials to respond to fault damage events and make repairs.	$3,400	$3,500	$3,600	$3,700	$3,800

The installation of mitigation equipment reduced O&M expenses. The two main reductions in these costs are due to fewer fault damage incidents that require emergency

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

response, and the reduced need to follow special safety procedures when doing construction or maintenance on the system.

When a fault event occurs that damages equipment, immediate response is needed by an Avista First Responder. There is then follow-up required by Gas Engineering to determine the cause of the incident.

In gas systems with known high voltage hazards, special safety procedures are required when contacting gas facilities that have not been mitigated. These safety procedures can include the use of rated rubber gloves, or the use of portable equipotential mats. These mats reduce touch voltage hazards and are similar to the gradient mats described in section 1.5. Setting up these mats is time consuming and once a facility has had permanent mitigation installed their use is no longer required. In addition, safety procedures require ongoing training for every employee working on the affected system.

2.4 Summarize in the table, and describe below the INDIRECT offsets (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M	Labor and materials to repair system leaks caused by AC corrosion	$3,600	$3,700	$3,800	$3,900	$4,000

The installation of mitigation systems reduces pipeline voltage. This decreases the chance of AC corrosion occurring, thereby reducing the chance of leaks from occurring on the pipe. High voltage hazards on pipelines create system integrity and safety risks. The costs associated with some of these risks can be hard to predict. Below are estimated cost ranges related to different risks.

Risk Probability Definitions:

Very High (VH)	Risk event expected to occur
High (H)	Risk event more likely to occur than not
Probable (P)	Risk event may or may not occur
Low (L)	Risk event less likely to occur than not
Very Low (VL)	Risk event not expected to occur

Risk Avoidance Over Time and the Cost of Doing Nothing:

#	Risk	Risk Over Time: 1 Year	2 Years	5 Years	10 Years	15+ Years	Cost Estimate
1	Regulatory Fines	L	L	P	P	H	$257,664 per day per violation (Max)* $2,576,627 Total (Max)*
2	Pipeline Leak	L	P	P	H	H	$5,000 to $150,000 per site (site dependent)
3	Pipeline Failure & Outage	VL	L	L	H	H	$150,000 to $3,000,000 per site (site dependent)
4	Negative Reputation	L	L	P	H	H	Erosion of PUC and Public trust
5	Employee & Public Safety	H	H	H	VH	VH	Lost time, lawsuits, healthcare , etc. (varies)

*Regulatory fines present a daily and overall maximum value per violation in accordance with 49 CFR Part 190.223. However, these values are not necessarily an accurate representation of how much Avista would be fined for any specific violation. The actual amount is likely to be much lower since Avista has an ongoing reputation and history of investing in programs related to safety and non-compliance issues. However, it is a bookend reminder from which to characterize the regulatory risk associated with chronic and/or egregious non-compliance, especially in the event of a pipeline safety incident (i.e. failure). Therefore, Avista must continue to demonstrate an ongoing commitment to compliance and pipeline safety to ensure favorable future outcomes with respect to regulatory penalties. (Actual penalty amount is at the discretion of the state or federal agency).

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: Fund program at lower level

The current funding level per year is the minimum funding level required to address the highest priority mitigation projects. Any funding level below this amount means that high priority projects will not be addressed. Not mitigating the system will result in excessive prevalence of electric fault incidents. During these incidents, electric arcing can occur on gas facilities. This can, and has, lead to gas leaks and fires. Knowingly allowing dangerous incidents like this to continue is not acceptable and leads to increased risk to employee and customer safety.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The completion of mitigation projects under this budget will have a positive impact on Gas Operations. Because there is currently a known safety issue, additional burdensome procedures are required when company personnel do construction and maintenance work on these systems. After the mitigation projects are complete, many of these additional safety procedures will no longer need to be followed.

This program is being tracked and communicated through documentation updated by Gas Engineering in the SharePoint site. Identified projects as well as the status of these projects (complete, in progress, etc.) can be found on this document. Each completed project documents the success of this program in reducing the risk of a fault condition occurring, and/or of an individual coming into contact with potentially hazardous voltage levels.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is designed as a 10-year program. Projects that are performed under this budget can be both large and small. Smaller projects will typically transfer to plant monthly, while larger projects that take several months to complete will transfer to plant upon project completion. As completion rates occur, the timeline and forecasts will be updated accordingly.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

An engineer in the Gas Engineering group serves as the AC Mitigation Program Manager. The Program Manager oversees projects designs, construction, and the program budget. The Program Manager meets quarterly with representatives from Gas Engineering, Cathodic Protection, and Gas Compliance to review current and planned projects. Project are prioritized by the group. If any changes to the budget for the year are needed, the Program Manager proposes a budget change and justification that must get approval from the Business Case Sponsor before it is brought before the Capital Planning Group. If additional funds are not approved, then the remaining work is reduced to remain within budget.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Transient Voltage Mitigation Program, ER 3010* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jeffy a Webb	Date:	5/4/23
Print Name:	Jeff Webb		
Title:	Mgr Gas Engineering		
Role:	Business Case Owner		

Signature:	Alicia Gibbs	Date:	5/4/2023
Print Name:	Alicia Gibbs		
Title:	Director of Natural Gas		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Transient Voltage Mitigation Program, ER3010

1.0 CHANGE REQUEST #1 – 8/25/23

Previous Requests	Requested	Approved
5-Year Plan	$750,000	$750,000

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
09-2023	186,666	$750,000	-$300,000	$450,000

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	9/13/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

The current approved budget for 2023 is $750,000. This amount was based on estimates assembled in 2022 for the then-new program. There has been a lack of engineering and project management resources available to complete projects at the initially planned pace.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The current justification narrative for this program is still valid.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Transient Voltage Mitigation Program, ER3010

Name	Role	Signature	Date
Jeff Webb / Tim Harding	BC Owner	Jeffrey A Webb	8/25/23
Alicia Gibbs	BC Sponsor	Alicia Gibbs	
	FP&A		

Transient Voltage Mitigation Program, ER3010

1.0 CHANGE REQUEST #2 – 10/12/23

Previous Requests	Requested	Approved
5-Year Plan	$750,000	$750,000
9-2023	$450,000	$450,000

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
10-2023	$171,162	$450,000	-$130,000	$320,000

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	10/31/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

The original approved budget for 2023 was $750,000. This amount was based on estimates assembled in 2022 for the then-new program. There has been a lack of engineering and project management resources available to complete projects at the initially planned pace.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

This program addresses safety and integrity concerns related to high voltage that may be present on certain steel gas systems. The program was created in response to electric arcing incidents on gas systems that caused gas releases and fires.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

See ER 3010 Business Case section 1.3.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

See ER 3010 Business Case sections 2.3 and 2.4.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

See ER 3010 Business Case section 2.5.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The proposed reduction in funding does not change the importance of this program.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The current justification narrative for this program is still valid.

Transient Voltage Mitigation Program, ER3010

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Jeff Webb	BC Owner	Jeffy a Webb	10/12/23
Alicia Gibbs	BC Sponsor	Alicia Gibbs	10/12/2023
	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Generation, Substation & Gas Location Security

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Generation, Substation & Gas Location Security (GSGL) business case is intended to fund generation, substation, and gas location physical security projects. Recent domestic security events and credible threats across the U.S., as well as local events on electric utility infrastructure heightened the urgency to increase Avista's physical security. This business case measures electrical substation facilities.

The GSGL business case was expected to transfer to plant approximately $459k and instead transferred approximately $1.2M. This equates to approximately $730k more than expected in 2023. The original approved amount was not sufficient to adequately and immediately address the identified transmission and distribution substations in Idaho and Washington that required additional physical security hardening to reduce the impact of those emerging threats. Thus, the corporate priority for 2023 was directed to focus on improving security at specific substation locations. The new priority for 2023 drove a $500,000 capital funding request and subsequent increase to the business case to meet the enhanced substation security requirements.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The CPG funds change requests are attached detailing the requested allocation increases.

ET_GSGL_In Year Business Case Funds Change Request_Signed_03-2023.pdf - $500k request to fund two projects encompassing 13 substations in WA and ID identified for physical security improvements due to their higher risk of being targeted for domestic terrorism.

The additional $230k of over transfer was due to a few projects not completing in 2022 that transferred in 2023.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revised offsets associated with this change.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: DIRECTOR SIGNATURE:

X DocuSigned by:
6456C8EEF402467...

X DocuSigned by: Clay Storey
B70F95F7961D4B6...

Generation, Substation & Gas Location Security

1.0 CHANGE REQUEST #1 – MARCH 6, 2023

Previous Requests	Requested	Approved
5-Year Plan	$500,00	$500,000
CR01	$1,000,000	

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
03-2023	$-27,800	$500,000	$1,000,000	$1,500,000

Type of Change	In-year Update
Primary Reason for Change	Timing Change, Externally Driven
Response needed by	3/31/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

Recent domestic security events and credible threats across the U.S., as well as local events on electric utility infrastructure has heightened the urgency to increase Avista's physical security measures at electrical substation facilities. The current approved amount is not sufficient to adequately and immediately address the identified transmission and distribution substations in Idaho and Washington that require additional physical security hardening to reduce the impact of these emerging threats.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

While generally electrical substations are unmanned facilities across the U.S. and our service territory, a need for physical security hardening is required as the threat environment evolves. Vandalism, theft and sabotage are no longer the only threats. There is a rise in suspected suspicious behavior, physical attacks, ballistic attacks, and unmanned aircraft systems conducting surveillance.

Additionally, recent attacks on substations in North Carolina and in Western Washington have heightened the risk probability of a similar event happening in our service territory. The longer we go without hardening physical security at the identified electrical substations, the greater the risk of a similar event happening in our substations that could have a significant impact on our customers and stakeholders who are dependent on these substations.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Federal officials (Cybersecurity & Infrastructure Security Agency and the Department of Energy) and incident investigators are calling for heightened security measures due to recent attacks at various substations in North Carolina and Western Washington. For example, the power outages over the Christmas holiday in Western Washington “left thousands [of customers] in the dark and cold and put some who need power for medical services at extreme risk”, as stated by Nicholas Brown, the U.S. attorney for the Western District of Washington.[1]

In response to these emerging threats, Avista’s senior leaders have requested that this risk be mitigated adequately and immediately.[2]

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

Layered physical security is important to protect an electrical substation and each substation requires a security plan tailored to its unique operating environment. A dedicated team of substation engineers, physical security experts, network resources, and electricians will begin with site assessments, design a tailored mitigation plan for each substation facility, followed by a schedule to procure and begin installation and testing. While the overall performance of each electrical substation will stay intact, video surveillance and other physical security hardening measures will aim to deter, detect, and delay a threat and capture video surveillance evidence to aid investigations.

There is a minor O&M impact in camera software licensing, as well as minor labor increases for ongoing routine maintenance of cameras at each substation location. However, the additional minor camera maintenance efforts will be added to existing routine maintenance procedures to minimize the O&M impact. This investment will not result in O&M offsets. It is a preventative risk-based investment to reduce or minimize the impact of an attack at a set of Avista electrical substations.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

Doing nothing is not an option. The alternatives or levels of layered security at each substation will vary and depend on the site assessment. Substation site assessments are being treated as sensitive information and will only be shared on a need-to-know basis. Alternative solutions to physical security hardening included adding ongoing security patrols, installing temporary wireless cameras requiring battery swaps, and renting a temporary solar powered security camera trailer at each substation location. All these alternatives have higher ongoing O&M costs and other challenges, such as how many patrols per day/night at each site, how often will camera batteries last during inclement weather, and how safe or secure is a rented solar powered security camera trailer at these unmanned facilities.

Moreover, the damage estimated at two of the four substations targeted in Western Washington is estimated at $3 million and will take up to 36 months to repair. The utility will run mobile transformers at each facility while they make the required repairs.[3] Although the financial cost may not appear high to repair damaged equipment, the lead time on substation equipment replacement could be 12-18 months depending on the manufacturer of the equipment. Additionally, should Avista not have mobile transformers available, the rental costs may exceed the capital investment over the

[1] 2 Charged in Attacks on Substations in Washington State - The New York Times (nytimes.com)
[2] Our Goals 2023 - Perform (sharepoint.com)
[3] 2 Charged in Attacks on Substations in Washington State - The New York Times (nytimes.com)

months or years during repair. Lastly, and perhaps even more importantly, a loss of life to those needing power for medical devices due to an extended power outage would be devastating.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

Avista's electric customers and stakeholders depend on the reliability of electrical substations to energize their businesses or homes. Protecting these critical assets is pivotal and prudent to providing a safe, secure, and reliable infrastructure despite the changing threat landscape.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid. However, given the heightened probability of risk and associated urgency, the narrative will be updated to incorporate change in the threat landscape.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Andy Leija	BC Owner	DocuSigned by: 6456C8EEF402467...	3/3/2023
Clay Storey	BC Sponsor	DocuSigned by: Clay Storey B70F95F7961D4B6...	3/3/2023
	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

HMI

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Anticipated TTP dates changed for a handful of reasons. Deployment windows shifted in response to resource availability and longer than expected design timelines. Additionally, some sites were moved to reduce impact to the facility or better synchronize with other projects and sites.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Complete_with_DocuSign_BCFCR_HMI_Control_Sof

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

N/A

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Michael Truex
Michael Truex (Feb 23, 2024 11:53 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 23, 2024 12:36 PST)

<HMI Control Software (4192)>

1.0 APPROVED 2024 TO 2026 CAPITAL BUDGET

Year	Funding Impact				Offsets Impact		TTP Impact	
	Requested Capital Budget	Approved Capital Budget	Current Forecasted Need	Variance (Approved vs Need)	Budgeted Benefits /Offsets[1]	Revised Benefits /Offsets	Budgeted TTP[2]	Revised TTP
2024	$3,000,000	$2,500,000	$3,500,000	$1,000,000	NA	NA	$3,400,000	NA
2025	$2,500,000	$2,500,000	$2,750,000	$250,000	NA	NA	$4,100,000	NA
2026	$300,000	$300,000	$500,000	$200,000				
*2027**								
*2028**								

**If applicable or useful to provide additional context or consequences.*

THIS SECTION MUST THOROUGHLY DESCRIBE THE IMPACT TO THE PROJECT/PROGRAM OF THE APPROVED FUNDS VERSES WHAT WAS REQUESTED. THE IMPACT WOULD INCLUDE ADDITIONAL RISKS (FINANCIAL OR OTHER), SCHEDULE OR SCOPE CHANGES, LABOR, AND/OR IMPACTS ON OTHER BUSINESS CASES.

Explain what work is driving the funding need:
A combination of events have changed the overall delivery of a handful of sites.

Specifically, Rathdrum's cutover will need to be moved into the run off season (2024) to avoid impacts to the plant. Long Lake and Little Falls delivery was brought closer together to minimize overlap between Wonderware and Ignition.

Additionally, ET's understanding of the scope of work has improved dramatically. With that understanding comes better forecasting. ET components projected spend at complete are roughly 25% over budget.

Lastly, The OIT solution that had been originally spec'd does not appear to be viable on all sites. A different solution is being vetted and priced.

Funding consequences for future years from requested to approved:
2024 represents the single biggest year for installs on HMI. With Rathdrum, Long Lake, Little Falls, and a portion of Noxon (ancillary systems) all slated for 2024. The lack of funding for this work could create slow downs which ultimately will cost the project more. Incomplete funding could also potentially require that HMI outages take place outside of annual maintenance windows, thus costing the company more in lost generation in order to keep schedule.

Consequences to GPSS' 2030 Department Goals:
The current project schedule shows most sites cutover by end of 2025, with the execption of Noxon's generation units slated for Q1 of 2027. Assuming that the reduced funding does not continue in future years and is eventually adequately funded within the 2030 window, the 2030 goal should not be impacted.

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.

<HMI Control Software (4192)>

Other Risks:
Labor/Engineering resource constraints already create a very real risk for completion of HMI on the forecasted timeline. Adding budget constraints will only negatively impact the pace that the limited crews can perform the necessary work.

2.0 ACKNOWLEDGEMENT

The undersigned acknowledge they have reviewed the approved funds and agree with the impacts to the project/program.

Name	Role	Signature	Date
CJ Mcmahon	Person Filling Out this Form	DocuSigned by: CJ Mcmahon F4FB6F02AEC1407...	Oct-10-2023 | 1:44 PM PDT
Michael Truex	BC Owner	DocuSigned by: Michael Truex B0401E01AC1543C...	Oct-10-2023 | 1:53 PM PDT
Alexis Alexander	BC Sponsor	DocuSigned by: Alexis Alexander EA27BABA767F467...	Oct-15-2023 | 8:56 PM PDT
NA	Steering Committee (If applicable)	NA; Alexis Alexander is on the steering committee for this project	

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Identity and Access Governance (IAG)

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

As stated in the 2022 Provisional Capital Report, this project experienced delays pushing expected transfer to plant from 2022 into 2023, see attached explanation from 2022.

This business case created Avista's new Identity and Access Governance (IAG) program. The initial project that addressed potential SOX compliance issues was expected to transfer to plant in 2022. However, the project extended an additional year due to far more technical challenges with integration than expected. Additionally, the professional services support organization contracted to provide guidance on the integration efforts was plagued with the attrition of key technical expertise throughout the project. Therefore, the variance in transfer to plant is the result of an additional years' worth of work to meet the compliance driven scope of the project.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved.

- Identity and Access Governance - Capital Additions Variance Form_Signed 2.pdf
- Identity and Access Governance Update - Jan 2023 FINAL.pdf

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revised offsets associated with this change.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: Mar-18-2024 | 12:50 PM PDT

X DocuSigned by: 6456C8EEF402467...

DIRECTOR SIGNATURE: Mar-18-2024 | 1:56 PM P

X DocuSigned by: Clay Storey B70F95F7961D4B6...

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Identity and Access Governance

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2022), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Avista's current Identity and Access Governance (IAG) program is highly manual, time consuming, cumbersome and prone to human error. This has led to consistent failures of related controls around access to systems or facilities for individuals who have either changed roles in the Company or left the Company and should no longer have previous role access. The IAG program will create role-based profiles, define system privileges, automate access management, and facilitate regular user access review and validation. This program was just started in 2022.

The Identity Access Governance business case planned transfers-to-plant in the filed Washington GRC was approximately $672k and did not end up transferring anything in 2022. This is now expected to transfer-to-plant in June of 2023.

There is only one project within this business case called *Identity and Access Governance Implementation phase 1,* which is a new complex technology for Avista. This project was unable to go live in 2022 due to a variety of resource constraints, which caused delays in the timeline. Hardware delays in the model office environment also contributed to a delay in the project timeline.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. Please see the executive update attached for further details regarding this delay.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

These projects have no identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by:
6456C8EEF402467...

DIRECTOR SIGNATURE:

X DocuSigned by: Clay Storey
B70F95F7961D4B6...

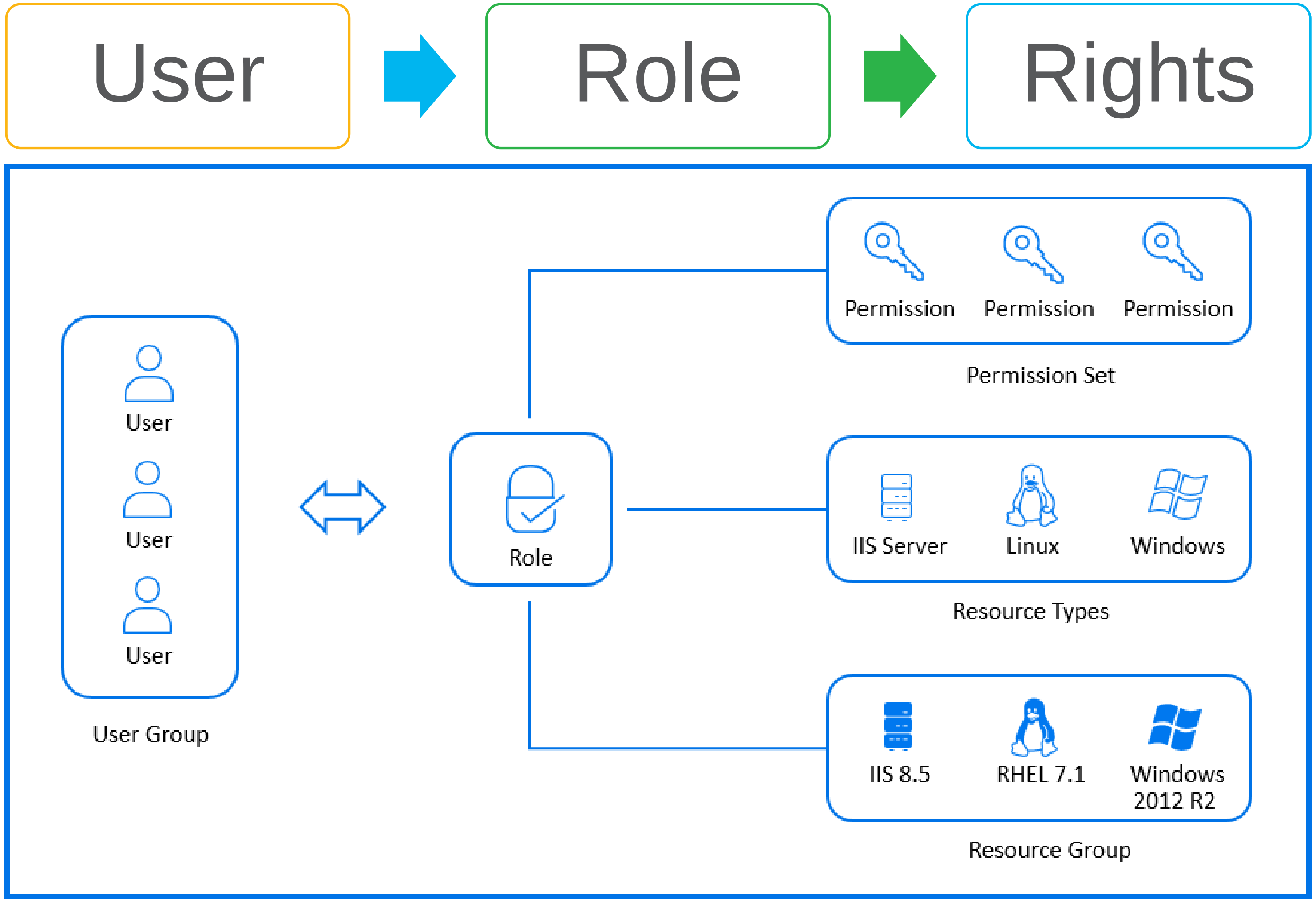
Role Based Access Control: Executive Update

(Ryan Krasselt and Jim Kensok)

January 2023

FOR DISCUSSION AND PLANNING PURPOSES

Role Based Access Control (RBAC) – Update



- Access may be based on job function or role
- One to many combination
- Elimination of rights requires role and process refinement
- Straddling multiple roles can continue to present challenges
- User Access Reviews will be critical to manage user rights and refine roles
- Future state to include other than SOX systems

RBAC – Update

Original Go-Live Schedule: 9/2022

Challenges:

- Vendor resource availability
- Technical skillset varied internally and externally
- Deployment and data standards not established; new solution to Avista

Current Go-Live Schedule: 5/2023

Potential Risk:

- Non-Active Directory managed SOX applications may be a challenge
  - FSS (JET, Red, Cashbook), PayCourier (Remittance), Nucleus, AMR TWACs

RBAC – Update

Relevant Milestones	Date
1. Implement Identity Access Management Software	In Progress
2. Integrate Target Applications, Servers, and Databases (e.g., AD, Cognos, CC&B, WinOS, Oracle, UltiPro, Linux, MV90)	Mar 2023
3. Design and Configure System to Run User Access Reviews	Apr 2023
4. Train and Support Staff to Manage and Operate Software	Apr-May 2023
5. Perform User Access Reviews in Software Solution	May 2023
6. Define Roles Associated with SOX Systems (e.g., Accounting, Finance, Treasury, IT, etc.)	Aug 2023
7. Create Role Based Access in Software	2023-2024
8. Expand to Applications Beyond SOX Systems	Ongoing

Q&A

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

KF_Fuel Yard Equipment Replacement

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Please refer to the 2022 Capital Additions Variance Explanation Form (attached). The previously submitted 2023 Budgeted TTP was $30,367,127. Of that, over $29M was Transferred to Plant in September 2022, earlier than originally planned, which is the reason for the 2023 variance.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This project was governed by a Steering Committee representing Power Supply, Environmental and Operations, which agreed on the approach in 2022 to proceed with the early TTP. Please refer to the 2022 form (attached).

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

Early TTP of this project reduced major maintenance expenses on the aging equipment and reduced AFUDC costs incurred by the project. Please refer to the 2022 form (attached).

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Michael Truex
Michael Truex (Feb 23, 2024 11:55 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 23, 2024 07:47 PST)

KF_Fuel Yard Equipment_Replacement

EXECUTIVE SUMMARY

The existing system does not allow the plant to operate consistently with safe best practices, environmental stewartship and production. The fuel handling equipment operates at or beyond its absolute limit. In the early 1980's Washington State increased the legal hauling weight and the trucking industry transitioned from 48' trailers to 53' to increase their payload. This change created a number of production and safety challenges for the plant operations and contractor support. The system does not meet current environmental regulations for visibility and particulate matter (PM) emissions for intermittent periods. Although the primary drivers for the project are safety, environmental, and reliability, we do expect a decrease in O&M. With all benefits included, Financial Planning and Analysis has concluded that this is a prudent project. The project will proceed over a two year period with $12 million in 2019 and $10 million in 2020. (7/8/2021 Update: *Project timeline has been extended and adjusted and the current plan will continue into 2021 with the underground utilities installed, major equipment purchased and truck dumpers commissioned. 2022 will be construction of conveyance, processing and control buildings and installation of the hog and disc screen*.)

Replacing the major fuel handling equipment will create a safer system for employees and contractors as the new dumpers will be designed to lift current truck lengths and weights. The major equipment will be designed with covers and passive dust control utilizing new dumper technology and conveyance covers. (*7/8/2021 Update: Scope has been reduced to reduce project costs by changing the truck route, eliminating a pass through travel route, reduction of an enclosed processing building, eliminating a conveyor through a more compact layout, eliminating a new power supply from the distribution line near the plant site and delay of replacing the existing #3 fuel conveyor*)

This project will impact customers in service code Electric Direct jurisdiction Allocated North serving our electric customers in Washington and Idaho.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Greg Wiggins*	*Initial draft of original business case*	*05/01/2018*	
1.0	*Thomas Dempsey*	*Edit Draft / Executive Summary*	*07/03/2018*	*Added content*
1.1	*Greg Wiggins*	*Edit Approved Business Case to new Template*	*07/08/2021*	*New Template / Update major project changes Scope, Schedule and Budget*

KF_Fuel Yard Equipment_Replacement

GENERAL INFORMATION

Requested Spend Amount	$22,000,000
Requested Spend Time Period	*2 year (7/8/2021 Update project will be 5 year)*
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Greg Wiggins | Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Execution *(7/8/2021 Update project is in execution phase)*
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

The major fuel yard equipment being considered for replacement includes the truck dumpers, fuel hog, truck scale, and conveyance systems.

Truck Scale - The truck scale is used to account for the quantity of fuel received from each truck delivery. The truck drivers scale in upon arrival to the site and the scale out after completing the unloading process.

Truck Dumpers - The truck dumper receives the delivered fuel by elevating the trailers. Fuel exits the rear of the trailer into a receiving housing.

Fuel Conveyors - Fuel conveyers move the fuel from the truck dumpers to a metal detection system, then to the fuel hog system and finally out to the fuel yard.

Hog and Disc Screen - The fuel hog is a device that clarifies and conditions the fuel so that it is the proper size required for optimum combustion.

1.1 What is the current or potential problem that is being addressed?

There are three key components that comprise the business problem presented by the current fuel yard.

1. Safety
2. Environmental
3. Reliability

KF_Fuel Yard Equipment_Replacement

These three components are summarized as follows:

The Kettle Falls Generating Station is a biomass fueled power plant that processes on average 500,000 green tons of waste wood from area sawmills. The wood delivered to the facility is trucked in by contractors utilizing semi-trucks and chip trailer. On average the plant received 65-80 loads of fuel each day with surges to 100 deliveries in a 24 hour period.

The plant's original design was just prior to Washington State increasing the legal haul lengths and weights. All the equipment was designed for 48' trailers and the new law change in 1985 allowed drivers to haul with 53' trailers. When the drivers enter the facility the load is weighed on a State certified scale to determine amount of fuel being delivered. The longer trailers do not completely fit on the scale without the drivers lifting the tag axle on the trailer. The plant's delivery tracking system captures the gross weight of the truck and trailer into the 3Log financial interface application. Through this system vendors and suppliers are paid for their services. Due to the longer trailers and short scale drives can "cheat" the system by not positioning the load correctly on the scale. Each load is reviewed through the 3Log (TWA) Truck Weight Analyzer. When an infraction is found the surveillance video is reviewed and sent to the hauling company for reconciliation. Manual adjustments are made in the system to ensure proper payment to the supplier.

Truck was intentionally positioned short on the scale.

TWA show drivers manipulating the scale due to being overloaded.

The fuel is offloaded truck trailers into the receiving hoppers via a truck dumpers. The wood is then conveyed, screened and sized prior to being transferred out to the fuel inventory pile. The Fuel Equipment Operators then manage the fuel inventory utilizing D10 Cat dozers to stack out incoming fuel and stage inventory to be processed in the plant.

Due to the higher legal hauling limits in Washington the longer truck/trailer configurations require the truck drivers to unhitch the trailer from their trucks. This unhitching process not only increases truck turnaround time and increases hauling costs to plant, it adds a difficult step. Although not the primary factor, a contractor fatality in 2013 occurred while going through this step in the process. One driver was attempting to unhitch his trailer from the truck and was working with another driver to get the hitch pin released when the accident occurred.

KF_Fuel Yard Equipment_Replacement

After the load is raised into the air and the fuel is discharged out of the back of the haul trailer into the truck receiving hopper a large plume of dust often launched into the air and then carried in the wind off the plant site. After the wood discharges out of the truck receiving hopper it is transferred via conveyor belt to a disc screen and hammer hog to be properly sized and then discharged onto the hog storage area.

Both Safety and Environmental regulations require that PM be reasonably controlled for worker safety, air quality and visibility. All emissions should be managed on-site.

The fuel yard is subject to a very corrosive environment due to the wet wood being in contact with the equipment. The years of rusting has caused failure to metal conduit and structural steel. The metal support structure of the truck receiving hoppers has rusted through to the point of being completely cracked through. Welded plates have been installed to affected areas on the truck receiving dumpers. Many of the electrical conduits are rusted through and need replacement.

The system is currently running at maximum capacity with fuel spilling over the edges of the conveyance system, the disc screen is not operating at the proper throughput as a significant amount of proper sized fuel is carried over the disc screen into the hammer hog. The over feeding of material into the hog creates excessive wear on the hammer hog grates and hammers.

With an average of 80 semi loads delivered each day and over 25 sawmills depending on the fuel yard at Kettle Falls to be in full operation there is tremendous pressure in keeping the system running. Area mills store the fuel purchased by Avista in storage bins and can only hold the waste wood for a few days and sometimes only hours before the backup of wood begins to cause production issues at the mill. When product flow out of the mill is not managed well suppliers may begin to look for other options to move their waste to more reliable markets. Another important detriment to not keeping fuel moving efficiently is that as more fuel inventory builds at the supplying mill, the resulting Moisture Content increases as well as the opportunity for contamination from rock and other "non-spec" materials. It is important to keep the KFGS fuel yard operating with minimal downtime to provide good service and quality control to the supplier's milling operations. It is critical to the reliability of both the KFGS plant and its supply chain.

In 2017 a team was assembled including the Thermal Operations and Maintenance Manager, Fuel Manager, Plant Manager, Thermal Engineering and plant staff. The team worked with outside engineering firm WSP to evaluate the fuel yard equipment and explore options. The team also traveled to two new biomass plants to gain knowledge of new equipment and process. This information along with the support of WSP allowed the team to evaluate a number of options.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Major drivers for this project were Asset Condition and Mandatory & Compliance. Installing the new fuel yard equipment with a higher capacity design and environmental dust control measures will be a benefit to the plant and neighbors. Moving truck through the yard quickly reduces trucking costs. This project will decrease truck turn time.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The plant experienced a fatality of a contract driver that would have been completely avoided if the truck dumpers were able to lift the current truck weights and lengths. A few years later another driver was injured on plant site attempting to manually offload his overloaded trailer when a bunch of fuel slid out of the trailer and buried the driver crushing his hip and knee. This project will make for a safer facility for our contractors.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Truck weight analyzer and the weighwiz system will be able to accurately capture the delivery with the new longer scales. Truck turntime will decrease as drivers will no longer need to lift tag axels, disconnect the truck and trailer or use one scale for inbound and outbound scaling.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

In 2017 a team was assembled including the Thermal Operations and Maintenance Manager, Fuel Manager, Plant Manager, Thermal Engineering and plant staff. The team worked with outside engineering firm WSP to evaluate the fuel yard equipment and explore options. WSP presented the Team a feasibility study with options to consider. That document is located in the project file.

KF_Fuel Yard Equipment_Replacement

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The team selected option #3 and in replacing the major equipment in a new layout. Below shows the four options, matrix score, CAPX and OPEX.

This feasibility study includes estimated CAPEX, OPEX and MTC, and discusses the pros and cons of the scenarios analyzed. The possibility of an increase in generation of 15 MW was considered when sizing the equipment. Some equipment drives may require upgrading, as such the equipment was sized for the increase.

Based on extensive in-person meetings with the Avista project team, four scenarios were examined to meet the requirements of the plant; results of the analysis for the scenarios are shown in the table below.

	System #1: Existing and Rebuilds	System #2: Existing Layout c/w new equip	System #3: New Layout c/w new equip	System #4: New System c/w Covered Building
Avista's Ranking Calculator by System	370.00	296.00	123.00	143.00
CAPEX (2017 $)	$4.2 M	$9.5 M	$21.6 M	$30.1 M
OPEX (average over 20 years, 2017 $)	$1,095,000	$1,121,000	$665,000	$998,000
MTC (average over 20 years, 2017 $)	$829,000	$782,000	$405,000	$432,000

2. PROPOSAL AND RECOMMENDED SOLUTION

The four options were discussed and doing nothing has been the approach for a number of years. Maintenance costs have increased with equipment failure to the live bottom gear boxes, dumper cylinders and lifting deck. Modifications are being made to equipment due to obsolete equipment is no longer available. This approach will see continued breakdown maintenance, reduction in fuel yard reliability and continued risks around safety and environmental litigation.

Option 1 includes major rebuild of the existing equipment. The truck dumpers would have mechanical and support rebuilt, some conveyors would be sped up to the maximum allowed throughput, hog and disc screen would be rebuilt, the power distribution, motor control centers and PLC's replaced, all the electrical hardware in the yard would be replaced. This option would not change the operations of the fuel handling system. Safety and environmental concerns would remain unchanged. The truck scaling issue would still remain. The work would create major disruptions to our suppliers as the work and repairs could not be done without interrupting delivery schedules for days and weeks at a time. Fuel would have to be diverted to other consumers with the risk of losing the contracts in the future.

Option 2 included replacing key equipment with one new scale, two dumpers, two conveyors, hog and screen in the existing location. This option would not address the congested truck route that currently exists with one scale. The fuel conveyor angle would remain the same and would not solve the sliding winter fuel issues experienced by the plant operations staff all winter long. This option would disrupt dilveries and cause major fuel disruptions to the sawmills and carriers under contract. Temporary truck dumpers would have to be installed and significant fuel curtailment and deverting would be required.

Recommendation is to pursue Option 3 that includes relocating new equipment to a different location in the fuel yard. This approach would allow the current system to operate while the new system is constructed and commissioned. The layout would reduce crossing traffic issues with the semi trucks. A new longer inbound and separate outbound scales would eliminate the scaling issue as sensors would not allow a driver to scale in unless the truck was positioned correctly on the scale. The two new truck dumpers would be larger in size which would allow the lifting of both the truck and the trailer. This would reduce truck turnaround time and eliminate the hazard identified in the driver fatality. The new dumpers would incorporate a dust containments systems to reduce fugitive dust during the offload. New conveyors would be larger to accommodate higher throughput. The higher capacity belt system would reduce laborious shoveling of spilled fuel. The incline of the new belts would reduce winter frozen fuel from sliding on the conveyor belts. The disc screen would be larger in size for better screening efficiency and reduce hog operation to only oversized material. The upgraded stack out fuel conveyor system would strategically move the fuel to three locations reducing Caterpillar dozer fuel consumption and yearly time base maintenance. A new control tower and power supply would eliminate the electrical deficiencies with the current system.

Option 4 is the same as option 3 with the addition of a covered fuel storage area. Covering the fuel could reduce moisture content during the winter months. Power Supply and Asset Management explored the additional cost benefit and this option did not make financial sense.

Option	Capital Cost	Start	Complete
Existing Rebuild and Minor Upgrades	$4,200,000	10/2020	6/2023
Existing Layout with New Equipment	$9,500,000	10/2020	6/2023
New Layout with New Equipment	$22,000,000	10/2020	6/2023
New Layout with New Equipment and Covered Yard	$30,100,000	10/2020	6/2023

KF_Fuel Yard Equipment_Replacement

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The Team worked with WSP and evaluated ever component of the fuel handling system. All of the current equipment was ranked using the GPSS project ranking matrix and the scores were used to determine what system would meet the criteria set for the project. Below is an example of the analysis that was done for every part of the fuel handing system.

Avista KFGS Woodyard Study — **Equipment Alternatives and Ranking Table**

WSP Ref #: 171-11373-00/185233A — Date: 10/19/2017

			Scope of Work Description & Avista Rating			
Item #	**Equipment Name**	**Wt**	**System #1: Existing**	**System #2: Existing Layout c/w new equip**	**System #3: New Layout c/w new equip**	**System #4: New System c/w Covered Building**
1	**Truck Scale(s)**		- maintenance	- new single scale and data recorder	- new dual scales and data recorder	- new dual scales and data recorder
	Personal or public safety	4	3	2	0	0
	Potential environmental issue	4	0	0	0	0
	Regulatory mandate	3	0	0	0	0
	On-going maintenance issue wt:3	3	2	0	0	0
	Decrease future operating costs	2	2	0	0	0
	Increase efficiency (revenues - power usage)	1	1	1	0	0
	Obsolete parts and equipment	1	0	0	0	0
	Risk of equipment failure	4	2	2	0	0
	Customer Value	3	2	1	0	0
	Sub-total		37	20	0	0

Reference key points from external documentation, list any addendums, attachments etc.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

The project will be a two year project with engineering, design and major equipment procurement in the first year followed by construction and commissioning the following year. The beakdown is a two year period with $12 million in 2019 and $10 million in 2020. (7/8/2021 *The project will run into 2022 with a possibility of 2023. The project originally requested 22 million over two years, CPG has only funded 20 million. When presenting the request I failed to load the project during the estimating process so AFUDC and Loadings were not added at the time of the request. These two issues have a 4 million shortfall in project funding. During construction the underground excavation process discovered unforeseen challenges with foundations and underground piping that resulted in re-engineering and changes. Cost and overruns form the phase one resulted in the Team drastically cutting scope to manage budget. Changes included re-routing the truck area, removing the enclosed processing building,* *repurposing some existing equipment, redesigning the layout to eliminate an entire conveyor and postponing replacing the final stackout conveyor.)*

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

This project will require some short outages that will be managed within the normal Spring outage for accommodate some conveyor transitions to the current process and power supply connections. There may be some curtailment needs with our contract mill to stop wood deliveries. This project will not cause any plant reliability issues with Power Supply.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The project will run into 2022 with a possibility of 2023. The project originally requested 22 million over two years, CPG has only funded 20 million. When presenting the request I failed to load the project during the estimating process so AFUDC and Loadings were not added at the time of the request. These two issues have a 4 million shortfall in project funding. During construction the underground excavation process discovered unforeseen challenges with foundations and underground piping that resulted in re-engineering and changes. Cost and overruns form the phase one resulted in the Team drastically cutting scope to manage budget. Changes included re-routing the truck area, removing the enclosed processing building, repurposing some existing equipment, redesigning the layout to eliminate an entire conveyor and postponing replacing the final stackout conveyor. The Team intentionally stopped work with the contractor Greenberry to reevaluate the costs. The installation was rebid to a number of contractors and a change was made with awarding the work to Knight Construction as a lower cost.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

(7/8/2021 *Update All of the underground work is complete minus two conveyor foundations that will be installed after the current truck dumpers are demolished. All major equipment is purchased and onsite minus the hammer hog and transition chute and the #3 stack out conveyor. The fueling building is procured and will be installed in September. The truck dumpers will be commissioned mid July. All the critical electrical equipment has been purchased. The project has two options for 2022 one being a complete project to the #3 conveyor and the other a hot feed option which could see some of the equipment in Q3 of 2022 either way. If the hot feed option is selected then the remaining equipment would become operational in 2023.)*

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Ketlle Falls is a renewable generating site and this project aligns with providing reliable renewable energy to our customers. This project will increase Safety and be good for the environment and neighbors.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

This project was subjected to a rigorous evaluation of each major piece of equipment and is documented in the WSP Feasibility Study. The project has worked closely with the Steering Committee that is represented by GPSS, Environmental and Power Supply. The project is being lead by GPSS Project Manager and the Team meets regularly to discuss scope, schedule and budget.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

GPSS Thermal Operations and Maintenance Manager

Environmental

Power Supply

Contracts and Supply Chain

Plant Staff

2.8.2 Identify any related Business Cases

KF 4160 V Station Service replacement (new request in 2022)

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Thomas Dempsey - GPSS Thermal Operations and Maint Mgr

Darrell Soyars – Environmental

Scott Reid – Power Supply

3.2 Provide and discuss the governance processes and people that will provide oversight

GPSS Core team will follow the Department Project Management protocol. There will be monthly Steering Committee meetings to discuess issues or concerns. Updates will be shared on an as needed basis between monthly status meetings.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Chage orders will follow Supply Chain contracting protocol based on financial signing authority.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Fuel Yard Equipment Replacement project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Greg Wiggins Date: 7/8/2021
Print Name: Greg Wiggins
Title: Plant Manager
Role: Business Case Owner

Signature: Andy Vickers Date: 7/9/2021
Print Name: Andy Vickers
Title: Director GPSS
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:

KF_Fuel Yard Equipment_Replacement

Role: Steering/Advisory Committee Review

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

KF_Fuel Yard Equipment Replacement

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2022), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This business case is for the replacement of equipment for receiving and processing fuel for use at the Kettle Falls Thermal Generating Station. This equipment no longer meets the needs of the facility as it has aged and standards around it have changed, such as larger deliveries the equipment is not sized for and more stringent environmental standards.

The plan, as filed in the Washington GRC, was for construction through 2022 into early 2023 with commissioning and transfer to plant (TTP) in April, 2023. However, in early 2022 the steering committee agreed to a new approach which allowed for the new equipment to be commissioned simultaneously while the original system was still operating. This shortened the commissioning schedule and allowed the major equipment to be transferred to plant earlier than expected.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This project was governed by a Steering Committee representing Power Supply, Environmental and Operations. The Steering Committee evaluated the options and supported the April 2022 request (attached) to the Capital Planning Group for additional funding of $2.5M to cover the expected remaining construction costs and earlier TTP. This additional funding was determined to be necessary to complete the construction and deliver a functional system to the plant. The Steering Committee voted to adjust the schedule and budget to move funds out of 2023 and into 2022.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

Early TTP of this project will reduce or delay major maintenance expenses on the aging equipment, which includes elimination of the 2023 rebuild of the primary disc screen, replacing belts on the two removed conveyors, repairing and/or replacing truck dumper drag chains, maintenance on the old hog, and potentially other maintenance items, for an estimated short-term savings of greater than $30,000. In addition, by bringing the system online earlier than scheduled, an estimated $225,000 in forecasted capital expense on AFUDC was saved and will be re-deployed to other projects in 2023.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

x Andy Wiggins 3/15/23

DIRECTOR SIGNATURE:

x Alexis Alexander 03/15/23

KF_Fuel Yard Equipment_Replacement

EXECUTIVE SUMMARY

The existing system does not allow the plant to operate consistently with safe best practices, environmental stewartship and production. The fuel handling equipment operates at or beyond its absolute limit. In the early 1980's Washington State increased the legal hauling weight and the trucking industry transitioned from 48' trailers to 53' to increase their payload. This change created a number of production and safety challenges for the plant operations and contractor support. The system does not meet current environmental regulations for visibility and particulate matter (PM) emissions for intermittent periods. Although the primary drivers for the project are safety, environmental, and reliability, we do expect a decrease in O&M. With all benefits included, Financial Planning and Analysis has concluded that this is a prudent project. The project will proceed over a two year period with $12 million in 2019 and $10 million in 2020. (7/8/2021 Update: *Project timeline has been extended and adjusted and the current plan will continue into 2021 with the underground utilities installed, major equipment purchased and truck dumpers commissioned. 2022 will be construction of conveyance, processing and control buildings and installation of the hog and disc screen*.) (8/29/2022 Update: Construction is on track for Transfer to Plant by the end of the year. Additional funds were requested mid-year in 2022 for an annual total of $11.1M, in addition to $20M spent prior to 2022 and $1M projected for 2023. Project total at completion is projected to be $32M.)

Replacing the major fuel handling equipment will create a safer system for employees and contractors as the new dumpers will be designed to lift current truck lengths and weights. The major equipment will be designed with covers and passive dust control utilizing new dumper technology and conveyance covers. (*7/8/2021 Update: Scope has been reduced to reduce project costs by changing the truck route, eliminating a pass through travel route, reduction of an enclosed processing building, eliminating a conveyor through a more compact layout, eliminating a new power supply from the distribution line near the plant site and delay of replacing the existing #3 fuel conveyor*)

This project will impact customers in service code Electric Direct jurisdiction Allocated North serving our electric customers in Washington and Idaho.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Greg Wiggins*	*Initial draft of original business case*	*05/01/2018*	
1.0	*Thomas Dempsey*	*Edit Draft / Executive Summary*	*07/03/2018*	*Added content*
1.1	*Greg Wiggins*	*Edit Approved Business Case to new Template*	*07/08/2021*	*New Template / Update major project changes Scope, Schedule and Budget*

KF_Fuel Yard Equipment_Replacement

1.2	*Greg Crossman*	*2022 update*	*08/29/2022*	*Updated with current status*

GENERAL INFORMATION

Requested Spend Amount	$32,000,000 through 2023 ($26.3M spent to date)
Requested Spend Time Period	*2 year (7/8/2021 Update project will be 5 year)*
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Greg Wiggins | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Execution *(7/8/2021 Update project is in execution phase)*
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

The major fuel yard equipment being considered for replacement includes the truck dumpers, fuel hog, truck scale, and conveyance systems.

Truck Scale - The truck scale is used to account for the quantity of fuel received from each truck delivery. The truck drivers scale in upon arrival to the site and the scale out after completing the unloading process.

Truck Dumpers - The truck dumper receives the delivered fuel by elevating the trailers. Fuel exits the rear of the trailer into a receiving housing.

Fuel Conveyors - Fuel conveyers move the fuel from the truck dumpers to a metal detection system, then to the fuel hog system and finally out to the fuel yard.

Hog and Disc Screen - The fuel hog is a device that clarifies and conditions the fuel so that it is the proper size required for optimum combustion.

1.1 What is the current or potential problem that is being addressed?

There are three key components that comprise the business problem presented by the current fuel yard.

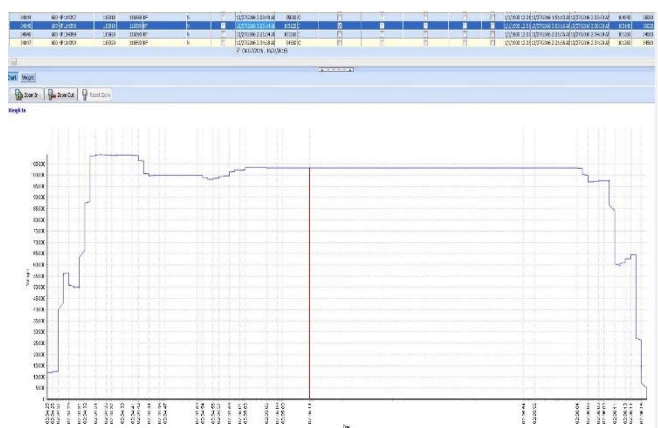
1. Safety
2. Environmental
3. Reliability

These three components are summarized as follows:

The Kettle Falls Generating Station is a biomass fueled power plant that processes on average 500,000 green tons of waste wood from area sawmills. The wood delivered to the facility is trucked in by contractors utilizing semi-trucks and chip trailer. On average the plant received 65-80 loads of fuel each day with surges to 100 deliveries in a 24 hour period.

The plant's original design was just prior to Washington State increasing the legal haul lengths and weights. All the equipment was designed for 48' trailers and the new law change in 1985 allowed drivers to haul with 53' trailers. When the drivers enter the facility the load is weighed on a State certified scale to determine amount of fuel being delivered. The longer trailers do not completely fit on the scale without the drivers lifting the tag axle on the trailer. The plant's delivery tracking system captures the gross weight of the truck and trailer into the 3Log financial interface application. Through this system vendors and suppliers are paid for their services. Due to the longer trailers and short scale drives can "cheat" the system by not positioning the load correctly on the scale. Each load is reviewed through the 3Log (TWA) Truck Weight Analyzer. When an infraction is found the surveillance video is reviewed and sent to the hauling company for reconciliation. Manual adjustments are made in the system to ensure proper payment to the supplier.

Truck was intentionally positioned short on the scale.



TWA show drivers manipulating the scale due to being overloaded.

The fuel is offloaded truck trailers into the receiving hoppers via a truck dumpers. The wood is then conveyed, screened and sized prior to being transferred out to the fuel inventory pile. The Fuel Equipment Operators then manage the fuel inventory utilizing D10 Cat dozers to stack out incoming fuel and stage inventory to be processed in the plant.

Due to the higher legal hauling limits in Washington the longer truck/trailer configurations require the truck drivers to unhitch the trailer from their trucks. This unhitching process not only increases truck turnaround time and increases hauling costs to plant, it adds a difficult step. Although not the primary factor, a contractor fatality in 2013 occurred while going through this step in the process. One driver was attempting to unhitch his trailer from the truck and was working with another driver to get the hitch pin released when the accident occurred.

After the load is raised into the air and the fuel is discharged out of the back of the haul trailer into the truck receiving hopper a large plume of dust often launched into the air and then carried in the wind off the plant site. After the wood discharges out of the truck receiving hopper it is transferred via conveyor belt to a disc screen and hammer hog to be properly sized and then discharged onto the hog storage area.

Both Safety and Environmental regulations require that PM be reasonably controlled for worker safety, air quality and visibility. All emissions should be managed on-site.

The fuel yard is subject to a very corrosive environment due to the wet wood being in contact with the equipment. The years of rusting has caused failure to metal conduit and structural steel. The metal support structure of the truck receiving hoppers has rusted through to the point of being completely cracked through. Welded plates have been installed to affected areas on the truck receiving dumpers. Many of the electrical conduits are rusted through and need replacement.

The system is currently running at maximum capacity with fuel spilling over the edges of the conveyance system, the disc screen is not operating at the proper throughput as a significant amount of proper sized fuel is carried over the disc screen into the hammer hog. The over feeding of material into the hog creates excessive wear on the hammer hog grates and hammers.

With an average of 80 semi loads delivered each day and over 25 sawmills depending on the fuel yard at Kettle Falls to be in full operation there is tremendous pressure in keeping the system running. Area mills store the fuel purchased by Avista in storage bins and can only hold the waste wood for a few days and sometimes only hours before the backup of wood begins to cause production issues at the mill. When product flow out of the mill is not managed well suppliers may begin to look for other options to move their waste to more reliable markets. Another important detriment to not keeping fuel moving efficiently is that as more fuel inventory builds at the supplying mill, the resulting Moisture Content increases as well as the opportunity for contamination from rock and other “non-spec” materials. It is important to keep the KFGS fuel yard operating with minimal downtime to provide good service and quality control to the supplier’s milling operations. It is critical to the reliability of both the KFGS plant and its supply chain.

In 2017 a team was assembled including the Thermal Operations and Maintenance Manager, Fuel Manager, Plant Manager, Thermal Engineering and plant staff. The team worked with outside engineering firm WSP to evaluate the fuel yard equipment and explore options. The team also traveled to two new biomass plants to gain knowledge of new equipment and process. This information along with the support of WSP allowed the team to evaluate a number of options.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Major drivers for this project were Asset Condition and Mandatory & Compliance. Installing the new fuel yard equipment with a higher capacity design and environmental dust control measures will be a benefit to the plant and neighbors. Moving truck through the yard quickly reduces trucking costs. This project will decrease truck turn time.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The plant experienced a fatality of a contract driver that would have been completely avoided if the truck dumpers were able to lift the current truck weights and lengths. A few years later another driver was injured on plant site attempting to manually offload his overloaded trailer when a bunch of fuel slid out of the trailer and buried the driver crushing his hip and knee. This project will make for a safer facility for our contractors.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Truck weight analyzer and the weighwiz system will be able to accurately capture the delivery with the new longer scales. Truck turntime will decrease as drivers will no longer need to lift tag axels, disconnect the truck and trailer or use one scale for inbound and outbound scaling.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

In 2017 a team was assembled including the Thermal Operations and Maintenance Manager, Fuel Manager, Plant Manager, Thermal Engineering and plant staff. The team worked with outside engineering firm WSP to evaluate the fuel yard equipment and explore options. WSP presented the Team a feasibility study with options to consider. That document is located in the project file.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The team selected option #3 and in replacing the major equipment in a new layout. Below shows the four options, matrix score, CAPX and OPEX.

This feasibility study includes estimated CAPEX, OPEX and MTC, and discusses the pros and cons of the scenarios analyzed. The possibility of an increase in generation of 15 MW was considered when sizing the equipment. Some equipment drives may require upgrading, as such the equipment was sized for the increase.

Based on extensive in-person meetings with the Avista project team, four scenarios were examined to meet the requirements of the plant; results of the analysis for the scenarios are shown in the table below.

	System #1: Existing and Rebuilds	System #2: Existing Layout c/w new equip	System #3: New Layout c/w new equip	System #4: New System c/w Covered Building
Avista's Ranking Calculator by System	370.00	296.00	123.00	143.00
CAPEX (2017 $)	$4.2 M	$9.5 M	$21.6 M	$30.1 M
OPEX (average over 20 years, 2017 $)	$1,095,000	$1,121,000	$665,000	$998,000
MTC (average over 20 years, 2017 $)	$829,000	$782,000	$405,000	$432,000

2. PROPOSAL AND RECOMMENDED SOLUTION

The four options were discussed and doing nothing has been the approach for a number of years. Maintenance costs have increased with equipment failure to the live bottom gear boxes, dumper cylinders and lifting deck. Modifications are being made to equipment due to obsolete equipment is no longer available. This approach will see continued breakdown maintenance, reduction in fuel yard reliability and continued risks around safety and environmental litigation.

Option 1 includes major rebuild of the existing equipment. The truck dumpers would have mechanical and support rebuilt, some conveyors would be sped up to the maximum allowed throughput, hog and disc screen would be rebuilt, the power distribution, motor control centers and PLC's replaced, all the electrical hardware in the yard would be replaced. This option would not change the operations of the fuel handling system. Safety and environmental concerns would remain unchanged. The truck scaling issue would still remain. The work would create major disruptions to our suppliers as the work and repairs could not be done without interrupting delivery schedules for days and weeks at a time. Fuel would have to be diverted to other consumers with the risk of losing the contracts in the future.

Option 2 included replacing key equipment with one new scale, two dumpers, two conveyors, hog and screen in the existing location. This option would not address the congested truck route that currently exists with one scale. The fuel conveyor angle would remain the same and would not solve the sliding winter fuel issues experienced by the plant operations staff all winter long. This option would disrupt dilveries and cause major fuel disruptions to the sawmills and carriers under contract. Temporary truck dumpers would have to be installed and significant fuel curtailment and deverting would be required.

Recommendation is to pursue Option 3 that includes relocating new equipment to a different location in the fuel yard. This approach would allow the current system to operate while the new system is constructed and commissioned. The layout would reduce crossing traffic issues with the semi trucks. A new longer inbound and separate outbound scales would eliminate the scaling issue as sensors would not allow a driver to scale in unless the truck was positioned correctly on the scale. The two new truck dumpers would be larger in size which would allow the lifting of both the truck and the trailer. This would reduce truck turnaround time and eliminate the hazard identified in the driver fatality. The new dumpers would incorporate a dust containments systems to reduce fugitive dust during the offload. New conveyors would be larger to accommodate higher throughput. The higher capacity belt system would reduce laborious shoveling of spilled fuel. The incline of the new belts would reduce winter frozen fuel from sliding on the conveyor belts. The disc screen would be larger in size for better screening efficiency and reduce hog operation to only oversized material. The upgraded stack out fuel conveyor system would strategically move the fuel to three locations reducing Caterpillar dozer fuel consumption and yearly time base maintenance. A new control tower and power supply would eliminate the electrical deficiencies with the current system.

Option 4 is the same as option 3 with the addition of a covered fuel storage area. Covering the fuel could reduce moisture content during the winter months. Power Supply and Asset Management explored the additional cost benefit and this option did not make financial sense.

Option	Capital Cost	Start	Complete
Existing Rebuild and Minor Upgrades	$4,200,000	10/2020	6/2023
Existing Layout with New Equipment	$9,500,000	10/2020	6/2023
New Layout with New Equipment	$22,000,000	10/2020	6/2023
New Layout with New Equipment and Covered Yard	$30,100,000	10/2020	6/2023

KF_Fuel Yard Equipment_Replacement

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The Team worked with WSP and evaluated ever component of the fuel handling system. All of the current equipment was ranked using the GPSS project ranking matrix and the scores were used to determine what system would meet the criteria set for the project. Below is an example of the analysis that was done for every part of the fuel handing system.

Avista KFGS Woodyard Study — **Equipment Alternatives and Ranking Table**

WSP Ref #: 171-11373-00/185233A — Date: 10/19/2017

			Scope of Work Description & Avista Rating			
Item #	**Equipment Name**	**Wt**	**System #1: Existing**	**System #2: Existing Layout c/w new equip**	**System #3: New Layout c/w new equip**	**System #4: New System c/w Covered Building**
1	**Truck Scale(s)**		- maintenance	- new single scale and data recorder	- new dual scales and data recorder	- new dual scales and data recorder
	Personal or public safety	4	3	2	0	0
	Potential environmental issue	4	0	0	0	0
	Regulatory mandate	3	0	0	0	0
	On-going maintenance issue wt:3	3	2	0	0	0
	Decrease future operating costs	2	2	0	0	0
	Increase efficiency (revenues - power usage)	1	1	1	0	0
	Obsolete parts and equipment	1	0	0	0	0
	Risk of equipment failure	4	2	2	0	0
	Customer Value	3	2	1	0	0
	Sub-total		37	20	0	0

Reference key points from external documentation, list any addendums, attachments etc.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

The project will be a two year project with engineering, design and major equipment procurement in the first year followed by construction and commissioning the following year. The beakdown is a two year period with $12 million in 2019 and $10 million in 2020. (7/8/2021 *The project will run into 2022 with a possibility of 2023. The project originally requested 22 million over two years, CPG has only funded 20 million. When presenting the request I failed to load the project during the estimating process so AFUDC and Loadings were not added at the time of the request. These two issues have a 4 million shortfall in project funding. During construction the underground excavation process discovered unforeseen challenges with foundations and underground piping that resulted in re-engineering and changes. Cost and overruns form the phase one resulted in the Team drastically cutting scope to manage budget. Changes included re-routing the truck area, removing the enclosed processing building,* *repurposing some existing equipment, redesigning the layout to eliminate an entire conveyor and postponing replacing the final stackout conveyor.) (8/29/2022 Update: The project spent $20M through the end of 2021. CPG originally approved $8.6M for 2022, however after forecasting remaining costs to complete the project, an additional $2.5M was requested and approved via Funds Change Request for a 2022 total of $11.1M. CPG also allocated $1.5M for 2023, however that has also been revised via FCR to $1M to include demolition, punchlist, and cleanup after Transfer to Plant occurs toward the end of 2022.)*

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

This project will require some short outages that will be managed within the normal Spring outage for accommodate some conveyor transitions to the current process and power supply connections. There may be some curtailment needs with our contract mill to stop wood deliveries. This project will not cause any plant reliability issues with Power Supply.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Alternatives considered are discussed at the beginning of Section 2. Each alternative came with risks and benefits, however replacing the equipment in a new location (Option 3) was determined to be the solution providing the best business value to Avista. At present (8/29/2022), contracts have been awarded and the project is approaching startup and commissioning, on track for Transfer to Plant by the end of the calendar year.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

(7/8/2021 *Update All of the underground work is complete minus two conveyor foundations that will be installed after the current truck dumpers are demolished. All major equipment is purchased and onsite minus the hammer hog and transition chute and the #3 stack out conveyor. The fueling building is procured and will be installed in September. The truck dumpers will be commissioned mid July. All the critical electrical equipment has been purchased. The project has two options for 2022 one being a complete project to the #3 conveyor and the other a hot feed option which could see some of the equipment in Q3 of 2022 either way. If the hot feed option is selected then the remaining equipment would become operational in 2023.) (8/29/2022 Update: Construction is significantly underway with startup and commissioning beginning in September 2022. Transfer to Plant is expected by the end of the year.)*

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Ketlle Falls is a renewable generating site and this project aligns with providing reliable renewable energy to our customers. This project will increase Safety and be good for the environment and neighbors.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

This project was subjected to a rigorous evaluation of each major piece of equipment and is documented in the WSP Feasibility Study. The project has worked closely with the Steering Committee that is represented by GPSS, Environmental and Power Supply. The project is being lead by GPSS Project Manager and the Team meets regularly to discuss scope, schedule and budget.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

GPSS Thermal Operations and Maintenance Manager

Environmental

Power Supply

Contracts and Supply Chain

Plant Staff

2.8.2 Identify any related Business Cases

KF 4160 V Station Service replacement (new request in 2022)

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Thomas Dempsey - GPSS Thermal Operations and Maint Mgr

Darrell Soyars – Environmental

Scott Reid – Power Supply

3.2 Provide and discuss the governance processes and people that will provide oversight

GPSS Core team will follow the Department Project Management protocol. There will be monthly Steering Committee meetings to discuess issues or concerns. Updates will be shared on an as needed basis between monthly status meetings.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Chage orders will follow Supply Chain contracting protocol based on financial signing authority.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Fuel Yard Equipment Replacement project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Greg Wiggins	Date:	8/29/2022
Print Name:	Greg Wiggins		
Title:	Plant Manager		
Role:	Business Case Owner		

Signature:		Date:	
Print Name:	Alexis Alexander		
Title:	Director GPSS		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Thomas Dempsey		
Title:	GPSS Thermal Ops and Maint Mgr		
Role:	Steering/Advisory Committee Review		

Kettle Falls Fuel Yard Equipment Replacement Project

1.0 CHANGE REQUEST #4 – 4/13/2022

Previous Requests	Requested	Approved
5-Year Plan	NA	$8,600,000

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
03-2022	$1,687,173	$8,600,000	+$2,500,000	$11,100,000

Type of Change	In-year Update
Primary Reason for Change	Revised Cost
Response needed by	4/29/2022

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

In 2021 the project underspent its CPG allocation and returned $475,000 in December. At that time contracting of Phase 2 work was just beginning so it was not possible to utilize the funds before year end, however the scope that may have been funded still remains to be completed for a functional project and therefore requires those funds. In addition, the progression over the course of the project through design iterations into early procurements and then into phased construction resulted in 2022 becoming a catch-all for any remaining scope, which has increased total cost for the year. Further, not unique to this project, but no less impactful are the marked increases in pricing for commodities and construction contractors. Both inflation and supply chain issues have contributed to significantly higher prices in materials, fuel, transportation, and labor, resulting in higher overall costs to prosecute and complete the project.

The requested amount includes a contingency of approximately 3% on the 2022 remaining cost. While there is fairly high cost confidence at this point, the remaining scope is split into several discrete contracts so if any gaps or essential changes are discovered it is likely Avista will be financially responsible and not the contractors.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

The existing Fuel Yard has been beyond its useful life for several years. In fact one of the critical components, the truck dumpers, have been undersized essentially since the plant came online in the 1980s due to a change at that time to hauling limits. The undersized dumpers present an ongoing safety hazard to plant personnel and truck drivers delivering fuel to the project site so transitioning to the new system is critical to the plant's continued operation. In addition, the new fuel yard equipment has been on site since last year. Continuing to allow it to sit stored and unused will both allow the warranties to expire prematurely, potentially even before the equipment is in service, and cause undue degradation due to being stored outdoors versus installed and in use as intended.

Kettle Falls Fuel Yard Equipment Replacement Project

1.1.3 Please reference analysis or information that support the problem and attach to this document.

The current budget forecast is available upon request and shows projected expenditures for the rest of the year in order to deliver a functional project.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

O&M costs may be increased by delaying installation further into the future since warranties will expire prematurely and necessary maintenance may be more extensive, and therefore more costly, due to prolonged storage.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The team is actively exploring cost-saving options to value engineer the remaining work. For example, there is work currently specified at an existing structure that would be beneficial but not necessarily required to deliver a functional project to the plant. The team is evaluating if eliminating (or delaying beyond 2022) items like this would be feasible and if it can be done without unanticipated follow-on consequences. Construction is currently underway so there will be limited opportunities to change the design, but the team is looking for them where possible.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The additional funds requested will allow the Kettle Falls Generating Station to operate more safely and more reliably. Continuing to operate on the existing equipment presents both a safety hazard to people at the plant and increases the risk that an unforeseen outage to fuel delivery will occur.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid given the nature of this change. This change simply reflects an increase in the cost to perform the specified work remaining to deliver the project this year, primarily due to work from previous years pushing into 2022, as well as historic levels of inflation and price increases for materials, commodities, and labor. While cost-saving options are being explored where possible as noted above, the current approved amount will nonetheless be insufficient to deliver the project this year.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Thomas Dempsey	BC Owner	Thomas C Dempsey Digitally signed by Thomas C Dempsey Date: 2022.04.14 07:48:23 -07'00'	
Alexis Alexander	BC Sponsor	Alexis Alexander Digitally signed by Alexis Alexander Date: 2022.04.14 21:22:45 -07'00'	
	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Land Mobile Radio and Real Time Communication Systems

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Land Mobile Radio & Real Time Communication Systems business case provides communication technology solutions that enable our gas and electric staff to communicate with each other in the field and office in real time in very remote locations where cellular service is not available. Mobile radio coverage is an essential safety requirement for field staff working throughout our territory to maintain safe and reliable electric and natural gas infrastructure.

This business case was expected to transfer-to-plant approximately $1M and ended up transferring around $2.1M, resulting in an underestimated transfer-to-plant amount of approximately $1.1M. This is a result of work that was planned to be completed in 2022 that shifted into 2023, with an increase in transfers-to-plant for 2023. The largest of these delays was the result of work not completed before access to the site was made difficult by the end of the construction season and snow the onset of winter. The work representing the transfer-to-plant that shifted from 2022 into 2023 is as follows.

- LMR Coverage Enhancements Stranger Mountain $1.76M

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. Please see the following Capital Planning Group change request documents that represent changes to the plan from the filed general rate case amount. Through prudent governance of this business case, capital funding that was not able to be spent this year (and ultimately transferred-to-plant), was released for other areas of the business to utilize. This business case underestimated approximately $1.1M in transfer-to-plant. This variance is due to the LMR Coverage Enhancements Stranger Mountain project delays that shifted $1.76M in transfer-to-plant from 2022 to 2023 and the release of funding of $550,000 for the below projects.

Release - LMR CR01	As project details are defined, including product purchases, professional services, and internal labor, costs for 2023 are lower than originally anticipated. Execution of project work in this business case can be adversely affected by construction seasons shortened by weather, limited resources for implementation, or supply chain issues. The below projects contributed to the release of funds: •LMR Pole Mounted Repeater – Planning could only complete one site this year, as contracted engineering labor was unavailable to complete the remaining two sites. •Real Time Control Radio System Refresh – This project was adversely affected by resources working on higher priority project work. •Network Control Station Refresh – This project was put on hold since it is dependent upon the completion of the Real Time Control Radio System Refresh project. •Tait Push to Talk Mobile App Implementation – This project was put on hold due to resources working on other higher priority projects. •LMR Coverage Enhancements – Site #3 (Cataldo) – This project is dependent on real estate easement provisioning.	($550,000)
		($550,000)

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

When endpoint devices break down it can result in the inability of an employee to access essential technology systems such as our meter data, customer billing and our mapping data. This can result in indirect productivity savings across all areas of the business. Savings related to avoiding these down time issues were not affected in 2023 and the indirect savings originally estimated are appropriate for 2023.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

DocuSigned by:

X Walter Roys

28978793A9C64D0...

DIRECTOR SIGNATURE:

DocuSigned by:

X Alexis Alexander

EA27BABA767F467...

Land Mobile Radio

1.0 CHANGE REQUEST #CR01 – 12.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
12-2023	*Revised Cost*	CR01	$2,570,000	-$550,000		

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
12-2023	Revised Cost	$100k-$10M		$2,570,000	$2,020,000

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

This change request does not impact 2024 or any out years.

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Land Mobile Radio

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Land Mobile Radio Business Case is projecting a release of $550,000 for unused funds based on current projects forecasted for 2023. As project details are defined, including product purchases, professional services, and internal labor, costs for 2023 are lower than originally anticipated. Execution of project work in this business case can be adversely affected by construction seasons shortened by weather, limited resources for implementation, or supply chain issues. Based on a review of the current in-flight project work for 2023, the business case can release $550,000 in funding. If this funding is not returned, it could result in needed work in other areas of the business being underfunded.

The below projects contributed to the release of funds:

- LMR Pole Mounted Repeater – Planning could only complete one site this year, as contracted engineering labor was unavailable to complete the remaining two sites.
- Real Time Control Radio System Refresh – This project was adversely affected by resources working on higher priority project work.
- Network Control Station Refresh – This project was put on hold since it is dependent upon the completion of the Real Time Control Radio System Refresh project.
- Tait Push to Talk Mobile App Implementation – This project was put on hold due to resources working on other higher priority projects.
- LMR Coverage Enhancements – Site #3 (Cataldo) – This project is dependent on real estate easement provisioning.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Walter Roys	BC Owner	DocuSigned by: Walter Roys 28978793A9C64D0...	Dec-19-2023 | 8:59 AM PST
Alexis Alexander	BC Sponsor	DocuSigned by: Alexis Alexander EA27BABA767F467...	Dec-19-2023 | 2:43 PM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Change Request Form

Project Name: LMR Coverage Enhancements Stranger Mt. Phase 2
Clarity Project ID: PR00015136
Acctg Project #: 09906617
Business Case Name: Land Mobile Radio & Real Time Communication Systems (LMRRTCS)
ER/BI: 5030-30P01
Risk or Issue ID: RSK00005633
Constraint(s): Schedule & Funding
Submit Date: 05/31/2023

1 Key Roles & Project Information

Project Sponsor(s):	Jim Corder	**Business Case Owner(s):**	Walter Roys
Program Manager:	Angela Wood	**Project Manager:**	Cody Flavel
Steering Committee Members:	Jim Corder, Walter Roys, Michael Busby, Kaitlyn Richardson, Karen Schuh	**Primary Product Owner:**	Michael Thompson
		Other Stakeholders:	Reuben Arts

2 Summary of Change(s)

Due to the location on the top of Stranger Mountain (also known as Stensgar Mtn), access to the site has increased difficulty in the winter. Based on safety risks to crews considering the high elevation and remote location of the work, along with the significant distance to transfer the equipment up and down a hill, and vehicles required for the move, the decision was made to complete the transfer of service from the existing location to the new lease area once the snow dissipates. Therefore, this change request reflects a shift in the project TTP from 9/1/2022 to 09/30/2023 and Forecasted Project Close Dates from 11/1/2022 to 11/30/2023. This timeline shift will provide greater ease of access and increased safety for the crews performing the work. Last year the shelter was under construction during the summer. The summer weather this year will allow for the technical work completion. For example, moving cabinets from the existing location to the new location.

Additionally, with the delays associated with winter access issues and crew safety concerns, additional AFUDC costs have incurred during this timeframe. Taking into consideration the length of this project and the roll-over of labor resources, increased budget in Labor and Professional Services is requested in addition to minor adjustment to Other and Product.

2.1 Business Impact

The business impact includes risks to crew safety if the work occurs during the winter when access to the site has increased difficulty, particularly considering the high elevation and remote location of the work, along with the significant distance to transfer the equipment up and down a hill, and vehicles required for the move.

Avista employees and partners will benefit by the increased radio coverage in the northern region previously not served by Avista's land mobile radio system. Avista customers will benefit by the greater ease with which Avista employees can communicate. A more robust, safe, and secure radio system will greatly aid in the dispatch of crews in day-to-day operations and in emergency situations and these greater communication capabilities will benefit all Avista stakeholders.

3 Scope Change Details

Use Cases	Existing Deliverables	Changes to Deliverables
1,2,3	The prioritization and selection of one new Avista communication site in the northern region to achieve desired radio coverage.	None
1,2,3	New site acquisition to allow for the build out of one new Communication Site.	None

1,2,3	Commercial power delivered to the new site location.	None
1,2,3	Road access to new site location including easements or other legal agreements.	None
1,2,3	The construction of a communication tower to specifications to ensure adequate signal propagation.	None
1,2,3	The construction of a communications shelter to house planned equipment.	None
1,2,3	The installation of a generator and backup power to Avista specifications.	None
1,2,3	The installation of a DC Plant in rack configuration adequate to power planned equipment.	None
1,2,3	A network backhaul solution that will deliver adequate capacity for all planned improvements.	None
1,2,3	A remote site monitoring solution that includes out of band access as well as site alarm configuration.	None
1,2,3	The installation of radio equipment at specification to achieve desired propagation.	None
1,2,3	Site commissioning for the new communication site.	None
1,2,3	Coverage verification testing for the new communication sites.	None
1,2,3	Technical and physical drawings completed for all work performed.	None
1,2,3	A completed Security Impact Assessment for all impacted systems.	None
1,2,3	Operational handoff including the integration of preventative maintenance into existing schedules.	None

3.1 Where Will Technology Be Deployed

Equipment will be deployed on top of Stranger Mountain (also known as Stensgar Mtn).

4 Schedule Change Details

Major Milestone Descriptions	Target Completion Dates (MM/YY)	
	Planned Date	**Revised Date**
Project Initiation – *Actual approval date*	12/20	n/a
Scope approval w/VROMs (Go / No-go decision point) – *Actual approval date*	03/20	n/a
ETER review and approval actual date – *Actual approval date*	07/22	n/a
PMP / Approval to Execute – *Actual approval date*	07/22	n/a
Transfer to Plant (TTP) / Go-Live – *Planned date*	09/22	9/23
Forecasted Close Date – *Planned date*	11/22	11/23

5 Compliance and Controls

Area	Required (Y/N)
Compliance Impact Assessment (contact: Jennifer Massey)	N
Business Continuity Plan/Business Impact Assessment (contact: Erin Swearingen) - *Always Required (excluding enhancement packages)*	Y
Reliability Compliance (NERC) (contact: Erin McClatchey)	N
SOX Business Controls Impact Assessment (contact: Krista Johnson)	N
SOX Application Pre and Post Implementation Assessment (contact: Molly Favor)	N
Security Impact Assessment (SIA) (contact: Shanna Pagniano) - *Always Required*	Y
TSA Directive Review (contact: Jennifer Truman)	N
PCI (Payment Card Industry) Compliance Assessment (contact: Molly Favor)	N
Network Impact Assessment (contact: Ignacio Chapa) - *Always Required*	Y

6 Funding Change Details

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Labor:	$335,506	$135,523	$471,029
Non-ET Labor:	$11,954	$392	$12,346
Product:	$583,250	$6,911	$590,161
Professional Services:	$427,274	$38,112	$465,386
Other:	$31,397	$1,163	$32,560
AFUDC:	$137,853	$119,894	$257,747
Total:	**$1,527,234**	**$301,995**	**$1,829,229**

6.1 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories**. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service, and removal and decommissioning of retired assets.

Accounting Asset Category	Installation *(107600)*		Removal *(108000)*	Total ($)
	Physical Product ($)	Labor and Other ($)	Labor and Other ($)	
Hardware (FERC Account 391)	$413,113	$867,351	$0	**$1,280,464**
Communications Equipment (FERC Account 397)	$177,044	$371,721	$0	**$548,765**
Software (FERC Account 303)	$0	$0	$0	**$0**
Estimated Total Capital Cost:	**$590,157**	**$1,239,072**	**$0**	**$1,829,229**

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Long Lake Stability Enhancement

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

During preliminary design efforts, it was determined that piezometer inputs would be beneficial to informing the final design for the Long Lake Stability project. Upon determination of such, a project was created within this business case to create a separate project number allowing us to install and Transfer to Plant piezometers well in advance of the completed project construction (anticipated for 2028). Since the project did not initially plan for any capitalization/transfer to plant of these early design efforts, this business case was not submitted in the initial rate filing (September 2021) thus there is a variance reflective of the total cost of the piezometer installation effort.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The piezometers were installed using available project budget and were not an overrun or a change to the planned spend or scope, rather a change to the type of expenditure resulting in the ability to capitalize and transfer to plant an interim component of the design. The recommendation to install these piezometers was made by the project design team comprised of design engineering leadership and consultant structural engineers.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

Offsets are not an applicable byproduct of this scope of work. There are no operating costs that will be remediated by the ultimate stability enhancements made to the dam and there are no additional labor efforts associated with the piezometers in the interim.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Michael Truex
Michael Truex (Feb 27, 2024 16:23 PST)

Michael Truex
Michael Truex (Feb 27, 2024 16:23 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 28, 2024 10:08 PST)

David Howell
David Howell (Feb 28, 2024 10:08 PST)

Long Lake Stability Enhancement

EXECUTIVE SUMMARY

PROJECT NEED: The major driver for this business case is regulatory. FERC (Federal Energy Regulatory Commission) requested analysis revealed that Long Lake dam does not meet the internal plane stability minimum safety factor during a PMF (probably maximum flood) event. Avista submitted a preliminary study to the FERC and is waiting for final design before sending the FERC the full scope of the project and timeline to address mitigation. Avista is also revising the Spokane River PMF and performing a site-specific seismic hazard assessment to fully understand the loadings at the facility. The PMF has been recently approved and approval of the seismic loads are anticipated by mid-2023. The results of the detailed 3D modeling of the facility are anticipated to reduce the necessary mitigation efforts to satisfy FERC stability criteria. The FERC expects Avista to develop a mitigation plan to address the stability issues once modeling is complete and therefore this project is mandatory. If this project does not move forward, Avista's relationship with the FERC will be heavily damaged and costly operational changes or even fines will result.

RECOMMENDED SOLUTION: The recommended solution will be heavily informed by the Engineering efforts dating back to 2016, however, recent discoveries have narrowed the remediation efforts to the following Alternatives listed below.

ALTERNATIVES CONSIDERED (as of 2023):
Up to 5 different construction items may be needed for Long Lake Dam based on the ongoing engineering efforts. The path forward includes additional engineering (PCA & FEA of the dam and left abutment), design, FERC approvals, and construction. The expected possible alternatives include:

- Waterstop installation for Long Lake Dam
- Spillway pier repair (strengthening/ the concrete added in 1918 and 1930)
- Spillway pier stabilization (anchoring and/or new deck)
- Left abutment rock wedge stabilization
- Intake dam stabilization (anchors)

ALTERNATIVES CONSIDERED:
A high-level construction feasibility study was conducted prior to embarking on the 3D Finite Element Modeling stage and was refined by a third-party industry expert in dam stability and anchoring, and heavy civil construction Engineering Solutions. It was estimated that the construction could be done in one year but more realistically should be done over two years

- Alternative 1: Initial Anchor Design, Two Season Construction schedule (initial estimate of $18.52M)
- Alternative 2: Initial Anchor Design, One Season Construction schedule (initial estimate of $18.65M)
- Alternative 3: New Design, Anchors, Drains and Grouting (initial estimate of $17.35M)

Long Lake Stability Enhancement

COST OF RECOMMENDED SOLUTION: Total project costs have an overall estimate at complete cost of $41.6M (2023 estimate).

ADDITIONAL INFO: Not completing the Stability Enhancement Project will place Avista out of compliance with our FERC License Requirements. FERC can require operational changes or additional, costly risk reduction measures, up to and including the loss of power generation at Long Lake. If work is not performed this has cost and operational repercussions which could affect our customers in terms of cost, reliability of energy, and reputational damage. performed this has cost and operational repercussions which could affect our customers in terms of cost, reliability of energy, and reputational damage.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	PJ Henscheid	Format existing BC into exec summary	7.6.20	
2.0	Michael Truex / PJ Henscheid	Completion of full BCJN document	7.31.20	
3.0	PJ Henscheid	Updated to 2022 template and modified budget to align with improved estimates	8.24.22	
4.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
5.0	Wendy Iris/Brandon Little/PJ Henscheid	Updated to reflect current state of project and engineering efforts – revealing some new remediation needs	5/10/2023	
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 1,600,000	0
2025	$ 1,400,000	0
2026	$ 1,000,000	0
2027	$ 12,500,000	$ 20,000,000
2028	$ 16,100,000	$ 21,000,000

Project Life Span	13 years (2016-2028)
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	PJ Henscheid | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Long Lake dam does not meet the internal plane stability minimum safety factor during a PMF event. Also, Avista believes a large portion of water seepage in the concrete is related to deteriorated water stops installed along the vertical construction joints during the original construction.

1.2 Discuss the major drivers of the business case

The major driver for this business case is Regulatory/ Mandatory & Compliance. Avista is subject to multiple Federal, State and Local environmental regulatory programs. Avista is required by FERC to maintain facilities for generation and public safety. The FERC license for Long Lake HED includes several operational requirements that depend on reliable operation of the generation units as well as the intakes and spill gates.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Not completing the Stability Enhancement Project will place Avista out of compliance with our FERC License Requirements. FERC can require operational changes or additional, costly risk reduction measures, up to and including the loss of power generation at Long Lake.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. Avista Strategic Goals

This project touches upon the value that Avista is trustworthy. Executing this project allows Avista to take care or our assets—assets that are vital to providing our cusomters with reliable energy, safely.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

See Section 2.2

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: ***A final recommendation is pending final engineering design.*** The recommended solution will be heavily informed by the Engineering efforts dating back to 2016, however, recent discoveries have narrowed the remediation efforts to the following Alternatives listed below. ALTERNATIVES CONSIDERED (2023): Up to 5 different construction items may be needed for Long Lake Dam based on the ongoing engineering efforts. The path forward includes additional engineering (Pier Condition Assessment & Finite Element Analysis of the dam and left abutment), design, FERC approvals, and construction. The expected possible alternatives include: Waterstop installation for Long Lake Dam Spillway pier repair (strengthening/ the concrete added in 1918 and 1930) Spillway pier stabilization (anchoring and/or new deck) Left abutment rock wedge stabilization Intake dam stabilization (anchors)

In Scope: A final recommendation is pending final engineering design.

Out of Scope: A final recommendation is pending final engineering design.

Assumptions: A final recommendation is pending final engineering design.

The above alternatives have recently been presented to the project team; however, there is still active engineering work going on to determine the 3D effects of the facility and the seismic requirements at the location. Dam Safety is monitoring movement, uplift pressures, and deflection of the intake and spillway dam. The project team recently completed (February 2023) boring and drilling and is completing laboratory testing to aid the assessment of the structural integrity of the concrete piers. Once those variables are determined, these alternatives will be re-evaluated, and the capital investment costs will be re-analyzed.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- Alden Report
- Avista's Dam Safety Surveillance Plans and Reports
- Finite Element Analysis

- The initial design work, value engineering, and constructability reviews, as well as industry studies, reports, and information gleaned from Avista's peer dam owners have all contributed to the development of the business case.
- Risk Cost calculation from GPSS Asset Management Group: Risk cost is the product of the Failure Rate, Potential Consequence of failure, and the Probability of experiencing the potential consequence in the event of a failure. This risk cost is associated with the probable dollar value associated with Avista's exposure risk of each component. This exposure risk includes the cost of anything that threatens the company, including costs associated with a probable failure of the components (potentially including replacement, refurbishment, or lost generation costs), safety risks associated with normal operation or replacement actions, and probable environmental risks associated with the asset, and at times other costs such as public perception risk mitigation activities. While the company may not be able to shelter itself from risk completely, there are ways it can help protect itself from the effects of business risk, primarily by adopting a risk management strategy as a part of the asset management program. Risk costs not only take account for the exposure risk for an asset but also the criticality (or importance of an asset) and its' current condition. Risk costs are somewhat analogous to insurance premiums. They represent an annual cost, but the year-to-year costs vary with the condition of the assets. If we total the risk costs for all of our assets for the next year, the company would need to have monies set aside for that year to cover the costs associated with the assets that fail that year.

$$\begin{aligned} &\mathit{Annual\ Risk\ Cost} \\ &= [\mathit{Probability\ of\ Failure\ (that\ year)}] \times [\mathit{Consequence}\ \$] \\ &\times [\mathit{Likelhood\ of\ actually\ experiencing\ that\ consequence}] \end{aligned}$$

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	N/A	$0	$0	$0	$0	$0

Since this project is driven by regulatory efforts there are no known offsets.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	N/A	$0	$0	$0	$0	$0

Since this project is driven by regulatory efforts there are no known offsets.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: A final recommendation is pending final engineering design. However, the initial design work considers some high level mitigation solutions, including adding post-tension anchors into bedrock, adding pressure relief drains, and adding mass concrete to the dam structure itself. These options, or a combination thereof, can bring the dams into FERC stability compliance.

The recommended solution will be heavily informed by the Engineering efforts dating back to 2016, however, recent discoveries have narrowed the remediation efforts to the following Alternatives listed below. ALTERNATIVES CONSIDERED (2023): Up to 5 different construction items may be needed for Long Lake Dam based on the ongoing engineering efforts. The path forward includes additional engineering (Pier Condition Assessment & Finite Element Analysis of the dam and left abutment), design, FERC approvals, and construction. The expected possible alternatives include: Waterstop installation for Long Lake Dam Spillway pier repair (strengthening/ the concrete added in 1918 and 1930) Spillway pier stabilization (anchoring and/or new deck) Left abutment rock wedge stabilization Intake dam stabilization (anchors)

The above alternatives have recently been presented to the project team; however, there is still active engineering work going on to determine the 3D effects of the facility and the seismic requirements at the location. Dam Safety is monitoring movement, uplift pressures, and deflection of the intake and spillway dam.

The project team recently completed (February 2023) boring and drilling and is completing laboratory testing to aid the assessment of the structural integrity of the concrete piers. Once those variables are determined, these alternatives will be re-evaluated, and the capital investment costs will be re-analyzed.

Alternative 1: Initial Anchor Design, Two Season Construction schedule; $18.52M

This alternative was based upon an initial engineering analysis and therefore required many anchors. It was not selected, with thoughts that a more detailed engineering model would require a reduced number of anchors.

Alternative 2: Initial Anchor Design, One Season Construction schedule; $18.65M

This alternative was based upon an initial engineering analysis and therefore required many anchors. The construction schedule was revised to be one season to attempt to provide savings. It was not selected, with thoughts that a more detailed engineering model would require a reduced number of anchors.

Alternative 3: New Design, Anchors, Drains and Grouting; $17.35M

The engineering efforts are still in process. But those efforts are revealing other stability issues that will need to be addressed. The number of anchors may decrease but there is a possibility that additional work is needed to stabilize the Piers, Spillway, Intake and left abutment. This alternative is not a complete solution therefore not selected.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Initial stability studies revealed that Long Lake dam does not meet FERC stability criteria during PMF and Post-Earthquake loading conditions. Success of the project requires design and delivery of stability measures to bring the spillway and intake dams into compliance with FERC stability requirements. Stability measures justified through a value engineering analysis, satisfying FERC factors of safety for stability, and properly constructed per plans and specification would be considered a success.

The initial design work considers some high-level mitigation solutions, including adding post-tension anchors into bedrock, adding pressure relief drains, and adding mass concrete to the dam structure itself. These options, or a combination thereof, can bring the dams into FERC stability compliance. No other solutions are known to exist for stabilizing the dam.

Finalizing the design parameters and establishing a more defined budget will be essential in the success of project delivery and capital budget forecasting. To assist in delivering the project on time and within our budget parameters, we will be looking for an alternative progressive project delivery method.

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known

- **Start Date:** 2016
- **End Date:** 2028

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/Governance Team

- Jacob Reidt – Sr Manager Project Delivery
- Greg Wiggins – Sr Manager of Hydro Ops & Maintenance
- Meghan Lunney – Spokane River License Manager

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Long Lake Stability Enhancement business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 11:06 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alexis Alexander EA27BABA767F467...	Date:	Aug-26-2023 | 1:34 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		
Signature:	NA	Date:	
Print Name:	NA; Alexis Alexander is on the steering committee for this project.		
Title:	NA		
Role:	Steering/Advisory Committee Review		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Metro 115kV Substation

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Metro 115kV Substation has served the urban core of downtown Spokane for 50 years. The result of this substation rebuild project will be a flexible and reliable station that fulfills needs in multiple operation divisions. This project was originally under the Substation – Substation Rebuilds (renamed Substation – Asset Condition) business case, however, due to its size and complexity, it is now its own business case (created and funded in 2023). Since this is a new business case, there were no Transfer to Plant (TTP) costs scheduled.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This Business Case was monitored through the year and reviewed at the Electrical Engineering Budget Committee meeting each month. As cost overruns were identified, a decision was made to request additional funds through the Capital Planning Group. Attached is the formal request for initial and additional funding.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

DocuSigned by:
X Brian Chain
C4012FF13CFC491...

DIRECTOR SIGNATURE:

DocuSigned by:
X Vern Malensky
06C4FF5AB09E40B...

Metro 115 kV Substation

EXECUTIVE SUMMARY

The Metro 115kV Substation serves the urban core of downtown Spokane and has done so reliably for almost 50 years. Customer outages in this area are counted in terms of "minutes per decade", which has enabled our customers to implement and sustain a dense population of both commercial and residential interests, in a zero-lot line environment. The high reliability of the Spokane urban core comes about through the Metro Substation being partnered with the Post Street Substation to provide full redundancy to the downtown core. This strategy is typical for most large cities. The Metro Substation typically powers half of downtown Spokane, including the Historic Davenport Hotel, Washington Trust, Century Link, and Wells Fargo buildings among many others.

Our customers' trust in our reliable service that depends on this station, with components that are approaching the end of life, equipment that no longer meets present safety standards, and a unique existing site that imposes severe operational constraints. The existing transformers are 40+ years old, are unique and do not have spares, and use of the mobile transformer is not an option at Metro. These constraints threaten to create significant and extended customer outages in the event of major equipment failure for a significant portion of the downtown area. This project will address both the equipment and site issues in the most efficient and affordable way possible, based on the alternatives and risk analysis performed for this substation and detailed further in this document.

The result of this project will be a flexible and reliable station that fulfills needs in multiple operating divisions. The new substation will provide safer equipment, necessary redundancy, increased capacity, and a design that enables a longer station lifespan where individual pieces of equipment can be safely serviced. The design enables a longer station lifespan where individual pieces of equipment can be safely serviced and upgraded without prohibitive site/outage constraints. Additionally, the new substation would include two additional distribution feeders that will provide needed capacity and a redundant path for the hospital district and lower South Hill. A rebuilt Metro Substation will provide the reliability that our customers expect.

The total project cost is estimated at $73 Million. The selected option for the Metro 115kV Substation rebuild includes four 115kV lines, ring bus configuration with 6 breakers, two 30 MVA power transformers, 9 network feeders and 2 distribution feeders, 8 air core reactors with enclosures, and switchgear in its own enclosure. Also included in the substation cost is an architectural wall enclosure to provide security around the site, an underground cable vault for the large amount of network cables, a control and battery enclosure to house the control panels, and multiple underground duct banks that provide pathways in/out of the site for distribution, network, and transmission. The location of the new Metro substation in the City's downtown core requires the surrounding wall enclosure to adhere to a design review and permitting process that also includes architectural, landscaping, and other requirements to meet the downtown aesthetic. The smaller footprint of this site requires unique layouts and designs to accommodate all of the structures and equipment that are needed. Substantial cost increases in equipment and materials in the past few years have impacted the overall project budget and long-lead time equipment has had a negative impact on the timeline resulting in a longer construction period as well.

The risks associated with the existing Metro substation are significant and could include extended outages for half of the downtown area that is fed via Metro and Post St. The mobile substation is not an option at this location to stand up the site and keep the downtown area energized due to space constraints and technical incompatibilities. Beyond a temporary tie-line solution in the event of a transformer outage, there is no other option to maintain critical service to our downtown customers. Safety risks include significant fire risks to adjacent structures and occupants that are within 50 feet of the oil-filled equipment. Additionally, the switchgear which is not arc-flash rated puts personnel at risk as they must be inside the front of the cubicle to manually switch it. The risks of not moving forward with the new site and substation include the latter but also the negative public impact of not being able to provide power to the heart of the City for an undetermined amount of time. Due to the long lead times of major equipment (3 years for transformers) and the length of time to construct such a large and unique substation, the cost of the project is substantial. The longer the project takes to start and complete construction and energize, the higher the overall project cost, and there is an increase in the potential risk of older equipment failure.

The Metro rebuild project was scoped in 2020 and a Project Charter was initiated and approved in 2021. This effort included analysis and assessments of operational risks and challenges, mitigation options and costs for multiple rebuild, brownfield, and greenfield scenarios, and project estimation and milestones. These documents were developed by engineering teams, reviewed and approved by engineering managers and the Director. Continued monitoring and controlling, and reporting of the project scope, schedule and budget occur on a monthly basis with the department managers and Director. Any proposed changes to the project are managed and tracked through the change management process.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Karen Kusel/ Crystal Holmes*	*Final Draft of Business Case*	*3/1/2023*
BCRT	*Steve Carrozzo.*	*Has been reviewed by BCRT and meets necessary requirements* DS SC	May-09-2023 | 3:08 PM PD

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2023	$13,255,000	$0
2024	$19,500,000	$6,000,000 (CIRCUIT BREAKERS/WALL CONSTRUCTION)
2025	$14,100,000	$3,200,000 (AUTO TRANSFORMERS RECEIVED)
2026	$11,800,000	$55,800,000 (SUBSTATION CONSTRUCTION COMPLEX)
2027	$6,500,000	$6,000,000 (COMMUNICATION/SECURITY COMPLETE)
2028	$3,500,000	$2,000,000 (FINAL CHARGES)

Note: $4.5M has been funded for this project out of Substation Rebuilds Business Case for the period of 2020 to 2022. This brings the estimated total cost of the project to $73,000,000.

Project Life Span	*5 Years*
Requesting Organization/Department	Substation Engineering/M08
Business Case Owner | Sponsor	Glenn Madden | Vern Malensky
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

There are several Transmission, Distribution, and Substation issues at the current Metro 115kV Substation that are detailed below:

Transmission Related Issues

- Metro-Post St MTR-PST and Third & Hatch-Post St 3HT-PST Transmission Line Cables in Shared Duct Line/Manholes (3HT: Third & Hatch, PST: Post Street)
    - Issue: Between Post Street and Metro substations the latter being where the Third & Hatch-Post St 3HT-PST line transitions to underground cable) the two 115 kV lines share the same duct bank and ~10 manholes/splice vaults. The cables are exposed in this area to a double circuit failure due to single circuit problems (e.g., splice failure, cable fault, manhole fire).
    - Risk: The shared duct bank path is susceptible to a single cause of failure (e.g., dig-in) that affects both lines, similar to a double circuit 115 kV overhead design. Outage work affects both lines in the same way.

Metro 115 kV Substation

- Tunnel Design Causes Transmission Outages for Unrelated Work
  - Issue: Immediately south of the existing Metro Substation, in the Steam Plant alley, is a ~100' long "tunnel" that contains many types of cable including the 115 kV 3HT-PST Third & Hatch-Post St line racked in an open configuration on the tunnel walls. Other cables are various Avista and joint use communications cables, secondary cabling that is part of the Downtown Network and 13 kV Metro-Post St MTR-PST tie line cabling – 6 1500 kCM copper EPR cables, critical to backup operation of Downtown in the event of an equipment failure at either Metro or Post Street. Safe work practices from the industry are in use at Avista; these dictate that crews and engineers are not able to enter the tunnel (or any 115 kV underground facility) with the 115 kV energized. This requirement has led to the need to take the 115 kV transmission out of service, making the Bulk Electrical System (BES) less reliable for unrelated work.
  - Risk: The many shared uses of the Metro tunnel drive outages on the 115 kV 3HT-PST line that pose operational challenges and lessen the overall reliability of the Bulk Electric System.

- 115 kV Line Outages Required for Other Various Unrelated Work
  - Issue: Metro-Sunset 115 kV MTR-SUN transmission line exits the station and goes over specialized structures on top of the Steam Plant building.

    With the recent Steam Plant restaurant modifications/upgrades, kitchen vent fan(s) have been installed underneath this line and it is assumed we will need some sort of on-going future maintenance, which will require an outage to this circuit.

    Given that Steam Plant workers and maintenance crews are not familiar with the procedures required by WECC and NERC with regard to the BES, often outages to this line are requested with only 1-2 weeks of planned Steam Plant work. Avista's standard requires at least 21 days of notice for non-emergency outages.

    Due to the limited conductor clearance to the Steam Plant roof, there is a fence installed prohibiting access underneath this line. Controlling who has access is ongoing; non-qualified personnel have had access.

    Due to clearances, maintenance work to the exterior of adjacent buildings requires a safety watch and/or line outage. This is namely the building south of the OH section of PST-3HT at Metro.

    Double 115 kV line outages are required for almost all vault inspection/maintenance work of underground sections of both PST-3HT and MTR-PST. There are around ten transmission vaults that are shared between these two lines, mostly on Lincoln, between Post St and Metro. One way we have been operating around these conditions is by taking line outages at night for O&M work to be performed on overtime. Double line outages during the night are 2 to 2.5 times the cost of single line outages that can be performed during the day. This is due to the doubled labor cost per hour plus the need to have multiple crews and additional switchmen for the duration of the outage for multiple switching operations throughout the night.

  - Risk: Unrelated non-utility work causes outages on the 115 kV 3HT-PST line that pose operational challenges and lessen the overall reliability of the BES. Non-qualified workers have possible access to transmission line areas that do not have compliant NESC clearances.

- Nearby Overhead Transmission Lines – General Risk Assessment
  - Issues: The Metro-Sunset transmission MTR-SUN line was built in 1976 (47 years old) and north of I-90 there are four original structures (excluding the lattice steel structures on the Steam Plant roof – a building that Avista no longer owns)
    - The structures are along Lincoln St., which is one of the busiest north-south thoroughfares in Spokane. Several of these structures are on the corners of streets and alleys, putting them in prime locations for vehicle impacts.
    - The two tangent structures are class #3 wood poles, and do not meet NESC code with regards to strength requirements.
    - The pole on the corner of Steam Plant Alley is guyed in two locations. One guy is across Lincoln St. and is secured into the side of a brick building, and the other is guyed to the north, approximately 175' over the entrance to the Steam Plant, into a BNSF railroad trestle.
    - Current structures in the vicinity, including steel lattice structures, would not be suitable for a conductor upgrade to 795 ACSS, a higher capacity and current Avista standard conductor than existing, due to the existing structures not meeting NESC strength requirements.
    - Avista no longer owns this building so any access for inspections or maintenance by Avista must be coordinated with the current owners.
    - Due to the Lattice Steel Structure on the roof of the Steam Plant, there have been many necessary outages at the request of the owners to complete work and maintenance on the building. These include roof repair and maintenance, restaurant cooking vents install and servicing, air conditioning repairs and maintenance, and other structural maintenance.

    The overhead section of the Post St-Third and Hatch PST-3HT transmission line was built in 1987 (36 years old) and consists of three self-supporting steel structures and one wood structure, north of I-90.
    - The current configuration for transitioning from OH to UG at Metro does not lend itself well to a mobile sub installation if one was required for an extended time to make repairs at the current location
    - Clearance to the building south of Metro does not allow for exterior maintenance without an outage.
    - A large steel pole in the middle of the sidewalk along Post St, approximately 6 inches from the curb
  - Risk: Various out of date and non-standard transmission structures provide an increased potential for failure (car-hit poles, structural failure, corrosion, guy anchor failures or breaks). This could result in line faults, reduced reliability to the BES, and public safety hazards. Approximately 1-2 poles per year are hit/damaged in the downtown area.

- 115 kV Source Reliability (Recent Transmission Trip)
  - Issue: Transmission service to this station is redundant, but compared to other two-line stations and has had issues in the past with one side being underground and the other being overhead. For example, in 2018, a line tripped in the area, when a contractor dug up a guy wire which caused the wire to snap, resulting in the 115 kV Metro-Sunset 115 kV transmission MTR-SUN line and College & Walnut Feeder 12F4 (an overhead radial feeder in the area) to fault together.

    Both the 115 kV line and the College & Walnut feeder tripped out. The other source to Metro, the 115 kV Metro-Post St line, also tripped. Due to the lack of event recording equipment (old microprocessor relays) at Metro, the line could not be closed back to service and resulted in an extended outage. The lack of necessary information to determine what had occurred eliminated any confidence to re-energize.

    With both 115kV source lines tripped, Metro was momentarily without a source for half of Downtown. The relaying for the underground cable line between Metro and Post St does not allow reclosing, so this line stayed out of service. Metro at this point was a radial feed.

Fortunately, the line held once energized. Had the line needed to be repaired, or replaced, there would have been a substantial delay as Avista does not stock the parts, nor do we have the expertise in-house to do the work. While Metro was solely sourced by one 115kV line for about a week and a half, it could have been months, if repairs had been necessary. Note that the replacement of the oil-filled cabling with newer cross-linked polyethylene (XLPE) cabling does not change the fact that our most experienced in-house distribution cablemen do not have the training, experience, or equipment necessary to install transmission splices, even on XLPE. We would have to bring in external contractor resources and also find replacement cables that are significant long lead time materials.

- Risk: Single transmission line trips can, and have cascaded, causing a full Metro Substation outage. Cable transmission line trips cannot be repaired in-house and leave Metro susceptible to an extended sustained outage for an N-1 trip during the subsequent repair time, could extend to months. Having two transmission lines (sources) creates redundancy which reduces this risk significantly

Distribution Related Issues

- <u>Racking Breakers for Feeder Outages</u>
  - Issue: The switchgear at Metro Substation is some of the most heavily utilized on the system, from a feeder outage standpoint. This is because, due to the secondary network, it is inconsequential to customers for a feeder to be out of service. All primary conductors are underground cabling, which cannot be worked on while energized. Therefore, in the Downtown Network, Hot Line Holds are not used at all. Instead, if any work is necessary on the feeder, the feeder is completely taken out of service. This results in more planned switchgear breaker operations as well as more instances of breakers being racked in and out, as compared to any other distribution station on the system, except for Post Street, the other Downtown Network substation.

    Remote racking is available at Post Street, but not at Metro. Instead, the older switchgear is either jacked into place using a portable jacking motor, or in some cases, ratcheted horizontally into the energized 13 kV bus, manually. In order to do either requires a cableman to be physically inside the front of the switchgear cubicle.

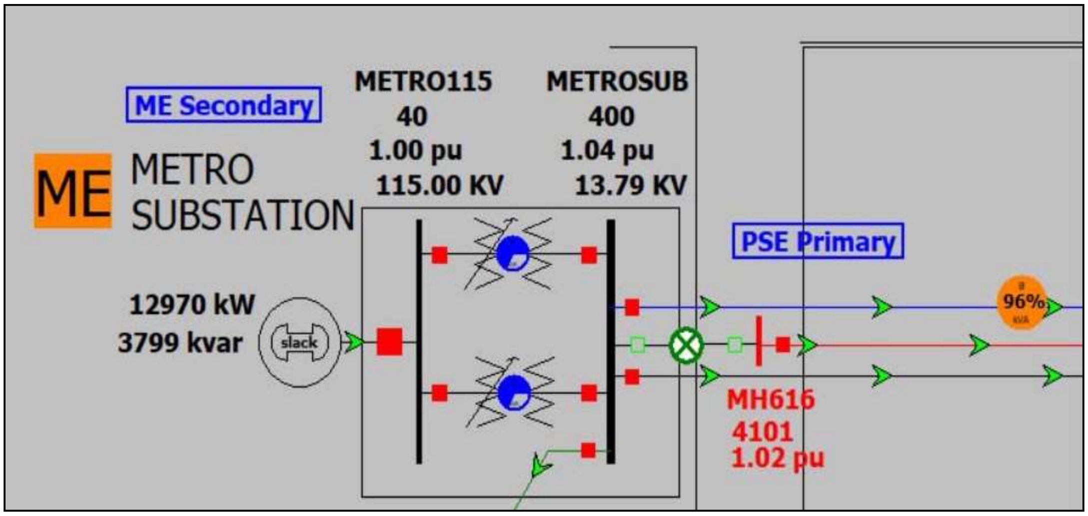
    While this operation is safe assuming everything goes correctly, it is not necessarily a design that is a good idea to “run to failure” as many failure scenarios involve severe employee injury or death due to arc flash. When Metro’s switchgear was procured, arc flash was not an industry-recognized concern.

  - Risk: Arc flash during racking operations will have severe consequences to cablemen who, by design, are directly in the line of fire.

- <u>Three Metro East Feeder Exits Need Upgraded for Thermal Reasons</u>
  - Issue: The present Metro East feeder exit cables all show at or over their capacity limits in Powerworld, a power flow system modeling software, under a contingency feeder trip analysis for both summer and winter loading.

    The Powerworld modeling provides data in the figure below. The worst cable capacity limits is Feeder #13636, which peaks at around 96%. Feeder #13637 is around 93%. Feeder #13638 lags and is “only” hitting about 87% but should be upgraded at the same time. Typically, over 80% is the threshold for starting to look at options to mitigate thermal issues and this site is obviously overdue.

Metro 115 kV Substation



- Risk: Failure of a feeder exit cable due to being run over capacity would result in an outage to a quarter of downtown. Cable overloads occur under contingency (when one of the other feeders to that quadrant are already out of service) so the second feeder trip triggers the Automatic Feeder Reduction (AFR) scheme which dumps the remaining feeder in the network in order to prevent further cascading failure in both the primary and secondary.

  Cable replacement and commissioning would take days to weeks depending on duct bank damage and whether the old cable was able to be removed. During that time the outage would continue as no options to backfeed primary exist within the Downtown Network.

- Lower South Hill Radial Feeder Reliability
  - Issue: The existing feeders that serve the lower south hill and the hospital district have experienced several extended outages. These feeders have exposure due to both length (College & Walnut 12F4 for example) and other special circumstances (transmission underbuilds, river crossings). Between 2018-2020, there were at least 2 to 3 outages on the College & Walnut 12F4 feeder that directly impacted the MultiCare Deaconess Hospital requiring them to go on backup generators. When on backup generators, they cannot perform any new surgeries.

  - Risk: Multiple recent outages in this area have caused many customer issues including cancellation of surgeries at Deaconess. This is a significant public risk, and the hospitals are critical customers. Work arounds in the past have included reconfiguring the feeders to take on the hospital load but this raises the load on the entire system and depending upon the season (hot or cold conditions/loads) it may be difficult or not possible to resolve.

Substation Related Issues

- Transformer/Low Side Fault Clearing
  - Issue: The existing Metro substation is presently only one of three stations on Avista's entire system that requires a 115 kV bus trip in order to clear a transformer or transformer low-side fault. Due to the lack of circuit switchers and the lack of space to add them. Which in turn is due to the station being built on a site that is entirely too small for the intended purposes. The existing scheme will dump the 115 kV bus using the transmission breakers to both Sunset and Post St transmission lines. With the bus and the southern half of Downtown de-energized, an air switch must be opened, which is supposed to be done automatically. However, it should be noted that these transformer

disconnect switches have rarely been maintained due to their electrical location; operational success under real conditions is not guaranteed and has proven to be an issue with other 115 kV transformer disconnect switches.

- Risk: If the air switches operate properly and automatically, then the load in the station is restored after only a momentary outage to half of Downtown. If they do not operate, then the outage has the potential to grow longer while a crew is called to the site in order to force the switch open

- <u>Fire Threat to Nearby Buildings</u>
  - Issue: Part of the switchgear at Metro is inside an alcove/garage underneath a section of the Steam Plant building to the west of the station. Avista no longer owns the Steam Plant. The Steam Plant is constructed of brick and steel with no added fireproofing. Required distancing between oil-filled equipment and a “possibly-manned” panel house in any of our stations is 50 feet, per IEEE 979. This is based on industry standards. When oil-filled equipment must be closer to panel houses than 50 feet, a firewall is required to be placed in the gap. There is no firewall, nor space to install one.

  - Risk: While the panel house at Metro was constructed within 50 feet of an oil filled 115 kV circuit breaker, the larger concern is that both transformers and both 115 kV circuit breakers (oil-filled) are within 40 feet of the Steam Plant building itself. Again, there is no fireproofing. The Washington Trust Data Building to the south is also only ~30 feet away. In the event of a failure to trip of any protective functionality inside the station, there is a significant risk of a catastrophic commercial building fire potentially putting property and lives in danger.

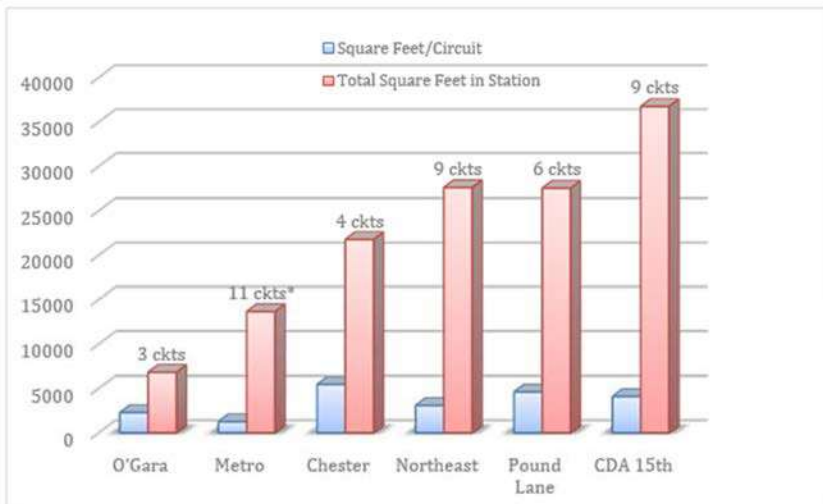
- <u>Batteries at the Existing Station are Undersized</u>
  - Issue: Batteries at the existing Metro are undersized given both the importance of the station (transmission breakers, six feeders of urban load) and the amount of equipment in the station. The station’s batteries are presently sized at 100 amp-hours (Ah). Stations), 48V DC and would only last a few hours. A 125V DC system is now the standard for transmission substations, providing 8-12 hours of backup per IEEE 485. Only 4 Avista substations have smaller batteries than Metro.

  - Risk: Batteries that are too small do not become an issue until a very critical moment (such as an extended station service outage or battery charger failure). Avista has been lucky to avoid a severe consequence in these scenarios, as can be experienced if a battery runs down in such a situation. Loss of battery backup results in a station service failure, loss of battery charger, breakers cannot trip or close on their own, and the station loses operability. System Operations is well aware of the criticality of station batteries.

    The worst-case scenario at Metro could be a failed charger with a missed alarm in System Operations as there is no battery voltage indication to SCADA at Metro, due primarily to the lack of microprocessor relaying and modern SCADA at Metro. Without this indication to start an immediate crew callout, the undersized battery would run down very quickly (within hours, not days) and limit the amount of time for the missed alarm to be caught.

    Note also, if a feeder or transmission breaker trip had been required during this time, the battery is unlikely to support the trip, which would result in the breaker failing to operate. In turn this could create the same kind of catastrophic effect that Grant County Public Utility District (GCPUD) saw in their Ephrata Substation fire, after the battery was unavailable to support a DC-powered breaker trip. The difference at Metro is that the smaller site, and lack of built-in fire protection for surrounding buildings and railroad, would threaten much larger consequences than just a “simple” substation fire (refer to Section 3.2).

- <u>Size of Existing Site is Insufficient</u>
  - Issue: The chart below shows a comparison of stations by a metric of “square feet per circuit”. Circuit in this case means either a transmission line terminating on a breaker, a distribution line, or built-in space for a future distribution line. Substation Engineering recommended several of the known “small” stations to compare Metro against. These included other similar stations with 115 kV breakers and/or switchgear, as well as a “tiny” station (O’Gara).



*Metro’s circuit (ckt) count does not take into account the 3HT-PST line, which transitions to underground within the existing Metro site.

  - Risk: This metric does not necessarily speak to the specific challenges faced at the existing site, but it does provide context generally as to why Metro is unique, and why it seems to present so many of these specific challenges.

    Note that “size per circuit” was not chosen as a metric simply because of the results it produced. If you compare, for example, the simple overall square footage of the existing Metro site to every other transmission station on Avista’s system, it is the second smallest at ~12,000 square feet despite serving significantly more load.

    It could also be noted that many of the stations that face significant space challenges inside the fence have mitigating factors that allow emergency operations to take place. For example, there typically options to install the mobile substation, replace 115 kV breakers, or crane in a transformer, but with the challenges at Metro due to both the surrounding environment and the equipment inside, these mitigations are not possible.

- <u>AFR Relaying Not Controllable by Feeder</u>
  - Issue: The unique secondary network that is fed from the Downtown Network feeders out of the existing Metro Substation has associated unique relaying – an Automatic Feeder Reduction or AFR scheme. AFR is intended to protect both the primary and secondary cabling in the Downtown Network from overloads in the event of more than one feeder being out of service.

    Feeders can be “out of service” in one of two ways: the primary breaker can be opened in the substation, or all network protectors downstream can be opened. As part of a normal primary clearance switching order, both situations must occur.

Metro 115 kV Substation

The AFR scheme is set up such that, if the primary breaker is open, then the relaying is automatically aware of the inability of that particular feeder to serve load (leaving the remaining feeders in that network as the sole providers of energy). However, unlike at Post Street, the AFR cannot be manually indicated to, in the event that network protectors downstream are open and not serving load.

- Risk: Metro's AFR configuration means that, at least once during every switching order, there are moments to sometimes hours (depending on needs of the order and crew availability) when tens of thousands of feet of cabling is exposed to a cascading overload event, if a second feeder is tripped for a fault. There are around 20 of these orders performed out of Metro every year.

- The "Pigeon Problem"
  - Issue: The Metro Substation is in a location that lends to having a lot of pigeons around. The pigeons defecate all over the substation.
  - Risk: This is not only a health hazard for our personnel but an electrical hazard as well. The droppings can cause unplanned outages due to insulator flashovers. To clean the station there has to be an entire 115 kV bus outage, which is extremely difficult to schedule.

- 115 kV PT Issues
  - Issue: On 4/2/2020, it was identified that the B phase 115 kV Bus PT was leaking. The serviceman tried to use the oil level gauge to determine the oil level, which would have helped with determining the urgency behind the replacement. Unfortunately, the gauge was not legible. That is not uncommon for old equipment. The PT's were manufactured in 1976.
  - Risk: The failure mode for PT's is quite destructive and has led to flying glass and oil fires. To replace the PT's, there has to be a whole 115 kV Bus outage, which is extremely difficult to schedule. The outage interrupts the continuity of the 115 kV path from Third & Hatch to Sunset. It also requires two simultaneous transformer outages at Metro. At any other site this would be a mandatory mobile transformer installation due to the reduction in distribution reliability in the area but is not possible at Metro.

- Recent LTC Issues Found
  - Issue: In May of 2018, Avista crews conducted routine transformer testing on both Transformer #1 and Transformer #2. The crew found an issue with Transformer #2 Load Tap Changer (LTC). They found that when the LTC is tapped in the lower direction, the tap changer may not complete a full operation.
  - Risk: Failure of an LTC would require the connected transformer to be taken out of service until fixed or replaced. This would result in an increasing load on remaining feeders and increased potential for negative cascading effect on the system.

- Avista Does Not Carry Spare LTC or Throat-connected Transformers
  - Issue: The repair on Transformer #2 LTC brought up the concern about not having a spare transformer with an LTC.
  - Risk: Installing a transformer without an LTC would cause the distribution to be unregulated, which is not acceptable. There is no proven option available to install voltage regulators at this station. Space to physically place them, available points in which to connect them in series, and electronic controllers that need to work in an

abnormal paralleled fashion are all issues that would have to be solved. There is no way to quickly repair or mitigate this given the current facility.

Without the availability of a spare unit, one must be ordered. Lead times for transformers have varied but are currently around 3 years. In the meantime, while the order was being manufactured, delivered and installed, the N-1 case (e.g., another transformer or LTC or tie line failure) would leave half of downtown without power and no way to mitigate.

- <u>Relaying Archaic: Last 115 kV Blocking Schemes on Avista's System</u>
  - Issue: Transmission line relaying at Metro is electromechanical-based (primarily KD relays). The fleet is on average over 40 years old, is past its usefulness as it is archaic equipment and provides no operational visibility or records for event analysis after a system disturbance. Additionally, the Metro-Sunset line is the last transmission line in Avista's system to use a carrier blocking scheme. Newer schemes communicate with the system as to faults or status of other equipment or faults on the system. While dependable, blocking schemes are less secure in nature.

  - Risk: Relay failures may not be able to be responded to in a timely manner. Spares are limited to those which have been retired from other stations. Expertise around setting KD relays has left the company. The last carrier blocking scheme is a threat to mis-operate, resulting in unnecessary transmission outages, decreased reliability, and FERC PRC-004 reporting.

1.2 Discuss the major drivers of the business case.

The Metro 115kV Station Rebuild project fits firmly within the **Asset Condition** and **Customer Service Quality and Reliability** drivers. Put simply, this project replaces old equipment with new equipment, which resets the curve with regard to asset life cycles, while also decreasing the likelihood of catastrophic equipment failures and resultant customer outages over the next 50 years.

However, elements of other investment drivers also apply. The end product of this project will allow construction and operations to occur without violating OSHA-driven circuit grounding requirements (one example of several **Compliance** drivers). It will also have upgraded feeder exits in the Metro East quadrant, which are presently at overload limits and need to be upgraded regardless. The transmission configuration allows more operational flexibility for 115 kV lines on both the South Hill and West Plains (**Performance & Capacity**). Finally, the completion of this project avoids a very costly and slow response to major equipment failures (any transformers, LTC's, switchgear, 115 kV breakers) which would likely end up translating into customer outages, unplanned **Failed Plant** expenses and a negative public image for Avista.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The risks associated with the existing Metro substation are significant and could include extended outages for half of the downtown area that is fed via Metro and Post St. The mobile substation is not an option at this location to stand up the site and keep the downtown area energized due to space constraints and technical incompatibilities. Beyond a temporary tie-line solution in the event of a transformer outage, there is no other option to maintain critical service to our downtown customers. Safety risks include significant fire risks to adjacent structures and occupants that are within 50 feet of the oil-filled equipment. Additionally, the switchgear which is not arc-flash rated puts personnel at risk as they must be inside the front of the cubicle to manually switch it. The risks of not moving forward with the new site and substation include the latter but also the negative public impact of not being able to provide power to the heart of the City for an undetermined amount of time. Due to the long lead times of major equipment (3 years for transformers) and the length of time to construct such a large and unique substation, the cost of the project is substantial. The longer the project takes to start and complete construction and energize, the higher the overall project cost, and there is an increase in the potential risk of older equipment failure.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

The Metro Substation project is the epitome of our Vision: "Better Energy for Life". We already serve the downtown core with the current Metro substation, but we want to do it better by supplying electricity more safely, more reliably, and more responsibly. We aim to accomplish this by addressing safety and reliability issues that the current Metro Substation has and do it in a responsible way by engaging stakeholders well.

The new Metro Substation will use some of the latest technology in substation construction. As such, it aligns with our mission. Metro is an innovative energy solution that will improve our customers' lives safely, responsibly and affordably. As stated before, the new Metro Substation will address a number of safety and reliability issues that the old Metro Substation has. We intend to do this responsibly and affordably. Nothing is planned for the project that isn't a request from a stakeholder (City of Spokane, for example) or isn't necessary from an operational or safety requirement.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Please refer to the Project Initiation Charter document that includes the following memos in addition to the sections above:

- Metro – Operational Risks & Challenges of Existing Configuration: Categorizes and summarizes the risks and challenges posed by the existing configuration of our electrical system in and around Metro Substation.
- Metro – Mitigation Options & Costs: Categorizes and summarizes mitigation options and their associated costs for operational issues identified at Metro Substation.
- 115kV Metro Substation – Rebuild Options: History of the Metro Substation and its relation to the Spokane Central Steam Heat Plant, summarizes issues with each Equipment Type in the Metro Substation (as of 2009).
- Metro Station System Impact Study by System Planning: Technical analysis of the Metro Substation rebuilds impact to the transmission system in the region.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

In the table below, the project options and mitigations were identified and evaluated for cost, feasibility, and risk early in the Initiation phase and documented in the Project Charter. These options were re-evaluated and updated in Fall 2022. As detailed in the table below, the Rebuild on New Site was selected as the best, most cost-effective and feasible option to proceed with. Further detailed documentation of the options are included in the Project Charter and supporting documents. Based on the Project Initiation Charter, it is recommended that the station be rebuilt on new property approximately two blocks to the south. The rebuilt station will utilize an open-air transmission bus design with metal-clad switchgear on the distribution side. Both transmission and distribution busses will be arranged in a ring configuration.

The rebuild of Metro on a new site mitigates nearly all concerns and risks associated with the existing installation. Reference the table below and in Section 2.5 for alternative costs, risks and risk reduction. It also provides a better operating configuration that will result in much lower impacts as failures are (inevitably) observed over the life of the installation. For example, a 115 kV breaker failure at the new Metro will not result in a full station outage. In fact, depending on the exact nature of the failure, it may not result in any outage at all. At the old station, half of Downtown could be out of power.

O&M costs associated with the new station would be the lowest observed relative to all options.

Options	Capital Cost	Estimate Class	Reduced Risk
SELECTED: Rebuild on New Site	**$73M**	Class 3	93%
1) Status Quo	$0	-	0%
2) Selective Mitigation at Existing Site	$12M (Years 1-6)	Class 4 High Risk	44%
3) Rebuild on New Site (GIS)	$97M	Class 5	93%
4) New Transmission Site, Rebuilt Distribution Site	$85M	Class 5 Not Feasible	91%
5) Downtown West & Downtown East	$103M	Class 5 Not Feasible	82%

Class 5: -20% to +100% Strategic Planning & Concept Level
Class 4: -15% to +50% Order-of-Magnitude, Feasibility Study
Class 3: -10% to +30% Budgetary, Semi-Detailed

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

In 2019 and 2020 multiple assessments and analysis were performed as part of the evaluation of the existing substation, scoping for the new substation and preparations for the new Metro Substation Project Charter that was approved in 2021. Refer to section 1.5 for a list of the reference documents. During these assessments, several options and alternate locations were evaluated for cost, risk and risk reduction, reliability, redundancy, capacity, and how they improve or mitigate current issues and risks for the Downtown core and our customers (Reference sections 2.1, 2.5, and 2.6). The summary of the information, assessments, analysis, and documentation provided in and referenced within this document were all considered when preparing this capital request.

	IRR	Annual Revenue Requirement
Base Case Rebuild on New Site	7.90%	$5,613,603
Alt 1 - Status Quo	6.38%	$5,894,718
Alt 2 - Selective Mitigation at Existing Site	4.82%	$7,251,968
Alt 3 - Rebuild on New Site (GIS)	4.03%	$8,132,620
Alt 4 - New Transmission Site, Rebuilt Distribution Site	4.96%	$7,118,115
Alt 5 - Downtown West and Downtown East	3.64%	$8,639,873

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

There are no direct O&M savings if the Metro Substation is rebuilt. Any savings are offset by increased costs to inspect, test, and maintain a much larger station.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M		$0	$0	$0	$0	$0

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

2.4 Summarize in the table and describe below the INDIRECT offsets (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Asset Condition based equipment changeouts	$10,000 (Average)	$10,000 (Average)	$10,000 (Average)	$10,000 (Average)	$10,000 (Average)
O&M	Loaded Cost of One Additional Serviceman to help cover higher call out rates.	$180,000	$180,000	$180,000	$180,000	$180,000

Asset condition issues are present in several types of equipment at the current Metro substation (see Section 1.1 Substation Related Issues for details). Reliability and safety concerns are also present. These three types of issues cause the greatest number of Servicemen callouts. If the substation rebuild is completed, Servicemen will spend less time maintaining and 'limping along' equipment. They will complete the work more efficiently since the safety issues (i.e., switchgear arch flash) are not present and do not have to planned for (i.e., Arc Flash suits are not required). The savings could be as much as $180,000 per year in additional Serviceman labor (salary plus overhead costs) system wide.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

Status Quo/no Change. Capital Costs No capital costs in years 1 to 9, complete rebuild starting in year 10.

Risk: Small site, feeders are beyond thermal capacity, significant fire risk to adjacent buildings, breakers are arc flash risk during racking, no spare transformer or mobile option. failures may result in outages for half of downtown for unknown duration. There is no reduction in risk.

Alternative 2:

Selective Mitigation at Existing Site – Upgrade overloaded feeder exits, install arc flash prevention relaying, install larger battery bank, install newer AFR relays, and purchase spare transformer. Capital Costs - $12M in years 1 and 6 with a complete rebuild assumed in year 10.

Risk: Small site, significant fire risk to adjacent buildings, failures may result in outages for half of downtown for unknown duration.

Alternative 3:

Rebuild on New Site (GIS) – Installing Gas Insulated Switchgear would mean the need for contract labor to install the equipment and this equipment requires a high cost to install. Capital Cost - $97M.

Risk: Mitigates almost all risks but comes with a higher cost for specialty equipment and installation.

Alternative 4:

New Transmission Site, Rebuilt Distribution Site – Brownfield rebuild of Distribution and a need for a link between the old and new site makes this option complicated and expensive. Capital Cost - $85M.

Risk: Mitigates some issues but is costly because the existing site would still have to be rebuilt and upgraded with newer distribution equipment and still is a fire hazard to the adjacent building.

Alternative 5:

Downtown West & Downtown East – (Additional options considered in Fall 2022): Downtown West is needed to off-load College and Walnut substation. Downtown East does not have property. Capital Cost - $103M.

Risk: Mitigates some risks but doesn't offload the existing Metro loads nor fully support downtown. Both sites would have to be developed in order to support the downtown area. These sites are identified as additional needs for other upcoming customer loads and future expansions. Both locations would require significant relocation of underground distribution and transmission lines throughout the downtown streets.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Over the life of this station, Spokane and the downtown loads have grown. OSHA-driven work practices for electrical workers have evolved, as have the IEEE standards for arc flash and distances between equipment and structures. Avista's tolerance for risk has changed. The existing station falls short of serving today's load in a safe and reliable manner and will only get worse over time. Reliability for our most critical downtown customers, including the hospitals, is essential. There are also unique possibilities for catastrophic failure at this site, with little or no good options for operational mitigations including the inability to use a mobile transformer. Potential equipment failures could result in outages to half of the downtown core for an undetermined amount of time, as well as fire risks to adjacent buildings and occupants. The rebuild of the Metro substation would provide the reliability and redundancy necessary to mitigate outage concerns. The new equipment would meet the IEEE standards for arc flash and the distances between structures and equipment would be resolved on this larger site. Monthly monitoring and controlling of the project budgets, schedules, and scope will be performed by the team with further discussions or analysis as needed throughout the project duration.

Transmission-Related Issues

- 2028-2033 No outages affecting both MTR-PST and 3HT-PST lines because of the shared duct bank
- 2028-2033 No outages on the 3HT-PST line from shared use of the Metro tunnel
- 2028-2033 No outages on the 3HT-PST line from non-utility workers having access in an area without NESC clearances
- 2028-2033 No outages on the MTR-SUN line's four original structures north of I-90
- 2028-2033 No outages on the PST-3HT line's three self-supporting steel and one wood structure north of I-90
- 2028-2033 No single transmission line trips cause a full Metro Substation outage

Distribution-Related Issues

- 2028-2033 No deaths from arc flash racking by cablemen
- 2028-2033 No failures of feeder exit cable due to it being run over capacity
- 2028-2033 No canceling of surgeries at Deaconess due to College & Walnut feeder outages

Substation-Related Issues

- 2028-2033 No non-momentary outages at the Metro Substation because the air switches did not operate properly
- 2028-2033 No fire started at adjacent buildings to Metro Substation
- 2028-2033 No battery voltage issues not reported through SCADA
- 2028-2033 No cascading cabling overload events during switching orders

2.7 Please provide the timeline of when this work is scheduled to commence and complete, if known.

This project is planned for construction over multiple years. The bulk of the project is planned to transfer to plant once construction of the substation is complete.

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2023	$16,200,000	$0
2024	$21,340,000	$6,000,000 (CIRCUIT BREAKERS/WALL CONSTRUCTION)
2025	$14,010,000	$3,200,000 (AUTO TRANSFORMERS RECEIVED)
2026	$9,790,000	$55,800,000 (SUBSTATION CONSTRUCTION COMPLEX)
2027	$5,160,000	$6,000,000 (COMMUNICATION/SECURITY COMPLETE)
2028	$2,000,000	$2,000,000 (FINAL CHARGES)

This project initiated in 2020 with the completion of studies and analysis and the signing of the Project Charter in early 2021. Design began and will continue through 2023. Construction of the enclosure wall, cable vault, control and battery enclosure, and duct banks is to occur in 2023 and 2024. Avista crews will perform build out of the substation into 2026 with anticipated completion in late 2026 and into 2027 for cutovers and final energizations.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Glenn Madden – Business Case Owner/Manager, Engineering Substations

Brian Vandenburg – Manager, Engineering Projects

Brian Chain – Sr. Engineer, Downtown Network

Aaron Henson – Principal Engineer – Substation - Civil

Brian Parsons – Sr. Engineer, Substation - Civil/Structural

Patrick Henderson – Sr. Engineer, Substation Engineering - Electrical

Bryan Hyde – Sr. Engineer, Transmission Engineering

Tim Figart – Principal Engineer - Electric Distribution Design

Crystal Holmes – Project Manager, Electrical Engineering Project Delivery

Mike Lang – Project Manager, ET/Comm/Network/Security Project Delivery

Power Engineers – Substation Design Consulting Engineers

The Substation project progress, schedules, and budget are tracked and communicated monthly with the Business Case owner and department Director. Any necessary quarterly updates for SOX are made, as well as yearly project budget requests are coordinated through the Business Case owner and the CPG as necessary. Larger project issues involving scope, schedule, and/or budget are brought forth to the project team noted above and any communications and/or recommendations including any change requests would be brought forth to the Sponsor/Director-level stakeholders, as applicable.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the ***Metro 115kV Substation*** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designate d representatives.

DocuSigned by:

Signature: Glenn J Madden Date: May-11-2023 | 11:32 AM PDT

Print Name: Glenn Madden

Title: Manager, Substation Engineering

Role: Business Case Owner

DocuSigned by:

Signature: Vern Malensky Date: May-09-2023 | 1:50 PM PDT

Print Name: Vern Malensky

Title: Director, Electrical Engineering

Role: Business Case Sponsor

DocuSigned by:

Signature: Brian Vandenburg Date: May-09-2023 | 1:51 PM PDT

Print Name: Brian Vandenburg

Title: Manager, Engineering Projects

Role: Steering/Advisory Committee Review

Metro 115kV Substation

1.0 CHANGE REQUEST #03 – 202312

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
12-2023	Revised Cost	03	$11,500,000	$4,700,000		
09-2023	Timing Change, Internally Driven	02	$13,100,000	-$1,600,000	-$1,600,000	$11,500,000
07-2023	Revised Cost	01	$0	$13,100,000	$13,100,000	$13,100,000

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
07-2023	Revised Cost	$190,000	$190,000	$0	$0
09-2023	Timing Change, Internally Driven				
12-2023	Revised Cost				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	$0	$19,500,000	$190,000	$190,000	$0	$0
2025	$0	$14,100,000	$190,000	$190,000	$0	~$5,000,000
2026	$0	$11,800,000	$190,000	$190,000	$0	~$5,000,000
2027	$0	$6,500,000	$190,000	$190,000	$0	~$55,000,000
2028	$0	$3,500,000	$190,000	$190,000	$0	~$3,800,000

*From New 5-year Business Case Request 2024-2028. This includes all business case changes not just this in-year request.

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Metro 115kV Substation

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

7/2023: The Metro 115kV Station Rebuild project was initially funded from the Substation – Station Rebuilds Program Business Case. Due to its large scope and cost, the Metro project has become its own Business Case as of March 2023. This fund change is now requested to move budgeted dollars from Substation – Station Rebuilds Program Business Case to the Metro 115kV Station Rebuild Business Case.

See the corresponding documentation for the Substation – Station Rebuild Program Business Case fund giveback.

09/2023: Based on adjustments to the scope of Transmission and Distribution Engineering portions of this project that can be completed this year with the construction sequence and available resources and the removal of contingency, the Metro project can reduce.

12/2023: The total Expected Spend for the Metro Substation Rebuild in 2023 is $16.25M. This includes the $3.7M of transactions from previous years that were transferred from the Substation – Asset Condition business case in September. Budget Item Breakdown:

BI	Expected Spend	Expected Spend with $3.7M Transfer
SC301	$4,000	$4,000
SC302	$50,000	$50,000
SD315	$2,500,000	$2,500,000
SS304	$9,600,000	$13,350,000
ST322	$350,000	$350,000
Total	**$12,504,000**	**$16,254,000**

There is an increase of about $800k under the SS304 BI (this is the Substation construction BI) due to cost increases related to the Wall construction and the early arrival of the Switchgear breakers (planned for 2024).

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Brian Chain	BC Owner	DocuSigned by: Brian Chain C4012FF13CFC491...	Dec-15-2023 | 6:33 AM PST
Vern Malensky	BC Sponsor	DocuSigned by: Vern Malensky 06C4FF5AB09E40B...	Dec-15-2023 | 7:10 AM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Monroe St. Abandoned Penstock Stabilization

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Project accounting determined that the investigation leading to the construction effort should be classified as operations & maintenance (O&M) rather than capital. Without knowing the results of the investigation, no asset from the retirement unit catalog could be identified as being affected by project work. For this reason, most charges for the project were classified as O&M. Only work related to the installation of piezometer monitoring wells could be capitalized, which explains the variance in expected vs. actual spend.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Two funds change requests (FCRs) were submitted for this project. The initial FCR was submitted upon receiving the determination that project would be classified as O&M. This resulted in a giveback of the majority of funds approved in 2022. The second FCR was submitted in 2023 to return capital dollars associated with the ongoing O&M investigation work.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no offsets associated with this project.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

Greg Wiggins

X Greg Wiggins (Feb 23, 2024 12:03 PST)

DIRECTOR SIGNATURE:

David Howell

X David Howell (Feb 23, 2024 07:42 PST)

Monroe St Abandoned Penstock Stabilization

1.0 CHANGE REQUEST #1 – [8.10.2022]

Previous Requests	Requested	Approved
5-Year Plan (2022)	$150,000	$150,000

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	YTD Spend	Current Approval	Requested Change	Proposed Annual Total
07-2022	$867.05	$150,000	-$140,000	$10,000

Type of Change	In-year Update
Primary Reason for Change	Scope Change
Response needed by	9/1/2022

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

Project accounting determined that the investigation leading to the construction effort should be classified as operations & maintenance. For this reason, we would like to return $140k in approved capital funding to the CPG this year, utilizing the remaining funds for the design and installation of monitoring wells for the project and for the construction effort in 2023. Our total approved project budget would become $10k in 2022 and remain $750k in 2023.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

If the funds are not returned, they will not be utilized by the project. The primary risk is underutilization of department funds.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Project accounting determined that the investigation work will be operations and maintenance because the work will not include equipment installations or removals with the exception of the installation of monitoring wells at several drill locations. The monitoring well design and install will be classified as capital. Project Accounting further advised that once the 'how' of penstock stabilization is determined, any equipment and labor associated could be considered for capital work. We plan to proceed with this guidance.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

There will be an additional $140k in O&M costs due to this shift.

Monroe St Abandoned Penstock Stabilization

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

The project team made the case to project accounting that the investigation served as field work in support of engineering due to the high likelihood of construction following the work. Project accounting disagreed, and we will follow their guidance in classifying the work as O&M with the exception of the design and installation of monitoring wells.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The project will still serve the needs stated in the original business case. The investigation work is needed for design, and the remediation work resulting will require capital dollars.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative remains valid.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
	BC Owner		
	BC Sponsor		
	FP&A		

1.0 CHANGE REQUEST #2

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
07/2022	*Revised Cost*	1	$150k	-$140k	-$140k	$10,000
10/2023	*Schedule Change*	2	$750k	-$720k		$30,000
	Choose an item.					

* See note in description for details on the revised budget amount

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
10/2023	Revised Cost	N/A	N/A	$750k	$30k

No O&M offsets are expected to be realized for this work.

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This should not be considered approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	$0k	$550k	N/A	N/A	$550k in 2023	$550k
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

In 2022 project accounting made the determination that the site analysis and investigatory drilling effort associated with the Monroe St. Penstocks project would come from the Operations & Maintenance budget. Following that determination, Budinger was engaged to perform the analysis as an O&M effort in 2023 as soon as their equipment was available to Avista. Through March of 2023, non-invasive analysis measures like the topographical survey and ground penetrating radar study were completed. The team then had to interpret this data to prepare a Drilling Program Plan for submission to the FERC, which was completed in May of 2023. FERC response was expected within sixty days of submission but was not received until August 16, 2023. FERC denied the Drill Plan, and the project team provided a revised Drill Plan on August 28, 2023. Budinger was unable to commit resources to the Monroe St. Project without assurance of our approval, and project work was pushed back in 2024. FERC approval of the revised drill plan was received September 7, 2023, and Budinger has been scheduled to complete the investigatory drilling beginning November 6, 2023. This was the earliest available time Budinger could complete the work following FERC approval, but it has shifted the project schedule such that only a portion of the capital work can be completed in 2023.

Referencing the project tasks, below, you will see the breakdown of project work by budget category. Budinger expects to complete the majority of O&M work this year, plus the installation of piezometer monitoring wells which is considered capital. The project is asking to retain the money allocated for the monitoring wells this year, which will result in about $30k in capital charges. O&M work will close-out in early 2024, and the project is requesting capital funding in 2024 to complete the remaining capital work. Total capital costs in 2024 are expected to be $550k. Note that because the remediation plan has not been fully scoped there is uncertainty around the $550k forecast.

In summary, the project will be giving back $730k in capital dollars in 2023 due to FERC-related project delays. The project will complete approximately $30k in capital work in 2023 and expects to spend $550k in capital work in 2024.

Task	Budget Category	% Complete in 2023	% Complete in 2024
Desk Study & Site Visit	O&M	100	0
Site topographical survey	O&M	100	0
Ground Penetrating Radar survey	O&M	100	0
Pre-exploration conference prep	O&M	100	0
Pre-exploration conference	O&M	100	0
Exploratory Drilling	O&M	100	0
Piezometer Standpipe Drilling & Closure	Capital	100	0
Drilling Coordination	O&M	100	0
On-Site Drilling Support	O&M	90	10
Geotechnical Design Report Preparation	O&M	75	25
Geotechnical Design Report Coordination	O&M	50	50
Penstock Remediation Design	Capital	0	100
Intake Remediation Design	Capital	0	100
Construction Drilling Program Plan Preparation	Capital	0	100
Mobilization and Demobilization for Remediation	Capital	0	100

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Site Cleanup for Remediation	Capital	0	100
As-built documentation for remediation	Capital	0	100
General conditions associated with remediation	Capital	50	50

The analysis work will be completed in 2023, as anticipated, for $150,000. Following non-invasive analysis measures like a topographical survey and ground penetrating radar, a Drilling Program Plan was prepared and submitted to the FERC.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature
Ryan Bean	BC Owner	
Alexis Alexander	BC Sponsor	
	Steering Committee (If applicable)	

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Network Backbone Infrastructure

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This business case includes investment in communication network infrastructure for expansion requirements and periodic refresh of our mixed service transport backhaul solutions. This work is comparable to a Transmission service but instead of electricity, we are transporting communication network data.

For the tracking year of 2023, the Network Backbone Infrastructure business case planned to transfer-to-plant approximately $3,879,878 in project work, while actually transferring approximately $1,450,064. This resulted in an under-transfer amount of approximately $2,429,814.

In 2023, adjustments were made to priority work such that anticipated projects were moved into future time periods and in some cases, a new business case called NexGen or to the existing Fiber Network Leased Services Replacement (FNLSR) business case. Resource and product availability also impacted the ability to deliver work. For example, these projects were key to the change in transfer to plant amounts in 2023:

- At least 4 microwave projects were moved to future years based on an adjustment to roadmap adjustments.
- The microwave project for Monumental Mountain to Mount Spokane was brought into 2023
- The Rathdrum to Newport OPGW project was brought into 2023 as an opportunity to partner with the Transmission and Distribution group.
- This table highlights the degree of change to the TTP plan

Project	Original Plan	Actual Result
MW Refresh Kettle Falls to Monumental Mt	$785,003	$0
MW Refresh Kettle Falls to Monumental Mt	$779,139	$0
MW Refresh Kettle Falls to Monumental Mt	$823,250	$0
Fiber approach for new path going north	$113,444	$0
Hatwaii (HAT) to Moscow M23 Fiber Expansion	$820,025	$711,049
MW Expansion Colville Mtn to Colville Office	$540,120	$0
MW Monumental Mountain to Mt. Spokane	$0	$295,667
Rathdrum to Newport OPGW - Ph 1	$0	$443,348
Other Work	$18,897	$0
Totals	**$3,879,878**	**$1,450,064**

PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. The following business case change requests and governance documents are attached with further details surrounding the above explanations.

- Change requests dated May/June 2023 – Reduced the business case as projects were moved out and helped fund the new NexGen business case - $2M Total for May and June.
- Change request dated September 2023 – Reduced the business case by $400k due to delays in construction on microwave projects.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are not any changes to the indirect offsets that would be calculated for this business case based on the under transfer amount listed above.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Shawna Kiesbuy
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DIRECTOR SIGNATURE:

X DocuSigned by: Alexis Alexander
EA27BABA767F467...

1.0 CHANGE REQUEST #01 – 2023.05.17

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
5/17/2023	*Scope Change*	01	$5,357,790	($1,000,000)		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
5/17/2023	Scope Change	$0	$0	$2,226,739	$2,226,739
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Network Backbone Infrastructure Program Business Case includes investment in communication network infrastructure for expansion requirements and periodic refresh of our mixed service transport backhaul solutions. Since five-year planning was completed last year, eight Microwave Refresh, SONET, and fiber expansion projects have been moved to future years and into the new business case, NexGen Control Systems Networks, resulting with excess approved funding. The project moves are based on risk assessments and alignment of products to specific use cases. Since this is a release of funds, no alternatives were reviewed.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: 3CD905A81B984C3...	May-15-2023 | 7:50 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	May-15-2023 | 12:06 PM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

1.0 CHANGE REQUEST #01 – 2023.06.21

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
5/17/2023	*Scope Change*	01	$5,357,790	($1,000,000)	($1,000,000)	$4,357,790
6/21/2023	*Scope Change*	02	$4,357,790	($1,000,000)		
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
6/21/2023	Scope Change	$0	$0	$2,527,307	$2,527,307
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Network Backbone Infrastructure Program Business Case includes investment in communication network infrastructure for expansion requirements and periodic refresh of our mixed service transport backhaul solutions. Since five-year planning was completed last year, eight Microwave Refresh, SONET, and fiber expansion projects have been moved to future years and into the new business case, NexGen Control System Networks, resulting with excess approved funding. The project moves are based on risk assessments and alignment of products to specific use cases. Since this is a release of funds, no alternatives were reviewed.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: 3CD905A81B984C3...	Jun-18-2023 | 7:06 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Jun-20-2023 | 10:09 AM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Network Backbone Infrastructure

1.0 CHANGE REQUEST #03 – 2023.09.20

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
9/20/2023	*Scope Change*	03	$3,357,790	($400,000)		
6/21/2023	*Scope Change*	02	$4,357,790	($1,000,000)	($1,000,000)	$3,357,790
5/17/2023	*Scope Change*	01	$5,357,790	($1,000,000)	($1,000,000)	$4,357,790

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
9/20/2023	Scope Change	$0	$0	$2,527,307	$2,611,669
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	$2,500,000	$3,500,000			$6,000,000	$4,528,289
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Network Backbone Infrastructure

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Network Backbone Infrastructure Program Business Case includes investment in communication network infrastructure for expansion requirements and periodic refresh of our mixed service transport backhaul solutions. Many of the projects are construction based and subject to outside environmental and external risks. For example, the Sandpoint Baldy to Sandpoint Office Microwave Refresh project experienced many schedule delays this year due to contracting discussions between the city of Sandpoint and Bonner County, along with the work to make the road to the mountain top site safe for travel for our crews and their equipment, which was new scope for the project. A related project, Sandpoint Baldy to Mt. Spokane Microwave Refresh has also been delayed since its schedule will align with the project listed above resulting in forecast being moved into 2024. As a result, this change request is releasing $400,000 in approved funding.

Since this change request is a release of funds, no alternatives were reviewed at this time.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Sep-18-2023 | 2:09 PM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Sep-18-2023 | 2:51 PM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

New Revenue - Growth

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE

Avista defines these investments as "customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a single large customer." Electric and Gas devices are also included in this business case -Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter) to be used for a range of purposes such as replacing failed plant, connecting new customers, and replacing equipment that no longer meets standards. Supply chain challenges caused most of the transfer to plant variance. The Company has seen notably higher unit prices. Transformer and gas meter purchases led to nearly $30M of the variance.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

It is required to connect new customers when feasible, and prudent to source a stock of critical equipment.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no direct O&M offsets associated with the New Revenue - Growth business case. The New Revenue - Growth Business Case is driven by tariff requirement that mandates obligation to serve new customer load when requested within our franchised areas. Expected revenue associated with growth plant are included as "other revenue" in the Company's Offset Adjustment (4.03 and 5.09). Any change in billed revenue would flow through the decoupling mechanism.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: Paul D Good

DIRECTOR SIGNATURE: Paul D Good

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

NexGen Control System Networks

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

This business case will administer projects specifically scoped to replace products and services on our control system communication networks that have been designed and provisioned over time division multiplexing (TDM) methodologies. TDM based products and services are end-of-life, end-of-support and are at the end-of-manufacturing. As vendors are ramping down on the manufacturing and support of TDM based products and services, local exchange carriers and other telecommunication service providers are also removing these services from their own product portfolios, recognizing that these services are no longer viable products to maintain. Local exchange carriers and vendors alike have both issued notices to Avista to sunset these products and services. If we do not address the existing services before they are disconnected or out of support, we risk losing communication network services that carry control and telemetry traffic, critical to our ability to operate our gas and electric systems.

Notice of the changes were provided in early 2023 and some services were said to be ending as soon as 2024. Thus, creating this business case to manage this work became urgent along with aggressively starting to plan and execute on the work

For the tracking year of 2023, this business case planned to transfer-to-plant was $0 since this business case did not existing for the reporting period where initial transfer to plant numbers were pulled. In 2023 $694,741 was transferred to plant by way of the SCADA comms phase 1 project.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. The following business case change requests and governance documents are attached with further details surrounding the above explanations.

- A change request was approved in June 2023 for the initial funding of this business case as it come into being. No other change requests were processed.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are not any changes to the indirect offsets that would be calculated for this business case based on the over transfer amount listed above.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Shawna Kiesbuy
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DIRECTOR SIGNATURE:

X DocuSigned by: Alexis Alexander
EA27BABA767F467...

EXECUTIVE SUMMARY

This NexGen Control System Networks (NCSN) Program[1] Business Case will administer projects specifically scoped to replace products and services on our control system communication networks that have been designed and provisioned over time division multiplexing (TDM) methodologies. TDM based products and services are end-of-life, end-of-support and are at the end-of-manufacturing. Through a series of Declaratory Rulings and Orders from 2014 thru 2018, the FCC allowed for a local exchange carrier (LEC) to discontinue TDM services and permitted LECs to leverage universal service funding support for investment in more modern and efficient software defined IP based networks. As vendors continue ramping down on the manufacturing and support of TDM based products and services, local exchange carriers (LECs) and other telecommunication service providers continue removing these services from their own product portfolios, recognizing that these services are no longer viable products to maintain. Local exchange carriers and vendors alike have both issued notices to Avista to sunset these products and services. If we do not address the existing services before they are disconnected or out of support, we risk losing communication network services that carry control and telemetry traffic; data that is critical to our ability to operate our gas and electric systems. The services to be scoped for removal as part of this business case are:

- Leased public interconnections with local exchange carriers via TDM services, i.e., DS0 and DS1 circuits Avista is leasing.
- Private TDM services for public interconnections, i.e., our SONET network and circuits provisioned specifically for SCADA communications via interconnection agreements with Bonneville Power Authority (BPA) and others across the bulk electric system.
- Private TDM services for private communication services, i.e., our SONET network and circuits provisioned specifically to transport Avista control and telemetry traffic for our own purposes.

Use Cases currently being served by TDM network services Include:

- Teleprotection communications, including RAS
- Intercompany telemetry with BPA, Grant County PUD, PacifiCorp, etc.
- SCADA Telemetry
- Analog voice traffic at some substations and communications sites
- Point-to-point enterprise backhaul at some remote offices

For this business case, funding is being requested for $22,728,000 over 6 years to upgrade or replace 124 communication network circuits and node sites that carry traffic for the above listed use cases. This business case is collecting and documenting all existing replacement projects that have been forecasted under separate business cases, plus unforecasted replacement projects that are driven by vendor disconnect and end-of-life notifications and sequencing the work under a

single business case for visibility, facilitation and heightened awareness. As an offset, some of the refresh and/or replacement activities are already planned or in progress in the 5-year capital forecast under separate cover of projects in other capital business cases. Examples are:

- Digital Grid Network – The project titled “NCSN SCADA Comms Refresh_01” has started accumulating actuals as of February 2023. This project is currently forecasted to spend $582,612 in 2023 and $17,388 in 2024 and will deliver design standards and implement updated communications network capabilities at two locations that are TBD and based on risk and impact.
- Control and Safety Network Infrastructure – DNX infrastructure hardware components have been discontinued by the vendor and will be refreshed as part of the SONET work now taking place in this new business case. These four projects equate to $850,893 of forecasted project work in the current approved five-year plan.
- High Voltage Protection – That business case will be shut down after 2024 investments, recovering $1,000,000 in approved spend across 2023 thru 2027. The leased network services and associated safety risks at substation sites requiring high voltage protection packages will be disconnected by the local exchange carrier as part of this move away from TDM based circuits.
- Network Backbone Infrastructure – SONET replacement work is currently forecasted to invest $6,256,472 in capital network infrastructure from 2023 thru 2027 within the current approved five-year plan, with another $3,157,035 forecasted in 2028. This would replace 72 SONET nodes across the network that currently leverage TDM methodologies, hardware and equipment.
- $8,107,365 (harvested forecast dollars from CSNI, HVP & NBI)

VERSION HISTORY

Version	Author	Description	Date
1.0	*Shawna Kiesbuy*	*Initial draft of original business case*	*3.9.2023*

BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements with suggested changes*	*4/20/2023*

[1] "A Program is defined as related projects, subsidiary programs, and program activities managed in a coordinated manner to obtain benefits not available from managing them individually. Managing projects, subsidiary programs, and program activities as a program enhances the delivery of benefits by ensuring that the strategies and work plans of program components are responsively adapted to component outcomes, or to changes in the direction or strategies of the sponsoring organization.", Project Management Institute Global Standard, *The Standard for Program Management, Fourth Edition. Page 3* (Copyright 2017).

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2023	**$2,976,000**	**$600,000**
2024	**$7,752,000**	**$6,376,000**
2025	**$3,000,000**	**$4,500,000**
2026	**$3,000,000**	**$3,000,000**
2027	**$3,000,000**	**$3,000,000**
2028	**$3,000,000**	**$4,800,000**

Project Life Span	*6 years*
Requesting Organization/Department	Enterprise Technology
Business Case Owner | Sponsor	Shawna Kiesbuy | Jim Corder
Sponsor Organization/Department	Enterprise Technology
Phase	Initiation
Category	Program
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

NexGen Control System Networks

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

TDM based products and services are end-of-life, end-of-support and are at the end-of-manufacturing. As vendors are ramping down on the manufacturing and support of TDM based products and services, local exchange carriers and other telecommunication service providers are also removing these services from their own product portfolios, recognizing that these services are no longer viable products to maintain. Local exchange carriers and vendors alike have both issued notices to Avista to sunset these products and services. If we do not address the existing services before they are disconnected or out of support, we risk losing communication network services that carry control and telemetry traffic, critical to our ability to operate our gas and electric systems.

1.2 Discuss the major drivers of the business case.

The telecommunications industry continues to move through its own series of disruptive transformations, much of which is centered around the move from circuit-based networks and TDM technologies to IP, or packet-based networks. As a significant portion of our communication network also leverage TDM technologies, if we do not act faster to implement this new architecture and the move to IP based networks for our control communications, we run a very real risk of not being able to view, manage or control our systems, which could negatively impact real time decisions needed to deliver safe and reliable services to our customers.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This work is needed to ensure that our workers have reliable data to control our systems. SCADA telemetry data, generation control data, protection circuit communications and capabilities are at risk If this work is not approved/deferred. The loss of remote control and data acquisition also means that personnel could be required to drive out to specific sites to manage, operate and support controls, which removes the efficiencies and real time decisions the company has been used to operating with. By having these communication systems updated through this program, we can increase our productivity by receiving real time data that will allow us to control our systems in real time and increase the safety of our employees.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

If we do nothing and decide to either de-prioritize and/or not fund this work, all four of the Focus Areas will be impacted, which would directly and indirectly impact the alignment to our values, mission & vision statements:

Our Customers – Our customers could see a negative impact to the reliable delivery of energy when the delivery of telemetry data which gives us situational awareness and control of the systems and devices that serves their energy is not delivered in real time.

Our People – Our employees could see a negative impact in their ability to operate and control the system on a real-time basis, adding safety risks and in-efficiencies to normal operating procedures.

Perform - We have built these real time data efficiencies into our daily operations and budgets. Sending crews to man locations without telemetry or control circuits would be cost prohibitive, inefficient and extremely disruptive to existing operations. We would be moving in the wrong direction of progress.

Invent – We are on the back end of the product lifecycle curve with TDM technologies. We must increase our cadence of deployments with current/newer network technologies to keep pace with markets, carriers, suppliers, vendors and other energy companies with whom we have interconnections and service relationships. Otherwise, we risk misalignments, obsolescence and an inability to move data, communicate and control.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The carriers we interconnect with to move control and telemetry data across our geographic region have recently issued written statements that they will begin disconnecting services in Q3 2024 and that they have already received regulatory approval to do so. Lumen is the first carrier in this region (and the last across the country) to issue a written disconnect statement and serves the largest number of circuits to be redesigned at 51 Avista circuits.

Additionally, GE has served us with a written email that also provides an end of service, end of manufacturing and end of support date for TDM based equipment that we use on network designs that carry traffic to and from interconnected entities, as well as our own control and telemetry traffic.

For the reasons above, and the risks to business operations, an exceptionally large portion of this programmatic business case is schedule driven.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

We will a) disconnect leased carrier services provisioned over TDM technologies and design solutions that integrate into our existing private utility MPLS network that is served via current and standard internet protocol solutions.

We will also disconnect our own SONET networks provisioned over TDM technologies and design solutions that integrate into our existing private utility MPLS network that is served via current and standard internet protocol solutions.

These two simple statements capture the large body of work to remove TDM technologies from our portfolio, thus removing the risk of misalignments, obsolescence and an inability to move data, communicate and control.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

The work in this business case supports and enables our ability to reliably operate our systems, providing remote visibility and telemetry data, as well as remote control capabilities.

According to Avista's form 10-K filed for the fiscal year ending December 31, 2022, the company's top Operational Risks highlight operational impacts related to wildfires, severe weather or natural disasters, incidents related to mechanical breakdowns, blackouts or disruptions of interconnected transmission systems, and even cyber-attacks which disrupt our technology systems. All these risks are monitored, and in some cases, even mitigated via the network communications technologies found in substations, on the distribution lines coming into and out of the substations and the transmission lines related to those same systems. This technology provides the remote visibility to realize a risk and take action when needed.

See the tables below in section 2.3 for MRC savings that will be realized once these leased services are disconnected.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2023	2024	2025	2026	2027
Capital	LightRiver Envision Plus Licensing	($54,081)	($54,081)	($54,081)	($54,081)	($54,081)
O&M	Carrier MRCs	($10,000)	($20,000)	($20,000)	($20,000)	($20,000)

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Offsets	Offset Description	2023	2024	2025	2026	2027
Capital		$0	$0	$0	$0	$0
O&M		$0	$0	$0	$0	$0

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

Do nothing and allow the circuits to be disconnected without capital investment to replace the network capabilities. The risks of not being able to see or control our electric system are too great to consider this alternative.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success will be measured by the continued, uninterrupted ability to transmit and receive data that allows for remote supervisory control and data acquisition, so that we can make expeditious and real time system operations decisions.

No loss of communications because of carrier disconnects or lack of vendor support is the success metric to be met. Throughout this multi-year initiative, we will continue to work with the carriers and vendors to stay/delay the disconnect of circuits and maintain hardware support in order to deliver uninterrupted communications that enable the operation of our system and the delivery of safe and reliable energy to our customers.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The NCSN SCADA Comms Refresh_01 project has started charging actuals in February of 2023 and is scheduled to complete in January of 2024. That is the first design iteration project, intended to deliver design standards and implement those designs at two locations. Future projects will be forecasted to replace the TDM leased circuits at the remaining 51 sites, sequenced based on the risk of losing communications and the impact to the business if communications are lost. A timeline and/or burndown chart will be created and maintained to show progress towards the goal of removing all leased carrier TDM circuits. Similar metrics will be created in future projects as we begin to remove TDM based SONET services from our private network and replace with current MPLS based networks.

No loss of communications because of carrier disconnects or lack of vendor support is the success metric to be met. Throughout this initiative, we will continue to work with the carriers and vendors to delay the disconnect of circuits and maintain hardware support in order to deliver uninterrupted communications that enable the operations of our system and the delivery of safe and reliable energy to our customers.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee members are invaluable to the business case and individual projects, and will provide approval on scope, schedule, and budget related changes. Additionally, they will provide approval on issues and risks pertaining to outlined project deliverables, which also typically have an impact on the scope, schedule, or budget of a project. Steering Committee members will also provide approval on Change Requests, Go-Live, and the Approval to Close documents. For this NexGen Control Systems Network business case, the Steering Committee will consist of the Directors and Managers within ET, Energy Delivery, GPSS and the Business Case Owner.

The NexGen Control Systems business case has two levels of governance: the Program Steering Committee and the Project Steering Committee.

Program Steering Committee
This business case is a program of related projects. The Program Steering Committee consists of members in management positions that are identified and responsible for prioritizing the projects within this program. The Steering Committee is also held accountable for the financial performance of this

program. The Program Steering Committee will have regular meetings to review the progress of the program and to make decisions on the following topics:

- Project prioritization and risk
- Approving business case funding requests
- New project initiation and sequencing

The Program will be facilitated and administrated by an assigned Program Manager within the ET PMO. The project queue will be reviewed periodically to plan and sequence work to the levels of funding allocation received against the risks being mitigated.

Project Steering Committee
Project Steering Committees function as the governing body over each individual project within the program and will consist of key members in management positions that are identified as responsible for the successful completion of the scope of work identified in the Charter document for the Project. The Project Steering Committee is responsible for providing guidance and making decisions on key issues that affect the following topics:

- Scope
- Schedule
- Budget
- Project Issues
- Project Risks

The Project Steering Committee will meet at the defined intervals documented in the Charter of the project and will be facilitated by an assigned Project Manager from within the PMO.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the NexGen Control System Networks and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Date:	May-15-2023 | 1:45 PM PDT
Print Name:	Shawna Kiesbuy		
Title:	Sr. Manager, Network Engineering		
Role:	Business Case Owner		

NexGen Control System Networks

Signature:	DocuSigned by: Jim Corder 7002E4872104449...	Date:	May-16-2023	10:07 AM PDT
Print Name:	Jim Corder		
Title:	Director, Infrastructure Technology		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

NexGen Control System Networks

1.0 CHANGE REQUEST #01 – 2023.06.14

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
6/21/2023	*Revised Cost*	01	$0	$1,766,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
6/21/2023	Revised Cost	$0	$0	$0	$600,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The NexGen Control System Networks (NCSN) Program Business Case will administer projects specifically scoped to replace products and services on our control system communication networks that have been designed and provisioned over time division multiplexing (TDM) methodologies. TDM based products and services are end-of-life, end-of-support and are at the end-of-manufacturing. Through a series of Declaratory Rulings and Orders from 2014 thru 2018, the FCC allowed for a local exchange carrier (LEC) to discontinue TDM services and permitted LECs to leverage universal service funding support for investment in more modern and efficient software defined IP based networks. As vendors continue ramping down on the manufacturing and support of TDM based products and services, local exchange carriers (LECs) and other telecommunication service providers continue removing these services from their own product portfolios, recognizing that these services are no longer viable products to maintain. Local exchange carriers and vendors alike have both issued notices to Avista to sunset these products and services. If we do not address the existing services before they are disconnected or out of support, we risk losing communication network services that carry control and telemetry traffic; data that is critical to our ability to operate our gas and electric systems. The only alternative discussed is to do nothing and allow the circuits to be disconnected without capital investment to replace the network capabilities. The risks of not being able to see or control our electric system are too great to consider this alternative.

This change request is to request the initial funding of the new business case for 2023. Funding requests for years 2024-2028 have been submitted as part of the 5-year planning process.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: 3CD905A81B984C3...	Jun-18-2023 7:07 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Jun-20-2023 10:10 AM PDT
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

1.0 CHANGE REQUEST #02 – 2023.11.15

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
11/15/2023	*Revised Cost*	02	$1,800,000	($625,000)		
6/21/2023	*Revised Cost*	01	$0	$1,800,000	$1,800,000	
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	**Request Type**	**Budgeted Savings /Offsets**[1]	**Revised Savings /Offsets**	**Currently Planned TTP**[2]	**Revised TTP**
11/15/2023	Revised Cost	($64,081)	*Still validating	$600,000	$633,646
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	**Budgeted Approved Amount**[3]	**Updated Funding Anticipated as a result of request**	**Budgeted Benefits /Offsets**[4]	**Revised Benefits /Offsets**	**Budgeted TTP**[5]	**Revised TTP**
2024	$5,752,000	$8,900,000	($74,081)	($74,081)	$6,376,000	$7,300,000
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The NexGen Control System Networks (NCSN) Program Business Case will administer projects specifically scoped to replace products and services on our control system communication networks that have been designed and provisioned over time division multiplexing (TDM) methodologies. TDM based products and services are end-of-life, end-of-support and are at the end-of-manufacturing.

This change request is to release funds from the business case in 2023 but will be needed in the business case in 2024. The current project schedules in 2023 have been delayed due to a protection engineering constraint on the SCADA Comms Refresh Phase 2, NCSN Circuit Refresh Fiber Approaches, and the NCSN Circuit Refresh Columbia Basin Hydro projects, along with a delay in contracting for the NCSN Circuit Refresh Columbia Basin Hydro project. These schedule delays are pushing project work from 2023 into 2024. Alternatives for this release of funds has been discussed with leadership, but at this time, professional services or additional staffing is not a viable option.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Shawna Kiesbuy	BC Owner	DocuSigned by: Shawna Kiesbuy 3CD905A81B984C3...	Nov-10-2023 | 9:40 AM PST
Alexis Alexander	BC Sponsor	DocuSigned by: Alexis Alexander EA27BABA767F467...	Nov-10-2023 | 3:38 PM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Nine Mile HED Battery Building

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Funding for 2023 was not previously identified as it was believed this project would wrap up in 2022. The Steering Committee approved increased scope (July 2022) to add an emergency generator to the plant as part of the emergency back-up system. An emergency generator previously purchased for use at Cabinet Gorge was deemed appropriate for Nine Mile though it was not outdoor rated. In order to prepare the generator for outdoor use, it was necessary to add an external enclosure. Installation of the enclosure took longer than expected and, wiring also presented some challenges not dealt with on previous emergency generator installations. These challenges also extended the project.

Long story short – the variance was due to two factors: addition of the emergency generator and labor costs for installation.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This business case is monitored by a steering committee made up of a cross-department group who meet each month throughout the project's execution phase. The decision to add the emergency generator to the scope of this project was agreed to on July 26, 2022.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets reported for this work. Maintenance costs will not be reduced; however, decreased impact from extended outages is expected.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Greg Wiggins
Greg Wiggins (Feb 23, 2024 11:59 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 23, 2024 07:40 PST)

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Nine Mile Powerhouse Roof Replacement

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

During scoping, it was determined that this work is really comprised of two separate elements: structural integrity and rooftop work. With this in mind, the project has been broken out into two (2) phases.
Phase I sought to remediate the internal truss supports for the powerhouse roof. This work was accomplished by strengthening the truss members with the addition of steel support. This work was completed and transferred to plant in June of 2023 at a cost of $841,634.
Phase II of this project will address the external powerhouse roof and associated components: membrane, parapet walls, safety railing, cameras, fan building, skylight penetrations, etc. A Request for Proposal (RFP) will be issued in Q2 for procurement of a General Contractor who will oversee all the work. Estimated project cost is $1.3mm. Work will be performed in summer of 2024 transferring to plant by October 31, 2024.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

An advisory committee was formed to support this project. This group met on February 17, 2023 and recommended a phased approach. The steering committee then met to review the recommendation and approved this approach on February 24, 2023.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

No offsets have been identified.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Gregory Wiggins
Gregory Wiggins (Feb 29, 2024 08:34 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 29, 2024 08:58 PST)

Follow-up: NM Roof Advisory Committee...

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Follow-up: NM Roof Advisory Committee Team Meeting 2/17/2023

Echegoyen, Terri
To Wiley, Rene; Bean, Ryan; Truex, Michael; Henscheid, PJ; Oestreich, Cynthia 2/17/2023
Cc Del Papa, Giovanni

Team,
Ryan, PJ, Gio, Cynthia and I met today to discuss plans to go forward with a two phased approach to the roof rehabilitation project at Nine Mile.

- Phase I: Truss Remediation - 2023
- Phase II: Rooftop Work - 2024

The advisory members agreed with this approach and advise proceeding with the truss remediation work this year to be completed by June 30th.

I will schedule a steering committee meeting to present this plan for their approval at their earliest convenience.

If you have any questions or concerns, please reach out.
Thank you,

Terri Echegoyen, She/Her
1411 E Mission Ave MSC-051, Spokane, WA, 99202
P 509.495.2199 | **C** 509.869.9236
www.myavista.com

Typical Work Location schedule:
Monday: Remote
Tuesday: Avista Corp Mission
Wednesday: Avista Corp Mission
Thursday: Avista Corp Mission
Friday: Remote

Date: February 24, 2023
Project: Nine Mile Roof Rehabilitation
Organizer: Terri Echegoyen
Participants: Jeff Vogel, Greg Wiggins, Jacob Reidt
Objective: Decision Point Phase I – Truss Remediation
Project/Task: 20505090/300100

Agenda

1. Project Status
    a. Advisory Committee met on 2/17 (PJ, Ryan, Cynthia, Terri, Gio); determined the best path forward would be to conduct the roof rehab in a phased approach:
        - Phase I – Truss Remediation - 2023
        - Phase II – Rooftop work - 2024
    b. Cynthia obtained approval from Alexis via email to sole source the truss remediation work with Knight (2/8/2023)
    c. Alternative scaffolding option presented by Knight
    d. Issues
        - Ryan suggested using Knight as GC for the truss work due to the variety of support work needed in this job (scaffolding, abatement, welding, inspection, etc). Cynthia does not feel this is necessary
        - Truss work must be completed before exterior rooftop work is started for safety reasons
        - If truss work takes place this year, it must be completed and demobbed by June 30th to make way for the Annual Maintenance crews to begin work after July 4th.
        - FERC: FERC's interest in the project falls under 18CFR12.11. We are required under our license to report modifications of the Project Works. I was asked to reach out to our FERC project engineer to see if this work fell under the reporting requirements, or whether this could be deemed as maintenance. Given that we are coining the project powerhouse "roof replacement" and it is in the capital space, calling this maintenance work may not be fitting. Right now, considering the truss work, the FERC is interested in learning more before commenting on what they may require. I suspect they will require a 60-day construction submittal with stamped plans and specification, and possibly a QCIP...maybe more. May ask for accelerator review.
2. Accounting
    a. Request separate Budget Items associated with single ER - 4236
    b. Five-year planning (2024-2028) for rooftop work

3. Approvals requested:
    - Proceed with phased approach? **YES**
    - Approval to proceed with Knight in Sole Source Capacity - **YES**
    - Approval to proceed with Safway for scaffolding, etc. - **YES**
    - Approval to proceed with AAI for both plans/spec and onsite consultation. **YES**
    - Approval to proceed with IRS for lead abatement **YES**

Nine Mile Powerhouse Roof Replacement

EXECUTIVE SUMMARY

The Nine Mile Falls generation plant is over 100 years old. The roof trusses and concrete slab is original construction, and the roofing membrane was possibly updated in 1984 - 38 years ago or more with temporary patches and repairs since. Many inspections conducted over the years have determined that the roof is leaking and deteriorating, and the most recent June 2021 inspection by Garland Roofing stated that "overall the roof system has come to the end of its serviceable life" and is badly in need of complete replacement. As the engineering team has investigated the roof's condition, more information has come to light revealing that the roof's steel truss members in their current state are overstressed supporting the roof system weight (concrete roof slab and roofing membrane material) alone with no extra capacity for live loads, such as snow. Additional concerns include the condition of the 100-year-old steel trusses, which have experienced some damage and corrosion over the years and still has the same 100-year-old coating system.

The recommended solution is to address the overstressed condition of the steel trusses and to replace the failed roof membrane system. The supporting steel truss members will either be upgraded to increase their structural capacity or the concrete roof slab panels be replaced with lighter weight roofing material to reduce load on the steel trusses.

The estimated cost for the roof is $1,000,000 to address both the structural and roofing needs. The service code for this program is Electric Direct and the jurisdiction for the project is Allocated North serving our electric customers in Washington and Idaho. Operating Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ryan Bean	Initial draft of original business case	8/18/2022	

GENERAL INFORMATION

Nine Mile Powerhouse Roof Replacement

Requested Spend Amount	$ 1,000,000
Requested Spend Time Period	1 Year
Requesting Organization/Department	C07/GPSS
Business Case Owner | Sponsor	Ryan Bean | Alexis Alexander
Sponsor Organization/Department	C07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The powerhouse roof at Nine Mile needs replacement due to age and deterioration. The current membrane leaks and the existing roof trusses are in an overstressed condition that requires remediation.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The driver for this business case is Asset Condition. The powerhouse roof is needed in good condition to protect the inner workings of the generating plant. Nine Mile supplies year-round base load hydroelectric power to Avista's portfolio. Continuing to operate Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The roof has reached the end of its serviceable life and is structurally deficient. If not addressed in the near future, the condition of the roof will continue to degrade, exposing the plant to water infiltration and potential failure due to its overstressed condition.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The measure would include restoring the structural integrity and watertight seal of the roof to provide years of service to come. By restoring the roof, we protect our ability to generate low-cost power for our customers.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

- NM Roof Structure Analysis Memo
- Roof Truss Steel Coupon Test Results

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Per roofing condition inspection, the roof has reached the end of its useful life.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
1. Address overstress and membrane condition	$1,000,000	01 2023	12 2023

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The failure of the existing roofing membrane is the primary metric for justification of the project. Investigative measures have been taken to determine the exact quality of the roof and its components. These measures include steel and concrete assessments and analysis. By addressing the problem, we mitigate the risk of water damaging critical generating equipment and/or roof failure.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e., what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M because of this investment.

The capital costs will be spread over 1 year. Current investigative efforts will inform selection of an appropriate structural remedy and those costs will be transferred to this project. Truss remediation will precede the roof membrane replacement in the fall. This will not offset significant O&M charges because roofing and roof trusses are low maintenance items.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

The execution of this project will enable the continued operation of Nine Mile Units HED. Plant production and reliability will be impacted without a sound roof.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

OPTION 1: Upgrade the 8 steel trusses by reinforcing the overstressed members to provide greater capacity.

Pro's:

- Regardless of what option is chosen, the roof trusses need to be maintained by sand blasting and painting
- Reinforcing truss members improves strength/capacity of truss for dead load and live load

Con's:

- Unloading the truss is tricky and could put a member designed for tension into compression; applied forces/stresses need monitored
- Lead abatement required (steel truss clean up and painting)

OPTION 2: Reduce the dead load weight on steel trusses by cutting out concrete sections of the roof and replacing with metal lightweight deck material.

Pro's:

- Regardless of what option is chosen, the roof trusses need to be maintained by sand blasting and painting
- Cutting out concrete sections reduces dead weight on truss members

Con's:

- Uneven areas where cutouts made?? Or can these areas be built up and then a new membrane applied and not have compromising uneven roof areas that create issues in the future?
- Dusty & concrete fines need contained (in powerhouse) during concrete cutting
- Lead abatement required (steel truss clean up and painting)

OPTION 3: Perform complete tear off the concrete roof and concrete beams over the trusses (unless it makes more sense to keep the concrete beams and just remove the slab) and replace with a new roof (metal deck & membrane roofing).

Pro's:

- Regardless of what option is chosen, the roof trusses need to be maintained by sand blasting and painting

- Reduces dead weight on truss members; new roof material would be much lighter than existing concrete roof

Con's:

- Extensive work and could be disruptive to plant operations
- Lead abatement required (steel truss clean up and painting)

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

Costs will be transferred to plant as the stages of work are completed. First will be the truss remediation followed by the new roofing membrane.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Operating Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES). By taking care of this plant, we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Nine Mile will continue to provide reliable service and mitigate risk to future projects and fielding unplanned failures.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Nine Mile HED is Avista's fifth largest hydroelectric plant. Roof projects of his size and complexity fall into this range of costs.

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. This includes the creation of a Steering Committee and a formal Project Team. Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance. The Project Manager will manage the project through its conclusion.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are, the Hydro Regional Manager on the Upper Spokane, the Upper Spokane plant personnel, GPSS Engineering, GPSS Construction and Maintenance, and Power Supply. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

This project will need to be sequenced with several other projects that are in process including crane overhauls and Unit 3 & 4 overhauls.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed using project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

3.2 Provide and discuss the governance processes and people that will provide oversight

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

3.3 How will decision-making, prioritization, and change requests be documented and monitored?

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Nine Mile Powerhouse Roof Replacement project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Nine Mile Powerhouse Roof Replacement

Signature:	Ryan Bean Digitally signed by Ryan Bean Date: 2022.08.31 11:04:24 -07'00'	Date:	
Print Name:	Ryan Bean		
Title:	Plant Manager		
Role:	Business Case Owner		
Signature:	Alexis Alexander Digitally signed by Alexis Alexander Date: 2022.09.02 16:13:32 -07'00'	Date:	
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Nine Mile Units 3 & 4 Controls Upgrade

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Nine Mile Units 3 and 4 controls were installed in the early 1990's and are at the end of their intended life. There is an increased likelihood of forced outages and subsequent loss of revenue and reliability due to their age. Nine Mile Units 3 and 4 controls are obsolete, unsupported and in overall poor condition; the switchgear floor is overloaded which is structurally unsafe. The recommended solution is to mechanical overhaul the units including installing new Francis Runners, new downstream water lubricated bearing and pedestal, new combination thrust/guide bearing with thrust shaft, and refurbishment of the wicket gate stems and all operating components**.** The original plan anticipated TTP of $2M in 2023 for Unit 3, however, due to resource constraints, and other higher priority projects within GPSS that demanded the same resources as this business case, work has been pushed into 2024 and beyond.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Capital spending levels are reviewed by the project steering-committee. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, the Project Steering Committee agrees on submitting funds requests or requests for release, if necessary. Those forms are signed by the Director and submitted to the company's Capital Planning Group (CPG) for funding consideration. See forms attached for 2023.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no offsets expected as a result of this project.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X DocuSigned by: Micheal Truex 30401E01AC1543C...

DIRECTOR SIGNATURE:

X DocuSigned by: David Howell 8A3FC650718B488...

Nine Mile 3 & 4 Controls Upgrade

EXECUTIVE SUMMARY

PROJECT NEED: Nine Mile Units 3 and 4 controls were installed in the early 1990's and are at the end of their intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability. During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due their age and current condition. The switchgear floor is overloaded which poses a safety risk. In 2010, the switchgear floor was found to be inadequate for any loading above and beyond what it is currently supported, and partially replaced during the Unit 1 and 2 replacement project. The re

EXECUTIVE SUMMARY

PROJECT NEED: There are a multitude of mechanical issues with Nine Mile Unit 3. The original Unit 3 was replaced with a new American Hydro unit in 1995. Unit 3 experienced cracked buckets on the runners in 2010. This was found to be due to heavy wear due to erosion from sediment and cavitation damage. The cracks were repaired; however, the sediment wear has continued, and bucket failure is anticipated. The installed roller guide bearing also does not provide the thrust bearing support it was designed to, causing the upstream generator guide bearing to take the entire thrust loading of the machine. This condition puts increased stress and wear on the generator bearings and increases the risk of failure. During the 2018 Maintenance Assessment, this bearing was identified as high risk due to its current condition.

RECOMMENDED SOLUTION: The recommended solution is to mechanical overhaul the Unit including installing new Francis Runners, new downstream water lubricated bearing and pedestal, new combination thrust/guide bearing with thrust shaft, and refurbishment of the wicket gate stems and all operating components

ALTERNATIVES CONSIDERED:

- Alternative 1: Do-nothing and continue to repair the current system under O&M.

COST OF RECOMMENDED SOLUTION: The estimated cost of the project is $6,500,000

ADDITIONAL INFO: Operating Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES). This alternative would provide a lasting solution to the problems outlined above and avoid a costly unanticipated failure. If left unaddressed, the Unit is likely to experience bucket or bearing failure.

minder of the floor will need to be replaced to ensure adequate floor loading can be achieved.

RECOMMENDED SOLUTION: A controls upgrade including speed controllers (governors), voltage controls (automatic voltage regulator or AVR), primary unit control system (i.e., Unit PLC), and the upgraded protective relay system is needed on units 3 and 4. Included in the scope of this project is replacement of the switchgear floor inside the Nine Mile powerhouse that will be utilized for relocation of the unit controls and voltage regulation equipment.

ALTERNATIVES CONSIDERED:

- Alternative 1: One alternative considered is to replace the electrical equipment but not upgrade the floor.
- Alternative 2: A second alternative considered was to do-nothing

COST OF RECOMMENDED SOLUTION: The cost of the solution is estimated to be about $4,125,000 per unit at this time; total of $8,250,000.

ADDITIONAL INFO: The completion of this project will reduce maintenance costs and improve reliability delivered to Avista's customers as upgrading the controls, monitoring, and protection will reduce unplanned outages. This solution will address issues of obsolescence, increased likelihood of unplanned outages, and performance needs to work with the new dynamics of modern systems. This includes integration of intermittent resources, reserves, frequency and voltage response, and the ability to adapt these controls and protection devices as the larger grid continues to evolve. If this business case is not approved the risks above would continue as the asset condition continues to decline.

Nine Mile 3 & 4 Controls Upgrade

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Kristina Newhouse Ryan Bean	Initial submission	7/2/2019	
2.0	Kristina Newhouse	Updated to 2020 template	7/31/2020	
3.0	Kristina Newhouse & PJ Henscheid	Updated to 2022 template and modified budget to align with improved estimates	8/23/2022	
4.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 2,100,000	$ 0
2025	$ 2,300,000	$ 0
2026	$ 2,250,000	$ 0
2027	$ 250,000	$ 8,250,000
2028	$ 0	$ 0

The business case will include 2 projects, one for Unit 3 and another for Unit 4. Design and Construction for each project take place over 3 years with the design of unit 4 starting during construction of unit 3. Each project with be transferred to plant at the completion of construction

Nine Mile 3 & 4 Controls Upgrade

Project Life Span	4 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Planning
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Nine Mile 3 & 4 Controls Upgrade

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

The problem is that Nine Mile Units 3 and 4 controls are obsolete, unsupported and in overall poor condition; the switchgear floor is overloaded which is structurally unsafe.

1.2 Discuss the major drivers of the business case

The major driver of this business case is Asset Condition. There have been unit outages that were specifically taken to address problems associated with the existing control and protection equipment. Problems with the governor and wicket gate actuating mechanisms continue to affect unit reliability. The current governor system is undersized to handle the required load, causing startup and speed control issues.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due their age and current condition. This equipment is at the end of its intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability.

Upgrading the speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e., PLC), and the protective relay system will address issues of obsolescence, increased likelihood of unplanned outages, and performance needs to work with the new dynamics of modern systems. Also, the switchgear floor is inadequate to support additional loading for new equipment to be place. Replacing the remainder of the floor will ensure adequate floor loading can be achieved.

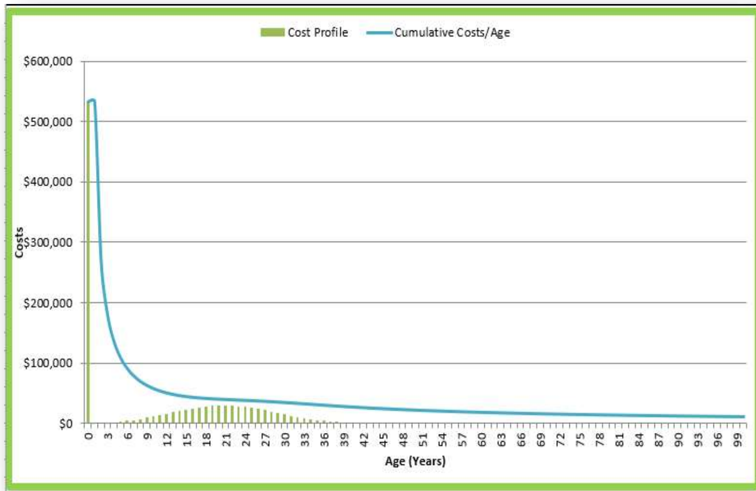
1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. Avista Strategic Goals

Replacing obsolete and problematic control equipment on unit 3 and unit 4 will increase reliability and efficiencies at Nine Mile HED. This program safely, responsibly, and affordably improves our customers' lives through innovative energy solutions.

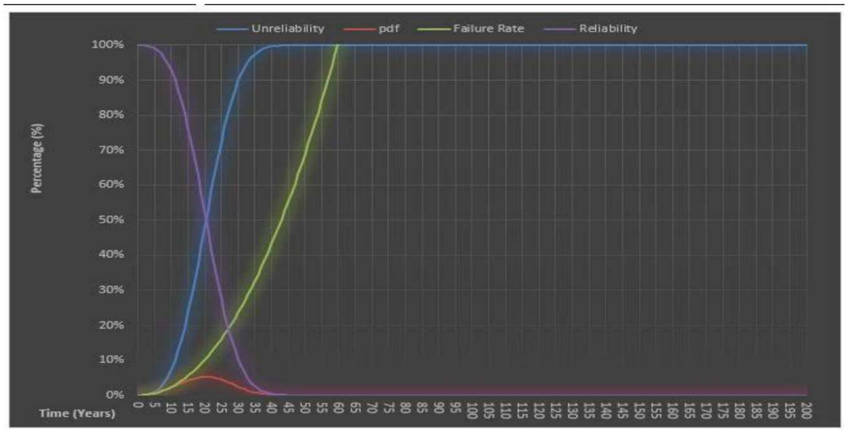
Customers benefit in that it will allow Avista to economically optimize an existing asset to provide energy and other energy related products.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due their age and current condition. This equipment is at the end of its intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability.



Please see the graphs which illustrate the Lifecyle Cost Analysis that was done as part of the 2018 Maintenance Assessment.



[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: The recommended solution is to replace unit control, monitoring, and protection systems, and it includes replacement of the switchgear floor to adequately support the new equipment to be placed. In addition to addressing issues of obsolescence and increased likelihood of unplanned outages, replacement of these key systems addresses the performance needs to work with the new dynamics of the systems today. This solution solves the problem described above through the integration of intermittent resources, reserves, frequency and voltage response, and the ability to adapt these controls and protection devices as the larger grid continues to evolve.

In Scope: The requested capital costs will cover design (contract labor), material, factory acceptance testing (contract labor), installation (AVA labor), and commissioning. To accomplish project objectives that will improve unit response, operating flexibility, and reliability, the following components will be considered: governor and governor controls, generator excitation system and AVR, protective relays, and unit controls, Unit 3 & 4 switchgear. The objective is to ensure system compatibility with current standards and improve system reliability. Flooring upgrades are limited to demo and reinforced (approx. half of the switchgear floor, ballpark 30'x50')

Out of Scope: Disassembling or pulling poles on the generators; generator work is limited to housekeeping**,** switchgear replacement.

Assumptions: Equipment will not be replaced in-kind: motor operated governor will be replaced with a hydraulic system; the current Bailey controls hardware will be replaced with a PLC; new Unit 3 & 4 switchgear will be relocated to the new switchgear floor (no modifications to the existing switchgear location will need to be made once the old switch gear is removed)

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- CARS (Capital Additions and Retirement) form which documents added and removed assets associated with Avista's facilities. This document helps Avista maintain accurate continuing property records.

- The 2018 Hydro Generation Condition & Risk Assessments, is referred to as the "2018 Assessment." Early 2018 GPSS-Hydro department undertook an initiative to revamp their maintenance programs. This included the 2018 Assessment, which was conducted in the hydro plants and incorporated both Risk Assessments and Condition Assessments. Teams consisting of representatives from the Mechanic, PCM Tech, and Electric Shops, as well as Spokane River Hydro, Clark Fork River Hydro, and Maximo teams were formed and tasked with performing a condition and risk based assessment for assets in all of Avista's hydro facilities. Additional details may be found in the "2018 Hydro Asset Management Program Directory". The full reference is provided below:

  The Condition Assessments were based on the CEATI hydroAMP 2.0 guide. The database developed during the 2018 assessment has been used to create business information tools to identify and analyze equipment strategies to be used by GPSS for making business decisions.

  The purpose of the Risk Assessment was to identify the environmental, financial, and safety risks associated with each asset and what possible consequences might result from an asset failure. Consequences were framed within the Avista Business Risk Matrix. Financial risks might include lost generation during an outage. Probabilities were then estimated as an answer to the following question: Given an asset failure, what is the probability that a particular, potential consequence will actually occur? As an aid to this process, probabilities were selected from a menu of specified probability levels. Results of the Risk Assessments have been used to estimate asset risk costs. Risk cost is the product of the Failure Rate, Potential Consequence of failure. This risk cost is a probable dollar value associated with Avista's exposure risk of each asset.

  The results of the 2018 Assessment have been used to develop Asset Management Plans (AMPs) and a Risk Based Investment Planning (RBIP) tool. AMPs have been developed for a number of the asset classes, such as the generators, turbine runners, GSUs, trash rakes, etc. The AMPs outline capital and maintenance strategies. A primary purpose of the RBIP tool is to bring a risk-based perspective to the capital budget process.

  Reference - Avista Utilities, "2018 Hydro Asset Management Program Directory", Avista Utilities GPSS Dept., March 15, 2019

  Additionally, the following files from the 2018 Maintenance Assessment can be found at (c01m114) G:\Generation\Asset Management\GPSS Condition Assessment Forms and References\Condition Assessment - NM

1. Nine Mile Hydro AMP 041912.xlsx file
2. NM Lifecycle Cost Calculator 061918.xlsx

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

- Risk Cost calculation from GPSS Asset Management Group: Risk cost is the product of the Failure Rate, Potential Consequence of failure, and the Probability of experiencing the potential consequence in the event of a failure. This risk cost is associated with the probable dollar value associated with Avista's exposure risk of each component. This exposure risk includes the cost of anything that threatens the company, including costs associated with a probable failure of the components (potentially including replacement, refurbishment, or lost generation costs), safety risks associated with normal operation or replacement actions, and probable environmental risks associated with the asset, and at times other costs such as public perception risk mitigation activities. While the company may not be able to shelter itself from risk completely, there are ways it can help protect itself from the effects of business risk, primarily by adopting a risk management strategy as a part of the asset management program. Risk costs not only take account for the exposure risk for an asset but also the criticality (or importance of an asset) and its' current condition. Risk costs are somewhat analogous to insurance premiums. They represent an annual cost, but the year-to-year costs vary with the condition of the assets. If we total the risk costs for all of our assets for the next year, the company would need to have monies set aside for that year to cover the costs associate with the assets that fail that year.\

$$\begin{aligned} &\mathit{Annual\ Risk\ Cost} \\ &= [\mathit{Probability\ of\ Failure}\ (\mathit{that\ year})] \times [\mathit{Consequence}\ \$] \\ &\times [\mathit{Likelihood\ of\ actually\ experiencing\ that\ consequence}] \end{aligned}$$

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	N/A	$0	$0	$0	$0	$0

While the generator is capable of producing energy with existing systems, this solution requires maintenance of old systems that are no longer supported by the original manufacturer and there is some question on parts availability. Additionally, trained personnel available to work on these older systems are becoming scarce and formal training is no longer available. For reasons of obsolescence, inadequate system performance, and increasing maintenance demands, this option is not the preferred option. This project is a replacement of EOL technology and controls equipment that is no longer supported by

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

industry R&D and necessary support infrastructure to ensure reliable, affordable, and safe generation, production, and distribution of power.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	N/A	$0	$0	$0	$0	$0

Estimated indirect savings and/or productivity gains and associated benefits have not been quantified at this time; however, as applicable, please see the referenced Risk Based Investment report (see Section 2.2) for additional information.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: The recommended solution is to replace unit control, monitoring, and protection systems and upgrade the switchgear floor. We cannot continue to operate units 3 and 4 at Nine Mile HED and expect the same results as when the controls were installed over 20 years ago. Technology has improved and the expectations for automation and monitoring continue to increase. The installation of new controls and protection will also provide increased visibility into the systems allowing better remote monitoring and troubleshooting. If we do not invest and take care of these two units, they will continue to be unreliable and fall further behind in technology that other upgraded units operate with.

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[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Alternative 1: Replace Unit Control, Monitoring, and Protection Systems Only, Do Not Replacing Flooring; $7.25M

This Alternative would replace unit control, monitoring, and protection systems. This alternative would not upgrade the switchgear floor. This alternative is currently in engineering evaluation to determine if the new controls equipment can be functionally located somewhere other than the switchgear floor. There is still the potential that this alternative could be feasible, thus saving ~$1M in total project cost, but will not be determined until preliminary design is complete.

Alternative 2: Do Nothing; $0 in Capital

This alternative would leave the equipment as-is. Replacing the equipment is critical due to the extensive age of the various systems and the difficulty to upgrade only a portion of the technology as new technology is incompatible with the obsolete technology.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

A successful investment to upgrade the Nine Mile 3 & 4 Control Monitoring, and Protection systems would be measurable by Future Maintenance Assessments that would show an improved condition and reduction in risk,

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

The business case will include 2 projects, one for Unit 3 and another for Unit 4. Design and Construction for each project take place over 3 years with the design of unit 4 starting during construction of unit 3. Each project with be transferred to plant at the completion of construction

☒Timeline is Known

- **Start Date:** 2023
- **End Date:** 2025

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/Governance Team

The steering committee will minimally consist of the Controls Engineering Manager, the Electrical Engineering Manager, The Mechanical Engineering Manager, The protection Engineering Manager, the Protection Control Meter Technician Foreman, and the Spokane River Plant and Operations Manager.

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Nine Mile Unit 3 & 4 Control Upgrade business case the and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-09-2023 | 7:30 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alexis Alexander EA27BABA767E467...	Date:	Aug-26-2023 | 1:30 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		
Signature:	NA	Date:	
Print Name:	NA; Michael Truex is currently on the steering committee		
Title:	NA		
Role:	Steering/Advisory Committee Review		

NM Units 3 – 4 Controls Upgrade

1.0 CHANGE REQUEST #1 – FEBRUARY 2023

Previous Requests	Requested	Approved
5-Year Plan	$	$0
In Year 2023	-$2,250,000	$1,000,000

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

MM-YYYY	LTD Spend	Current 2023 Approval	2023 Requested Change	Proposed 2023 Total
Feb 2023	$25,340	$3,250,000	-$2,250,000	$1,000,000

Type of Change	In-year Update
Primary Reason for Change	Timing Change, Internally Driven
Response needed by	2/15/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

GPSS Controls Engineering workforce has experienced a reduction; there is not enough manpower to work on this project and the other higher priority projects at the same time.

This project will be placed on hold until after the Cabinet Gorge Station Service project is complete which is expected Q4 2024.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

N/A

1.1.3 Please reference analysis or information that support the problem and attach to this document.

N/A

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented, including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

N/A

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

N/A

NM Units 3 – 4 Controls Upgrade

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

N/A

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The justification narrative is still valid given the nature of this change.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
Kristina Newhouse	BC Owner		
Alexis Alexander	BC Sponsor		
	FP&A		

1.0 CHANGE REQUEST #2 – 2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
Aug 2023	*Timing Change, Internally Driven*	2	$1,000,000	-$500,000		$500,000
Feb 2023	*Timing Change, Internally Driven*	1	$3,250,000	-$2,250,000	$1,000,000	$1,000,000
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
Aug 2023	Timing Change, Internally Driven	0	0	$8,250,000	$5,600,000
Feb 2023	Timing Change, Internally Driven	0	0	$8,250,000	$8,250,000
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This should not be considered approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2022	$1,000,000	$100,000	0	0		
2023	$3,250,000	$500,000	0	0		
2024	$2,100,000	$2,500,000	0	0		
2025	$2,300,000	$2,500,000	0	0		
2026	$2,250,000	0	0	0		
2027	0	0	0	0	$8,250,000	$5,600,000

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

2028						

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The project engineering progress has experienced schedule delays due to resource constraints with other higher priority projects in GPSS namely Nine Mile Unit 3. Though there are some Controls components related to the mechanical overhaul of Unit 3 at Nine Mile, they are small and not terribly costly. Work for this project in outer years will ramp up after Nine Mile Unit 3 has been commissioned, is back online, and adequate resources are available to complete the work.

With regard to the revisions to the Transfer to Plant amounts, since establishing this project in 2022, it has been decided that the work will be phased because a portion of it directly impacts the Unit 3 Mechancial Overhaul project. Splitting up the project (or phasing the work) means that portions of it will be placed into service at different times – specifically as it relates to Unit 3 and Unit 4 individually. To be more specific, the Unit 3 governor will be commissioned and included in the Unit 3 Phased work that coincides with Unit 3 Mechanical. The Unit 4 governor will not be commissioned until 2025 along with Phase II of this program.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature
Kristina Newhouse	BC Owner	
Alexis Alexander	BC Sponsor	
	Steering Committee (If applicable)	

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Noxon Rapids Spillgate Refurbishment

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

At the time the rate case was filed in late 2021, it was anticipated that the NR Spillgate rehabilitation project would be farther out on our 5-10 year plan. Early design efforts determined that material condition required earlier, smaller scale, remediation efforts. During preliminary design for that larger effort, it was determined that in "normal conditions" the spillgate loadings were being stressed. Therefore, in 2022 a project was opened to add additional structure elements to the gates to address the imemdiately identified structural liabilities while we waited for the completed seismic study and flood studies. This preliminary work was completed in 2023. The variance is due to the fact that this remediation effort came about, and was completed, all in the time since we submitted our original capital plan.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This scope does not represent a significant overrun to the intial planned spillgate remediation effort. This spend and resulting TTP represents a change in the type of work we were able to complete and put into service during this design phase. While we wait for seismic and flood study results, we have been able to identify, improve, and add reliability to our assets, providing an immediate benefit to our customers.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

Offsets are not an applicable byproduct of this scope of work. There are no operating costs that will be remediated by the ultimate spillgate enhancements made to the dam and there are no additional labor efforts associated with the interim improvements made for normal conditions.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Michael Truex
Michael Truex (Feb 27, 2024 16:23 PST)

Michael Truex
Michael Truex (Feb 27, 2024 16:23 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 28, 2024 10:09 PST)

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Outage Management System and Advanced Distribution Management System

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The OMS/ADMS business case is replacing Avista's in house developed and end of life Outage Management Tool with an industry standard Advanced Distribution Management System. An ADMS system will improve operational awareness and grid management capabilities enabling real time outage restoration to improve field and office worker productivity.

The business case was expected to transfer to plant $10M and ended up transferring 4.65M, or 5.35M less than expected. This initial $10M amount was estimated prior to the start of the business case and was developed based on the best estimates available at the time. Since that time the project team has learned more about the timeline, schedule and cost of the product implementation resulting to changes in TTP amounts and timelines. In addition, the start of work in the OMS/ADMS business case was delayed due to the RFP selection process and contract negotiations taking longer than originally planned. This resulted in a change of the transfer to plant date for the main implementation of the product from 2023 to 2025. The business case was able to release capital funding in 2023 because of the delay in the project start and spend.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The Business case revised the TTP amounts for 2024 and 2025 reflecting a change in the 2023 TTP from 10M to 3M in the Business Case Justification Narrative resubmitted in 2023. Please see the attached Narrative as "OMS ADMS Business Case Justification 2021-2028.pdf.

At the end of 2023, network hardware had been installed and the program team was not aware that this could be used and useful and after further review a determination was made that it was in fact used and useful. The program team had already planned a separate project for these assets totaling approximately 1.2M that was planned to TTP in 2025, however this TTP occurred early in December 2023 as the systems were now in use.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

Offsets remain the same as noted in the OMS/ADMS business case updated in July 2023.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:	DIRECTOR SIGNATURE:	DIRECTOR SIGNATURE:
Mar-07-2024 | 8:38 AM PST	Mar-07-2024 | 11:24 AM PST	Mar-07-2024 | 1:39 PM
X DocuSigned by: Stephanie Myers 571A8FBE3364417...	X DocuSigned by: Hossein Nkdel E4E2D9C7EE4747F...	X DocuSigned by: Mike Magruder 13E5B221EFEE401...

Outage Management System and Advanced Distribution Management System (OMS/ADMS)

EXECUTIVE SUMMARY

Avista's Outage Management Tool (OMT) is an in-house developed custom application that supports electric outage analysis, management, and restoration. OMT is a mission critical system which provides the functionality to manage the electric distribution grid, the overall life cycle of electric outages and the restoration processes for the Washington and Idaho service territories. The OMT application and data model were developed by Avista at a time when commercial outage management software was not available, have been used for nearly two decades and are approaching technology obsolescence. The existing Geographic Information System (GIS) operating platform on which OMT is built is scheduled by the vendor for end of life in 2028 and is recommended for replacement in the Atlas business case. The OMT application is showing increasing signs of fatigue (such as system instability during storm scenarios) and the loss of OMT would mean significant risks, increased costs, and customer benefit impacts which are detailed in the narrative below. The loss of OMT is rated 6th on Avista's corporate risk register, which means replacing it with a modern application is a top priority.

OMT works in synchronization with Avista's Distribution Management System (DMS), in order to monitor and control Avista's electric distribution network efficiently and reliably. The DMS is a commercial application used to monitor and control the portion of the distribution grid that is equipped with "smart grid" technology that enables remote monitor and control. It relies on Geographic Information System (GIS) data to determine the current operating state of the distribution system, which is provided via an outdated, custom-built data model import tool and OMT integration. Frequent integration failures result in the two systems being out of synch with each other, requiring a significant amount of manual intervention to resolve each week. The DMS marginally meets the current business needs but will not meet future needs for additional distribution grid automation and Distributed Energy Resources requirements to meet customer choice and Clean Energy Transformation Act requirements.

Avista foresees a future utility architecture that bridges use cases across Customer, Grid, Operations, and Utility Enterprise domains. This future will require a technology platform that enables the integration of these domains. The industry standard for this platform is an Advanced Distribution Management System (ADMS). Replacing Avista's OMT and DMS with a single ADMS will achieve improved operational awareness and grid management capabilities, enable real-time automated outage restoration, enable real-time grid optimization and performance, improve field and office worker productivity, and provide the ability to reengineer work processes and methods to support the continuous improvement of Avista's Distribution System Operator program. An ADMS solution incorporates industry best practices for optimized workflow, software performance and reporting which will provide Avista with the ability to respond to more stringent and detailed regulatory compliance reporting requirements, such as those for Wildfire Resiliency and the Clean Energy Transformation Act. A modern ADMS also enables the ability to deliver more geographically specific Estimated Restoration Time (ERT) information to electric customers during outages. The improved ERT accuracy and restoration status for customers will improve customer confidence in the information which will reduce the number of calls received by our customer service representatives, as well as call durations.

The estimated project cost is $49M over a four-year planned project duration. Because of the importance of this project, and the fact that the primary reason ADMS projects fail or run over time and over budget is due to the inability to create and maintain an accurate distribution grid data model, initial development work on the data model was started in 2022. The bulk of the ADMS implementation effort is scheduled to start in Q2-2023, with a three month Phase 0 effort focused on validating the data model and identifying technically challenging use cases by running a series of tests utilizing the out-of-the-box software, using Avista's distribution grid data model and Avista's realtime distribution grid simulator. The Phase 0 effort will enable the project to efficiently proceed into the Phase 1 design and implementation effort in Q3-2023 with reduced risk to scope, schedule, and budget, improving the likelihood of completing the project as planned.

Since this is a multiyear project, the work needs to start in 2023 as scheduled in order to have the ADMS fully operational before the OMT operating platform is no longer supported and to meet increasing customer and regulatory expectations which cannot be achieved with the legacy OMT and DMS applications. Avista needs to proceed with the work now in order to be ready for the future, in a similar way to how planning is done for future power needs; i.e., we don't wait until we run out of power to build new generation. It would not be prudent to wait until after our current system completely fails to meet our needs to start an ADMS project.

A Request for Proposal (RFP) was released to the industry leading ADMS software vendors in Q3-2022. From that process, four vendors responded which were thoroughly evaluated and a recommendation to proceed with General Electric (GE) was made to executive leadership to proceed into contract negotiations with the successful bidder. The recommendation was approved, and contract negotiations were complete in Q1-2023.

VERSION HISTORY

Version	Author	Description	Date
1.0	Mike Littrel	Initial draft of business case	04/2017
2.0	*Mike Littrel*	*Updated business case format*	*07/2020*
3.0	*Mike Littrel*	*Updated program details and budget*	*07/2021*
4.0	*Mike Littrel*	*Updated program details and budget*	*08/2022*
5.0	*Mike Littrel*	*Updated program details and budget*	*04/2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	

Outage Management System and Advanced Distribution Management System (OMS/ADMS)

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$13.75M	$1.8M
2025	$9.6M	$24M
2026	$7.4M	$6.8M
2027	$4.5M	$4M
2028	$0	$0

Project Life Span	*4 years*
Requesting Organization/Department	Enterprise Technology
Business Case Owner | Sponsor	Mike Littrel | Mike Magruder, Hossein Nikdel
Sponsor Organization/Department	Energy Delivery Technology Projects
Phase	Execution
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Outage Management System and Advanced Distribution Management System (OMS/ADMS)

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Avista's current Outage Management Tool (OMT) has been used for nearly two decades and is approaching obsolescence. The technology is becoming more and more difficult to configure to meet the changing business needs and has exceeded its useful life. The software has already undergone two major conversions to extend the life to this point. Both changes achieved their goals; however, the code is now more fragile which has increased the complexity of supporting OMT.

Additionally, the existing system is custom built and requires continual maintenance and support by internal staff whose skillset is becoming scarce, as the fundamental code and architecture is complex and outdated. OMT does not have the full complement of functionality required to meet current and future needs of the Distribution System Operators as they respond to an increasingly complex and dynamic electric distribution grid. Outage incident processing performance can be very slow and unstable during high-volume outage conditions (storms), particularly in field division offices, impacting the ability to restore service quickly. When a new configuration request is surfaced, the change cannot always be implemented, as the custom code and architecture may not allow it. The existing operating platform used by OMT is currently scheduled for end of life in 2025.

The existing OMT workflow does not include a fully digital workflow for the field personnel who are responding to outage scenarios. This lack of a digital workflow creates gaps in situational awareness for both the field personnel and the Distribution Operators who are planning and coordinating the restoration effort. These gaps can lead to potential safety hazards and inefficiencies in the restoration process. It also creates gaps in the level of detail collected during the damage assessment and restoration activities. These details are becoming increasingly important to be able to report on for programs such as Wildfire Resiliency. Modern ADMS platforms include a fully digital workflow which enable both field and office personnel to have access to the same information and receive near real-time status updates during an outage event, improving safety and efficiency. A digital workflow also ensures that the damage and repair information is captured accurately and completely through the use a rule driven forms.

Switching (the process to de-energize a section of the electric grid for construction, maintenance, or repair) is another area for significant improvement in both effectiveness and safety. Currently switching plans are developed in a Word document through conversations with the people involved (Area Engineer, Foreman, Distribution Operators, etc.) and the plan steps are executed manually on the day of the planned switching activity. An ADMS provides a fully digital and integrated process for switch plan development, study mode, and execution of the switching activity. This fully digital process ensures that the switching meets all electric grid and safety requirements by monitoring each step of the plan against the actions taken and alerting the personnel if a step is missed, a step is invalid, or an error is made during the switching process. The switch plans are also stored in an online library for quick reference in order to have a highly reproducible process for future switch plans.

The existing Distribution Management System (DMS) has several challenges which the ADMS will address. First, the DMS relies on GIS data to determine the current operating state of the distribution system which is provided via an outdated, custom-built OMT integration. Frequent integration failures result in the two systems being out of synch with each other, requiring a significant amount of manual intervention to resolve each week. The DMS marginally meets the current business needs but will not meet future needs for additional distribution grid automation and Distributed Energy Resources requirements to meet customer choice, and Clean Energy Transformation Act requirements.

1.2 Discuss the major drivers of the business case.

Avista can gain significant operations and business advantages by replacing the OMT and the DMS with an ADMS. A modern ADMS can address many of the issues currently faced by Distribution System Operators and Electric Operations field personnel. The benefits of an ADMS fully integrated with other enterprise systems along with optimized business processes include; improved outage analysis and restoration capabilities, improved safety, improved status information to customer facing systems, and improved system reliability and dependability. Avista responds to multiple major storm events per year. An ADMS with a fully digital workflow has the potential to reduce the labor costs of these major events by at least 10%. Based on actual storm costs for 2017-2021 that's an average savings of $340,379 per year (see table below) split 75% capital and 25% O&M.

Outage Management System and Advanced Distribution Management System (OMS/ADMS)

Accounting Year	Summary Exp Category	Sum of Actuals	with ADMS	10% Savings
2017	Labor	$3,357,066	$3,021,360	$335,707
	Non-Labor	$4,460,419	$4,460,419	$0
2017 Total		**$7,817,485**	**$7,481,778**	**$335,707**
2018	Labor	$2,227,664	$2,004,897	$222,766
	Non-Labor	$2,649,948	$2,649,948	$0
2018 Total		**$4,877,611**	**$4,654,845**	**$222,766**
2019	Labor	$2,366,126	$2,129,514	$236,613
	Non-Labor	$5,341,119	$5,341,119	$0
2019 Total		**$7,707,245**	**$7,470,633**	**$236,613**
2020	Labor	$4,139,030	$3,725,127	$413,903
	Non-Labor	$14,288,254	$14,288,254	$0
2020 Total		**$18,427,284**	**$18,013,381**	**$413,903**
2021	Labor	$4,929,088	$4,436,179	$492,909
	Non-Labor	$14,398,068	$14,398,068	$0
2021 Total		**$19,327,156**	**$18,834,248**	**$492,909**
Annual Average		**$11,631,356**	**$11,290,977**	**$340,379**

A fully integrated ADMS provides capabilities that include: (1) a platform that integrates numerous utility systems to achieve improved operational awareness and grid management capabilities, (2) expanded real-time automated outage restoration, and (3) enables real-time optimization of electric distribution grid performance.

While improved customer experience is difficult to quantify, it is perhaps the most important business reason for justifying a new ADMS. During major outage event situations, the ability to communicate timely, accurate and consistent status of outages and estimated restoration time is of paramount importance to customers. Whether the customer hears directly from the utility, the media or a public agency, the information about the outage needs to be consistent. An ADMS is that vehicle to provide this timely, accurate and consistent information to customers.

Significant customer value from other corporate initiatives will be at risk if Avista lost the OMT and/or DMS capabilities and did not have an ADMS in place. This value is at risk if the ADMS project does not occur (or is delayed until OMT/DMS failure) because the Advanced Metering Infrastructure (AMI) meters simply provide near real-time data, they do not perform the analytics or initiate the optimization functions that produce the customer benefit. That work is currently accomplished by custom functionality within OMT and DMS, which would become native functionality within an ADMS. Some examples of these customer values from the August 2020 Avista Utilities Advanced Metering Infrastructure (AMI) Project Report include:

Benefit	Average Annual Customer Value
Early Outage Notification	$4,005,827
More Rapid Restoration	$2,269,968
Avoided Single Lights Out	$289,723
Reduced Major Storms Cost	$327,566
Conservation Voltage Reduction	$2,108,817

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The OMT application and data model have been used for nearly two decades and are approaching technology obsolescence. Continuing to utilize OMT would continue to create Operating and Maintenance cost pressure while also creating risks of system failure during times of high demand (storms). Additionally, any investment in the current system is a sunk cost, as the system is limited in the additional functionality it can provide to our staff as they respond to electric customer outages on an increasingly complex distribution system and the underlaying platform in schedule for end-of-life in 2025. The current system is highly customized making it increasingly difficult to integrate with newer enterprise applications. OMT is a cornerstone to Avista's ability to manage the overall cycle of the electric outage and restoration processes for the Washington and Idaho electric service territories. If it is not replaced prior to system failure, it would likely double the amount labor required to complete the restoration efforts, while also increasing public safety risks and lowering customer satisfaction. Based on a five-year average of actual storm labor costs for 2017-2021 that's an addition cost of $3,403,795 per year (see table below) split 75% capital and 25% O&M. The costs and risks would continue to accumulate after the storm as daily operations would be impacted for the duration of an OMT system failure. The Avista Risk register has the impact range of an OMT system failure set at $1.0M - $10.0M.

Outage Management System and Advanced Distribution Management System (OMS/ADMS)

Accounting Year	Summary Exp Category	Sum of Actuals	OMT/DMS Failure	Annual Cost Increase
2017	Labor	$3,357,066	$6,714,132	$3,357,066
	Non-Labor	$4,460,419	$4,460,419	$0
2017 Total		**$7,817,485**	**$11,174,551**	**$3,357,066**
2018	Labor	$2,227,664	$4,455,327	$2,227,664
	Non-Labor	$2,649,948	$2,649,948	$0
2018 Total		**$4,877,611**	**$7,105,275**	**$2,227,664**
2019	Labor	$2,366,126	$4,732,253	$2,366,126
	Non-Labor	$5,341,119	$5,341,119	$0
2019 Total		**$7,707,245**	**$10,073,372**	**$2,366,126**
2020	Labor	$4,139,030	$8,278,060	$4,139,030
	Non-Labor	$14,288,254	$14,288,254	$0
2020 Total		**$18,427,284**	**$22,566,313**	**$4,139,030**
2021	Labor	$4,929,088	$9,858,176	$4,929,088
	Non-Labor	$14,398,068	$14,398,068	$0
2021 Total		**$19,327,156**	**$24,256,245**	**$4,929,088**
Annual Average		**$11,631,356**	**$15,035,151**	**$3,403,795**

Since this is a multiyear project, the work needs to start as scheduled in order to have the ADMS fully operational before the OMT operating platform is no longer supported, and to meet increasing customer and regulatory expectations, which cannot be achieved with the legacy OMT and DSM applications. Avista needs to proceed with the work now in order to be ready for the future, in a similar way to how planning is done for future power needs; i.e., we don't wait until we run out of power to build new generation. Implementing an ADMS is a long-term project, so we don't want to wait until after our current system completely fails to meet our needs to start an ADMS project. If OMT is not replaced with a modern ADMS, the ability of Avista to meet current and future customer, regulatory, and compliance requirements will be at risk.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Having a modern ADMS will improve field and office worker productivity, provide more accurate data, and provide the ability to reengineer work processes and methods to support the continuous improvement of Avista's outage management and restoration program. It will also provide Avista with the ability to respond to more stringent and detailed regulatory compliance reporting requirements, enable effective operation of an increasingly complex and dynamic electric distribution grid, and deliver more accurate Estimated Restoration Time (ERT) information to electric customers during outages. The improved ERT accuracy and restoration status for customers will improve customer confidence in the information which will reduce the number of calls received by our customer service representatives, as well as call durations. The additional Distributed Energy Resource Management (DERM) functionality will support the long-term goals of the CEIP and Connected Communities project. CEIP and Connected Communities goals are described in more detail in section 2.6. A DERM provides the ability to actively manage energy resources such and wind, solar, batteries, etc. based on specific grid requirements in order to achieved goals such as increased distribution grid reliability.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Justification for system replacement is based on comprehensive assessments of technologies, processes and functions that were performed in 2015 by third-party consultants as part of an enterprise project planning process. The details of the assessments are available in the following supporting documents:

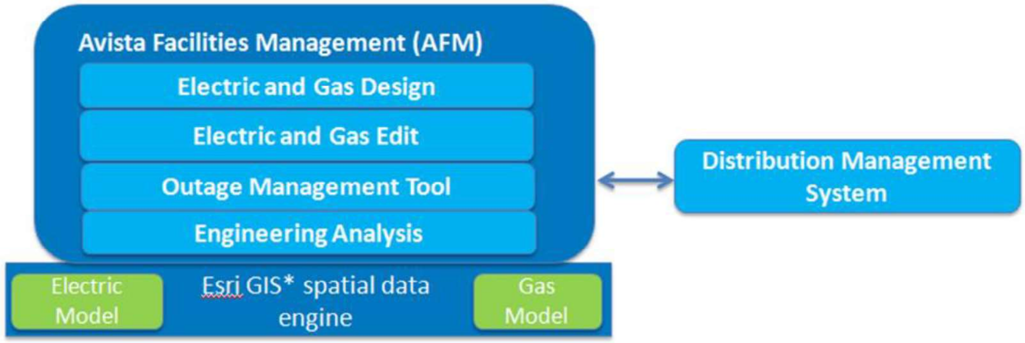
- Business Case
- Current State Report
- Future State Report
- Gap Analysis Report
- Industry Analysis Report
- Requirements Report
- Alternative Analysis Report

The Gap Analysis report includes a list of more than 30 gaps in the current state OMT/DMS applications that would be resolved/corrected with the implementation of an ADMS. The conclusion from the third-part consultant is:

> Avista can gain significant operations and business advantages by replacing OMT with a commercial OMS(ADMS). A new OMS(ADMS) can address many of the issues currently faced by dispatch and field personnel. Properly integrated with other systems with optimized processes, benefits to be realized include improved outage analysis and restoration capabilities, improved status information to customer facing systems, and improved system reliability and dependability. A new OMS(ADMS) will improve Avista's ability to respond to storm condition outages and restoration processes.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Outage Management System and Advanced Distribution Management System (OMS/ADMS)



*GIS - Geographic Information System

An Esri Geographic Information System (GIS) serves as the foundational data structure on which Avista Facility Management (AFM) applications, including OMT, are built or rely on. AFM is the system of record for spatial electric and gas facility data and provides the connectivity model to support OMT. The following is a brief description of AFM tools.

- Electric and Gas Edit are tools inherent in the system used for data edits prior to committing final data changes and additions.
- Outage Management Tool is an in-house developed application that supports outage analysis and management.
- Engineering Analysis is a commercial tool used for engineering analysis modeling.
- Distribution Management System is a commercial application used to monitor and control the portion of the distribution grid that is enabled with “smart grid” technology. It relies on the GIS data from OMT to determine the current operating state.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Avista foresees a future utility architecture that bridges use cases across Customer, Grid, Operations, and Utility Enterprise domains. This future will require a technology platform that enables the integration of these domains. The industry standard for this platform is an Advanced Distribution Management System (ADMS). Replacing Avista’s OMT and DMS with a single ADMS will achieve improved operational awareness and grid management capabilities, enable real-time automated outage restoration, enable real-time grid optimization and performance, improve field and office worker productivity, and provide the ability to reengineer work processes and methods to support the continuous improvement of Avista’s Distribution System Operator program. An ADMS solution also provides Avista with the ability to respond to more stringent and detailed regulatory compliance reporting requirements, such as those for Wildfire Resiliency and the Clean Energy Transformation Act. A modern ADMS also enables the ability to deliver more geographically specific Estimated Restoration Time (ERT) information to electric customers during outages. The improved ERT accuracy and restoration status for customers will improve customer confidence in the information which will reduce the number of calls received by our customer service representatives, as well as call durations.

The additional Distributed Energy Resource Management (DERM) functionality will support the long-term goals of the CEIP and Connected Communities project. CEIP and Connected Communities goals are described in more detail in section 2.6.

Option	Capital Cost	Start	Complete
Alternative 1 - Recommended Solution - Replace the custom OMT and DMS applications with an ADMS	$45.5M	04/2023	12/2026
Alternative 2 **–** Rewrite Custom OMT and keep DMS	Not Available	01/2023	06/2026
Alternative 3 - Continue to utilize the custom OMT and DMS applications until OMT runs out of support in 2025	$1.0M	06/2023	12/2025

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Detailed documentation from industry experts as listed in section 1.5 above, along with project costs from recent comparable projects at other utilities were used to determine the amount of the capital funds request and duration of the business case.

Avista released a Request for Proposal (RFP) in Q3-2022 to qualified ADMS software vendors and implementors. The responses were evaluated and scored in order to determine the best ADMS solution. The RFP results were provided to the project governance group for review and approval to proceed. The decision was made to proceed into contract negotiations with the recommended solution from GE, which provided both a rich set of features and functionality and a very competitive price. An initial Phase 0 engagement is

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

planned to refine the project's scope, schedule and budget which will reduce the risks of unforeseen issues impacting the project as work proceeds.

The funds in this business case will be utilized to fund the replacement of OMT and DMS with an ADMS. The project is estimated to have a four-year duration. Upon completion, the ADMS will fully replace both the existing Outage Management Tool and the Distribution Management System. The project

is scheduled to start in Q2-2023, with a three month Phase 0 effort focused on validating the data model and identifying technically challenging use cases by running a series of tests utilizing the out-of-the-box GE software, using Avista's distribution grid data model and Avista's real-time distribution grid simulator. The Phase 0 effort will enable the project to efficiently proceed into the Phase 1 design and implementation effort in Q3-2023 with reduced risk to scope, schedule, and budget, improving the likelihood of completing the project as planned. The project will ramp up during 2023, then have a levelized spend for multiple years over the duration of the project.

The Regulatory Affairs Team has reviewed the project and determined that an internal rate of return calculation would not be needed for this project.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

The ADMS project is not forecasting any direct offsets because there will be no staffing or software reductions as a result of this project.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$	$	$	$	$
O&M	N/A	$	$	$	$	$

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

Modernizing Avista's outage management software and business processes is anticipated to provide the following indirect labor savings from improved work efficiencies for Field personnel and Distribution Operations personnel who respond to electric outages. The five-year estimated saving (starting in 2025) is estimated to be $1.0M.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Outage Management System and Advanced Distribution Management System (OMS/ADMS)

These high-level estimated savings are based on a review of current and previous projects completed at Avista with a uniform efficiency value applied based on the types of applications deployed. The following are high-level estimates, and the Company does not currently have a way to track if these benefits will be realized.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Improved Storm Response	$	$255K	$255K	$255K	$255K
O&M	Field personnel	$	$80k	$80k	$80k	$80k
O&M	Distribution Operations Personnel	$	$120K	$120K	$120K	$120K
O&M	Improved Storm Response		$85K	$85K	$85K	$85K

OMS/ADMS Indirect Savings Estimates

Field Personnel Annual Indirect Offset Potential		
Estimated Number of Users	85	
Estimated Efficiency per User	15	minutes per incident
Estimated Usage Incidents per year	60	
Standard Hourly Labor Rate	$85.00	
Estimated Percent of Users in WA	75%	
Estimated Annual Indirect Labor Offset	**$81,281**	

Distribution Operations Annual Indirect Offset Potential		
Estimated Number of Users	10	
Estimated Efficiency per User	10	minutes per day
Estimated Usage Days per year	365	
Standard Hourly Labor Rate	$85.00	
Estimated Percent of Users in WA	75%	
Estimated Annual Indirect Labor Offset	$38,781	

Estimated Annual Indirect Labor Offset	**$120,063**

Improved Storm Response

Avista can gain significant operations and business advantages by replacing the OMT and the DMS with an ADMS. A modern ADMS can address many of the issues currently faced by Distribution System Operators and Electric Operations field personnel. The benefits of an ADMS fully integrated with other enterprise systems along with optimized business processes include; improved outage analysis and restoration capabilities, improved safety, improved status information to customer facing systems, and improved system reliability and dependability. Avista responds to multiple major storm events per year. An ADMS with a fully digital workflow has the potential to reduce the labor costs of these major events by at least 10%. Based on actual storm costs for 2017-2021 that's an average savings of $340,379 per year (see table below) split 75% capital and 25% O&M.

Estimated Annual O&M Indirect Labor Offset $85,095

Estimated Annual Capital Indirect Labor Offset $255,294

Accounting Year	Summary Exp Category	Sum of Actuals	with ADMS	10% Savings
2017	Labor	$3,357,066	$3,021,360	$335,707
	Non-Labor	$4,460,419	$4,460,419	$0
2017 Total		**$7,817,485**	**$7,481,778**	**$335,707**
2018	Labor	$2,227,664	$2,004,897	$222,766
	Non-Labor	$2,649,948	$2,649,948	$0
2018 Total		**$4,877,611**	**$4,654,845**	**$222,766**
2019	Labor	$2,366,126	$2,129,514	$236,613
	Non-Labor	$5,341,119	$5,341,119	$0
2019 Total		**$7,707,245**	**$7,470,633**	**$236,613**
2020	Labor	$4,139,030	$3,725,127	$413,903
	Non-Labor	$14,288,254	$14,288,254	$0
2020 Total		**$18,427,284**	**$18,013,381**	**$413,903**
2021	Labor	$4,929,088	$4,436,179	$492,909
	Non-Labor	$14,398,068	$14,398,068	$0
2021 Total		**$19,327,156**	**$18,834,248**	**$492,909**
Annual Average		**$11,631,356**	**$11,290,977**	**$340,379**

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternate 1 (Recommended) – Implement an ADMS - The current OMT has a recent history of performance challenges which may only be mitigated with considerable investment or replacement. Continuing to invest in a custom system with no vendor support is not a sustainable long-term solution. There are network management functionality limitations and performance related issues with the current data model that are addressed by a modern ADMS. The support by Esri for the current software solution will be ending in January 2025. Continuing to use OMT beyond that date would become increasingly costly and risky without an investment in an upgrade. Staying on the current platform version includes risks, such as:

- As the version goes out of support from Esri, Avista will not be able to receive patching from Esri to respond to cyber security vulnerabilities.
- Performance challenges and instabilities of OMT during major storm events will continue to exist because a GIS platform is not architected to handle the large volume of data and data changes that occurs during a storm event.
- Keeping OMT in the GIS environment rather than moving it to a separate ADMS platform, would cause the system to continue to be suspectable to configuration changes made to support GIS Edit functionality which has an inadvertent negative impact on OMT, which occurred in 2022.
- Continued integration failures between OMT and the DMS resulting in the two systems being out of synch with each other, requiring a significant amount of manual intervention to resolve each week.
- The DMS marginally meets the current business needs but will not meet future needs for additional distribution grid automation and Distributed Energy Resources requirements to meet customer choice Clean Energy Transformation Act requirements. A future DMS replacement project would be required to address these shortcomings.

- Having a modern, dependable outage management system is critical for Avista to provide safe and reliable energy for the customers. The ADMS project Request for Proposal (RFP) results received in late 2022 for Alternative #2 (Implement an ADMS) validate that the first costs of implementing an ADMS are comparable to an attempted rewrite of OMT, without the risks and limitations Alternative #1 and all the short and long term benefits of having a modern ADMS.

Alternative 2 – Rewrite OMT - Avista could endeavor to rewrite the current OMT application to function on the new Esri operating platform and data model. An initial effort estimate on this alternative indicates that it would have a lower first cost than implementing an ADMS however this alternative has several areas of high risk that would likely overshadow the initial costs savings. Examples include:

- Avista has made a corporate decision that it is not a software development company and will instead purchase and configure industry standard applications to reduce the risks and costs of owning and maintaining custom applications.
- OMT is a mission critical system. At the time it was originally developed by Avista there were no commercially available outage management applications that met Avista's requirements. That is no longer the situation.
- No other utility has written a custom OMT application using the new Esri operating platform. This first of its kind development effort has many unknowns that Avista would discover along the way likely increasing timelines, costs, and risks. Avista would also carry the sole responsibility

for resolving performance/accuracy/reliability issues that will inevitably crop up in production with a first-generation application.

- Keeping OMT in the GIS environment, rather than moving it to a separate ADMS platform, keeps the outage system closely coupled to the GIS data model. This will introduce new risks and complexities as Avista transitions to Esri's new data model in the next 3-5 years. Having a separate ADMS platform will isolate the ADMS from future Esri data model changes.
- Keeping OMT in the GIS environment rather than moving it to a separate ADMS platform, would cause the system to continue to be suspectable to configuration changes made to support GIS Edit functionality which has an inadvertent negative impact on OMT. A change made in 2022 to support Edit introduced a data problem which did not reveal itself for several months, but eventually lead to a failure in OMT during an outage event.
- A rewrite of the existing functionality would not provide the improved safety, performance, and data accuracy features that a fully digital workflow through and ADMS would provide. Because a GIS environment is not built for the high volume of data and high rate of data change that is required during outage scenarios. This leads to slow performance as the volume of data and increases. This performance issue would not be overcome with a rewriting of the OMT application, because the underlying architecture would still have the performance limitation.
- Rewriting OMT is estimated to take about the same number of years as implementing an ADMS but does nothing to address the current shortcomings of the existing DMS or its inability to fulfill future needs of Distributed Energy Resources requirements to meet customer choice and Clean Energy Transformation Act requirements. These shortcomings would need to be addressed in a future project, extending the timing for when Avista would be able to meet those requirements and significantly increasing the total cost of ownership.

- **Alternative 3** – Continue to use OMT **-** There's an option to continue to use the existing OMT in its current format with continued minor enhancements to keep it operational. It would not resolve any of the issues that have been identified throughout this narrative. In addition, delaying the start of a project to replace OMT and the DMS with a modern ADMS increases the risk that the existing systems will fail before an ADMS project can be completed. Avista needs to proceed with the work now in order to be ready for the future, in a similar way to how planning is done for future power needs; i.e., we don't wait until we run out of power to build new generation.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Avista tracks a large number of electric system reliability statistics (SAIDI, SAIFI, CAIDI, etc.) that can and will be used to benchmark and measure success of the project. The project team will work with key stakeholders to determine which reliability statistics would be directly or indirectly influenced by the increased capabilities and functionality of an ADMS and use those as one measure of the success for the project.

As mentioned in Section 1.2 there are a series of high customer value items enabled by the data provided to OMT/DMS from the AMI meters. Those metrics will be monitored to ensure the values are maintained and where possible improved with the integrated ADMS capabilities, such as automatic “ping” of AMI meters to validate power has been restored.

Wildfire Resiliency is a key focus area for Avista. The ADMS project team will coordinate closely with the Wildfire Resiliency team to determine key metrics they are tracking to ensure the planned fully digital damage assessment and restoration workflow accurately captures the necessary data.

Program details for the Clean Energy Implementation Plan (CEIP) and metrics are still being developed, however, it’s clear that the plan will include the need for additional grid automation, new Distributed Energy Resources, and new non-wires alternatives for customers such as time of use rates and energy efficiency. Many of these potential alternatives of being explored in the Connected Communities project which is planned to start in 2023 and run for five years. Results of the project will be used to determine which alternatives will move out to the larger customer base. The ADMS project Team will be coordinating with the Connected Communities team as both projects are underway.

In order to achieve these goals a future utility architecture that bridges use cases across Customer, Grid, Operations, and Utility Enterprise domains is required. This future will require a technology platform that enables the integration of these domains. The industry standard for this platform is an Advanced Distribution Management System (ADMS). As details of the CEIP and others become more well defined in the coming years, the ADMS team will work collaboratively with these teams to determine specific metrics that will be achieved via the capabilities of the ADMS.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The ADMS project is scheduled to start in mid-2023 and estimated to have a four-year duration. Upon completion, the ADMS will fully replace both the existing Outage Management Tool and the Distribution Management System and provide additional Distributed Energy Resource Management (DERM) functionality in support of the CEIP and Connected Communities project. The investment is planned to be deployed in two phases. First phase is planned to be used and useful in 2025 and the second phase in late 2026. The project costs related to each phase would transfer to plant in those years.

Phase 0

Test ADMS in Avista's Lab

- Test ability of the selected system with real-world use cases and devices
- Confirm design approach and inform the detailed design work
- Results used to refine scope schedule and budget for the main project

CIM Compliant model

- Prepare the CIM-compliant model to be available at the starting point of the ADMS project
- *Network model for a specified substation/feeders will be transferred via GIS CIM exporter (built by Avista)*

Phase 1

Phase 1A

Go-live with the OMS only

- Legacy DMS still used for operations and New DMS only for monitoring
  - Requires a parallel path for DNP3 communication with RTUs
- ICCP integration between legacy DMS and New DMS for parallel operation
- Configure all RTUs to provide a parallel data stream to the ADMS Front End
- Implement all ADMS integrations
- Establish CIM (GIS) and understand how to deliver data to ADMS
- Decommission legacy OMT

Phase 1B

Go-live with New DMS

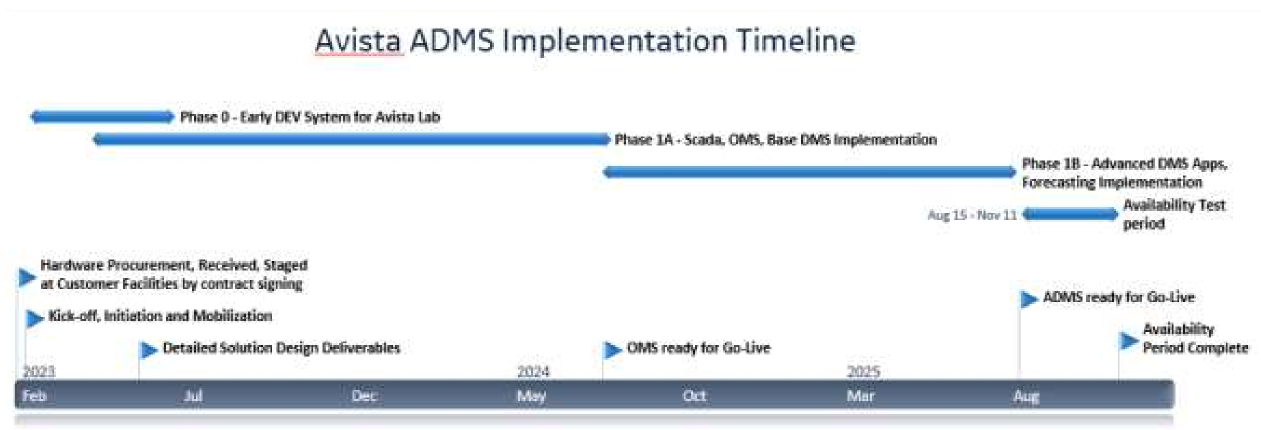
- New DMS to Go-live after period of stability of OMS
- Switch over RTUs to New DMS
- Decommission legacy DMS

Phase 2

OpenDSO Enhancements

- Incorporate learning from Connected Communities and other initiatives at the lab
- Begin with Connected Communities Feeders
- Strategically/expanded to other DMS enabled feeders
- Implement DERMS functionality

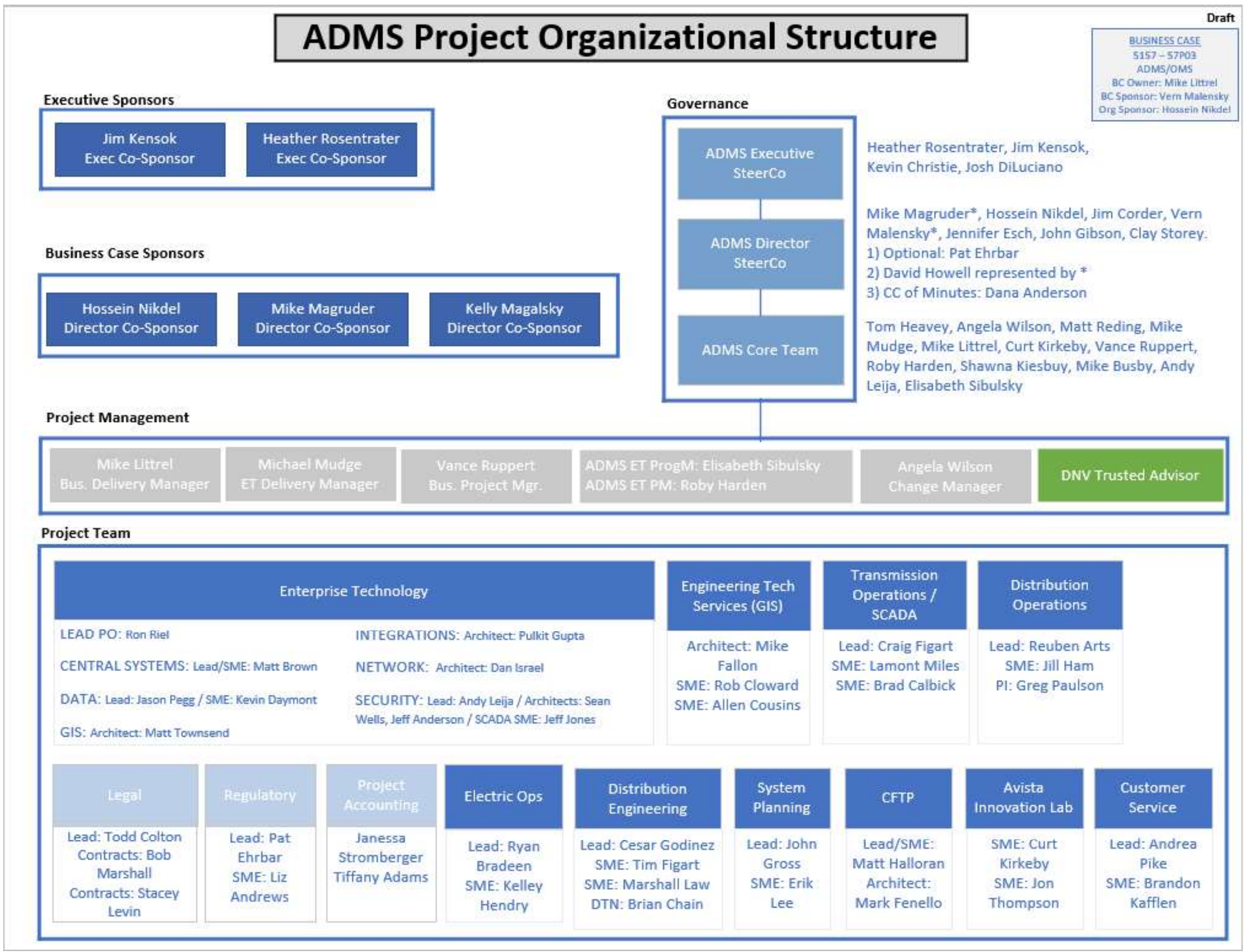
Preliminary Project timeline from the RFP Response



2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

This business case will have two levels of governance: The Executive Technology Steering Committee (ETSC), and Project Steering Committee that will be formed as part of the project initiation. The committees will review monthly project status reports, which identify project scope, schedule, and budget, as well as any risks and/or issues that the project team has identified.

Status reports to the steering committees will be used as the official review and approval process for prioritization and change requests. Risks, issues and change requests will be documented in project logs and kept as artifacts of each project within Enterprise Technology's project management software system.



3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the **Outage Management System and Advanced Distribution Management System** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Mike Littrel 9DDE7FC206184AF...	Date:	May-10-2023 | 1:33 PM PDT
Print Name:	Mike Littrel		
Title:	Manager of Energy Delivery Technology Projects		
Role:	Business Case Owner		
Signature:	DocuSigned by: Mike Magruder 13E5B221EFEE401...	Date:	May-10-2023 | 4:19 PM PDT
Print Name:	Mike Magruder		
Title:	Director of Transm. Ops & System Planning		
Role:	Business Case Sponsor		
Signature:	DocuSigned by: Hossein Nikdel E4E2D9C7EE4747F...	Date:	May-10-2023 | 1:57 PM PDT
Print Name:	Hossein Nikdel		
Title:	Director of Applications and Systems Planning		
Role:	Business Case Sponsor		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Protection System Upgrade for PRC-002

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The purpose of this business case was to complete the work needed to be compliant with the new FERC PRC-002 standard at several substation locations. This standard is titled 'Disturbance Monitoring and Reporting Requirements' and requires sequence of events recording (SER) and fault recording (FR) data. During the scoping process for these projects, several additional equipment replacements were identified. All substation locations are now compliant with FERC Standard PRC-002 and the imminent failures were addressed under this business case while crews were on site to avoid extra site visits and mobilization costs. Other work that had been identified during the PRC-002 scoping process will be completed under the Substation – Substation Rebuild (renamed Substation – Asset Condition) business case, this change resulted in smaller Transfer to Plant costs than scheduled.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This Business Case was monitored through the year and reviewed at the Electrical Engineering Budget Committee each month. The PRC-002 compliance project is complete.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

The offsets will not change due to the scope change.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

DocuSigned by:
X Brian Chain
C4012FF13CFC491...

DIRECTOR SIGNATURE:

DocuSigned by:
X Vern Malensky
06C4FF5AB09E40B...

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Regulating Hydro

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

Avista's regulating hydro plants are unique in that they have storage available in their reservoirs. This enables these plants to have operational flexibility and are operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and other types of services necessary to provide a stable electric grid and to maximize value to Avista and its customers. These plants are the four largest hydro plants on Avista's system representing more than 950 MW of power and include Noxon Rapids and Cabinet Gorge on the Clark Fork River in Montana and Idaho and Long Lake and Little Falls on the Spokane River. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation.

During a Part 12 inspection it was discovered that the airshafts at Noxon Rapids HED had vertical cracks that extend through the body of the dam that were daylighting on the downstream face. Water leaking through the cracks created large volumes of ice during the winter months. The ice creates a safety hazard to personnel and equipment on the powerhouse roof due to ice fall hazard. The ice fall hazard also presents an environmental risk due to possibility of rupturing transformers and releasing oil. Previous attempts at intervention have reduced the risk, but have not eliminated it. Unit 1 had the same issue and a contractor was brought in during the scheduled annual Spring outage to install a waterproof geomembrane liner within the air shaft. The repair was completed on Unit 1 and has eliminated the downstream face leakage. The membrane has been purchased for $24,000 and is on site. The repair was done by the same contractor that has knowledge of the facility and work process. The estimates were based on past work on Unit 1.
Risk of damaged equipment and extended outages were eliminated as a result of the projects. Unit 2 was in the worst condition of all the units and had significantly more leakage and thus more ice buildup each winter. In addition to reducing or eliminating ice buildup the air shaft liner will help in mitigation of leakage around scroll cases in the dam. This mitigation measure was presented to FERC during Part 12 inspection as a means of intervention. Materials and labor costs were well known and the work could be completed within 2023.

The work was dependent upon a 3-4 week unit outage for Unit No. 2, as such, the work was scheduled to coincide with the unit outage in September/October. The main reason to accelerate the work into 2023 was to coincide with the annual maintenance in Fall to prevent an additional off cycle, costly outage, meet FERC's requirement to mediate and prevent more damage during the winter. As a result of this work, an additional unplanned variance of $691,796 was transferred to plant in 2023.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

An in-year funds request was submitted in September of 2023 and the Capital Planning Group approved an increase in total budgeted spend to $3,650,000. Capital spend for this program is reviewed and adjusted monthly. After reviewing the budget and actual spend results, with consideration of completed and upcoming work, GPSS leadership agrees on submitting funds requests or releases, as necessary. Funds Requests are submitted to the company's Capital Planning Group (CPG) for consideration. Approved funds request related to this work is included with this form.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets for this period.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Gregory Wiggins
Gregory Wiggins (Feb 29, 2024 11:49 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 29, 2024 12:29 PST)

_ER 4148 - Capital Additions Variance Explanation Form 202402

Final Audit Report 2024-02-29

Created:	2024-02-29
By:	Rhiannon Hurst (rhiannon.hurst@avistacorp.com)
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"_ER 4148 - Capital Additions Variance Explanation Form 202402" History

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1.0 CHANGE REQUEST #1-2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
09/01/2023	*Timing Change, Internally Driven*	1	$3,150,000	$500,000		$3,650,000
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
9/01/2023	Timing Change, Internally Driven	-	-	2023	2023
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This should not be considered approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024			-	-	-	-
2025			-	-	-	-
2026			-	-	-	-
2027			-	-	-	-
2028			-	-	-	-

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The air shafts at Noxon Rapids dam have vertical cracks extending through the body of the dam and are daylighting on the downstream face. Water is leaking through the cracks creating large volumes of ice during the winter months. The ice creates a safety hazard to personnel and equipment on the powerhouse roof due to ice fall hazard. The ice fall hazard also presents an environmental risk due to possibility of rupturing transformers and releasing oil. Previous attempts at intervention have reduced the risk, but have not eliminated it. Unit 1 had the same issue and a contractor was brought in during the scheduled annual Spring outage to install a waterproof geomembrane liner within the air shaft. The repair was completed on Unit 1 and has eliminated the downstream face leakage. The membrane has been purchased for $24,000 and is on site. This repair will be done by the same contractor that has knowledge of the facility and work process. The estimates are based on past work on Unit 1.

Risk of damaged equipment and extended outages are eliminated as a result of this project. Unit 2 is in the worst condition of all the units and has significantly more leakage and thus more ice build up each winter. In addition to reducing or eliminating ice buildup the air shaft liner will help in mitigation of leakage around scroll cases in the dam. This mitigation measure was presented to FERC during Part 12 inspection as a means of intervention. Materials and labor costs are well known and this work can be completed this year.

Project is dependent upon a 3-4 week unit outage for Unit No. 2. This work is currently scheduled to coincide with the unit outage in September/October. The main reason to accelerate this work into this year is to coincide with the annual maintenance this Fall to prevent an additional off cycle, costly outage in the future.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature
Greg Wiggins	BC Owner	
Alexis Alexander	BC Sponsor	
	Steering Committee (If applicable)	

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Saddle Mountain 230/115kV Station (New) Integration Project Phase 2

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Saddle Mountain Integration project is a two-phase project that includes building two substations and the interconnections and upgrades to improve reliability and capacity in the Othello area. Phase Two of the project includes the Othello 115kV Substation rebuild. The original schedule was set to have the new Othello 115kV substation completed in the fourth quarter of 2022 but due to schedule changes to accommodate the 2022 agricultural water season in the region, the distribution cutover work for the new Othello substation was delayed. This pushed the commissioning and testing work to finalize the new substation to the first quarter of 2023. The substation was put into service in February 2023 and several network and communication projects were complete in the Fall of 2023. Final removal and cleanup at the old Othello substation site will be complete in early 2024. This caused the Transfer to Plant in 2023 to be much higher than planned.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This Business Case was monitored through the year and reviewed at the Electrical Engineering Budget Committee each month. As cost adjustments were identified, a decision was made to reduce funds through the Capital Planning Group. Attached is the formal request for budget reduction.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets due to this project.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

DocuSigned by:
X Brian Chain
C4012FF13CFC491...

DIRECTOR SIGNATURE:

DocuSigned by:
X Vern Malensky
06C4FF5AB09E40B...

Saddle Mountain Integration Project Phase 2

1.0 CHANGE REQUEST #02 – 12/2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
12/2023	*Revised Cost*	02	$1,870,000	-$250,000		
09/2023	Timing Change, Internally Driven	01	$1,950,000	-$80,000	-$80,000	$1,870,000

Complete the following for the current request

CURRENT YEAR REQUESTS

Request Date	Offsets Impact			TTP Impact	
	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
09/2023	Timing Change, Internally Driven	$0	$0		
12/2023	Revised Cost	$0	$0		

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

Year	Funding Impact		Offsets Impact		TTP Impact	
	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED.[6]

09/2023: The remote end work at South Othello substation that supports the new Othello substation is on going due to design and procurement delays. The new Othello substation is complete. The old Othello substation is being dismantled and removed. The demotion work has come in under budget and some work has been delayed into 2024.

12/2023: Several projects completed under the Expected Spend. Price adjustments for demolition work are better reflected in this adjustment.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Brian Chain	BC Owner	DocuSigned by: Brian Chain	Dec-15-2023 | 6:33 AM PST
Vern Malensky	BC Sponsor	DocuSigned by: Vern Malensky 06C4FF5AB09E40B...	Dec-15-2023 | 7:10 AM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

SCADA – SOO and BuCC

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

SCADA typically budgets around $700k per year for typical average capital expenditures and transfers to plant. In late 2023, however, our SCADA vendor required Avista to move from a perpetual EMS licensing agreement (O&M costs) to a five-year term license agreement that could be capitalized at an 80/20 split. Included in this term license agreement was accommodation for a new Dynamic Line Ratings (DLR) application that Avista needs to meet FERC Order 881 requirements. Therefore, an additional $1.84M in capital costs were incurred in 2023 than were typically expected and originally planned for.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The CPG funds change request is attached detailing the requested allocation increases.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

Per Section 1.1.4 in attached CPG funds change request, annually escalating costs of $358k in perpetual licensing renewals will be reduced to $92k annually for EMS and DLR licensing. In summary, assuming a 12.75% escalation of former annual perpetual licensing renewals, moving to 5yr term licensing provides a break-even over five years.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Craig N. Figart

DIRECTOR SIGNATURE:

X Michael A Magruder

SCADA – SOO and BuCC

1.0 CHANGE REQUEST #1 – 11.14.2023

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
11.14.2023	*Revised Cost*	1	$2,305,000	+$262,000		$2,567,000

Complete the following for the current request

CURRENT YEAR REQUESTS

Request Date	Offsets Impact			TTP Impact	
	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
11.14.2023	Revised Cost	$0	$0	n/c	**n/c**

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

Year	Funding Impact		Offsets Impact		TTP Impact	
	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	n/c	n/c	n/c	n/c	n/c	n/c
2025	n/c	n/c	n/c	n/c	n/c	n/c
2026	n/c	n/c	n/c	n/c	n/c	n/c
2027	n/c	n/c	n/c	n/c	n/c	n/c
2028	n/c	n/c	n/c	n/c	n/c	n/c
5yr TOTAL			n/c	n/c		

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

SCADA – SOO and BuCC

1.1 THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED.[6]

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

$60k – SCADA refresh

In order to accommodate ADMS project requirements, SCADA accelerated the replacement of Distribution Operations (DO) client pcs and monitors. This is 30% above the typical $200k annual allocation estimate under the SCADA Hardware Refresh revolving capital project.

$70k – Operator Training Simulator

The Operator Training Simulator project has incurred an additional $70k (29%) in costs over the original $240k CPR during implementation than originally anticipated.

$45k – Network Refresh

The 3750 Switch Refresh project has incurred additional an additional $45k (31%) in costs over the original $145k CPR during implementation than originally anticipated.

$40k Internal Firewall Refresh

The SCADA Internal Firewall Refresh project has incurred an additional $40k (20%) in costs over the original $200k CPR during implementation than originally anticipated.

$12k CIP-012 Protections

The CIP-012 Protections project has incurred an additional $12k (8%) in 2023 costs over the original $142k CPR during implementation than originally anticipated.

$20k RTU IO Replacements

The RTU IO Replacement project has incurred an additional $20k (11%) in 2023 costs over the original $174k CPR planned scope during implementation than originally anticipated. This is primarily due to the addition of a development RTU to be used for project and on-going future testing and validations.

$15k SOO NetApp Refresh

The SOO NetApp Refresh project has incurred an additional $15k (14%) in 2023 costs over the original $110k CPR during implementation than originally anticipated. An invoice from professional services came in late after the project was closed. The project was reopened in 2023 to capture this cost.

Total net Business Case Funds Change Request of $262k.

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

SCADA refresh

Refresh of the DO client pcs is needed now in order to upgrade the out-of-support hardware to meet NERC CIP compliance as we move them into our CIP Electronic Security Perimeter as part of the ADMS project, thereby simplifying and enhance the DO user access and interaction experience.

All hardware has been purchased and associated costs incurred against the project. The remaining labor to install and commission the pcs can be deferred to 2024, but would be an extremely negligible amount, on the order of under $10k.

Operator Training Simulator

The Operator Training Simulator project is already soft-closed and thereby no ability to avoid this additional project cost.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

SCADA – SOO and BuCC

<u>Network Refresh</u>

The 3750 Switch Refresh project is all but complete with just a few remaining labor hours to complete the replacement of the last two switches. The risk involved by delaying this remaining 20 hour effort would incur three months of additional AFUDC charges and less than $3k in cost shift to 2024.

<u>Internal Firewall Refresh</u>

The SCADA Internal Firewall project has already been closed and costs have already been incurred.

<u>CIP-012 Protections</u>

The CIP-012 Protections project project has already been closed last spring.

<u>RTU IO Replacements</u>

The RTU IO Replacement project spans both 2023 and 2024. There were plans to spend 20-40 hours of labor at the BuCC during the remainder of 2023, thus there would be the movement of $3-6k from 2023 to 2024.

<u>$15k SOO NetApp Refresh</u>

The SOO NetApp Refresh project has incurred and has already been closed.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

n/a

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

n/a

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

n/a

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The stable and secure operation of Avista's new SCADA/EMS systems will benefit our customers by safe, secure, and reliable operation of Avista's transmission, distribution, and gas systems.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

Confirmed.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Craig N Figart	BC Owner	Craig N. Figart	Nov 14, 2023
Michael Magruder	BC Sponsor	Michael A Magruder	Nov 14, 2023
	Steering Committee (If applicable)		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Clean Energy Fund 3 – Eco District G2G

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Eco District G2G project is a demonstration project partially funded from the State of Washington's Cleaner Energy Fund Grid Modernization program. The project demonstrates how buildings and energy storage can be coordinated with each other for benefits to the grid and customers. The project serves as a non-wires alternative to substation construction based on load growth forecasts, in addition to providing valuable customer benefits and exemplifying methods to make a clean energy future more affordable.

The previous plan was to install the project assets in 2022, but the project experienced delays causing the assets to be commissioned and transferred in 2023. The attached business case funds change request describes the issues causing the delays in detail. There were several innovative approaches used on this project, including a DC-bus system and a predictive optimizer, both of which ran into unforeseen issues.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

The variance is mostly due to plant transfer being delayed from 2022 to 2023. The delay did cause additional project costs, for which Avista's funding change request process for strategic projects was followed. The funding changes were approved by the Invent Council, which is the governing team who allocates funding and approves strategic projects.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no revised offsets associated with this change in plant additions. The Clean Energy Fund 3 project was partially funded by the Department of Commerce and is part of a series of Washington State supported efforts to advance the clean energy economy in the state. The project has demonstrated how energy storage (thermal and electric) can be utilized for customer demand management and provide a non-wires alternative to traditional utility upgrades. The effort included $2.5M in grant funding from Commerce.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE: DIRECTOR SIGNATURE:

2/12/2024

X

Signed by: John

2/12/2024

X

John Gibson

Signed by: John

Clean Energy Fund 3 – Eco District G2G

CHANGE REQUEST #2 – JUNE 15, 2023

Previous Requests	Requested	Approved
5-Year Plan	$4,500,000	$4,500,000
C.R. #1	$300,000	$300,000

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	LTD Spend	Current Approval	Requested Change	Proposed Life Total
06-2023	$4,605,306*	$4,800,000	$700,000	$5,500,000

*Total life-to-date spend is the net utility contribution, after subtracting grant funding received from the Department of Commerce for the work already completed on the project. Similarly, the proposed life total of the project represents the utility contribution after subtracting the total grant funding.

Type of Change	In-year Update
Primary Reason for Change	Timing Change, Externally Driven
Response needed by	7/15/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

The project has experienced cost impacts related to two separate major tasks. The first is related the DC electric infrastructure, which caused significant delays. The second cost impact is related to the control system design.

The DC electric infrastructure issue was discovered during the factory acceptance test of the battery energy storage system in 2022. The Eco District project is utilizing a common DC bus and single power conversion system to connect solar and storage to the grid. During testing, the DC bus voltage was not stable due to a vendor issue (DC/DC converter). The result of this was a requirement to re-design the DC bus around different conversion equipment, which impacted the project schedule by approximately 6 months. Costs directly related to this delay include:

1) Design and construction fees (change orders) associated with modified DC bus: $144,384
2) Procurement of new DC bus equipment: $69,651 (including tax)
3) Avista Labor: $35,000
4) Additional AFUDC for months delayed by DC bus: $72,045

The control system design cost impacts are a result of several changes to the design. The project requires an optimizer/controller which can predict the building behavior and stage assets appropriately to achieve outcomes which are beneficial for the grid and customer. The initial vision of the optimizer has evolved as the project team learned more about the innovative new technologies being installed. Some approaches were found to be infeasible, and the design team pivoted toward solutions which could be implemented in the field. Avista's consultant responsible for the design did not exceed their budget, but the timeline of their work was extended, and internal Avista resources were required to take a much more active role than expected in order to ensure successful controller development and deployment. Costs directly related to the controller design changes include:

1) Avista Labor (Engineering and Project Management): $200,665

In the process of implementing new project controls (internal project management), the team identified the following items which also contribute to the funding change request:

1) Sales Tax associated with electrical construction and battery installation was not accounted for in the original estimate. This adds an incremental $116,710 to the budget beyond the original construction contract.
2) Avista Distribution Operations required a Harmonic study in addition to the internal interconnection system impact study, causing an additional $16,000 in consulting engineering fees.
3) The project team feels, given the unpredictable nature of the project, that the inclusion of a 7%, $45,545 contingency will reduce the risk of additional requests.

Summary of cost impacts:

DC design/construction change orders	$144,384
DC equipment	$69,651
Avista Labor	$235,665
Additonal AFUDC	$72,045
Construction Tax	$116,710
Harmonic Study for Avista DX Ops	$16,000
Contingency	$45,545
Total Change Request	**$700,000**

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

The work is necessary to fulfill the obligations of Avista's contract with the Washington State Department of Commerce. Without commissioning the battery (which requires the DC bus changes) or completing the optimization controller, the project would not receive the remainder of expected milestone payments of $1.3M. Deferring the request would increase AFUDC because the battery energy storage asset cannot be placed into service until work is complete. In addition to direct financial risks, failing to complete the project could cause reputational damage and cause important grid benefits to go unrealized.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Internal Avista labor, AFUDC, and sales tax on equipment and construction were forecasted using excel. **"Amend_1_[Term_Extension_to_10-30-2023]docx_W"** reflects the McKinstry change order amount, and "**Avista__ELM_CEF3_DC_Bus_Document_-_Rev_1doc"**" reflects ELM's DC Bus pricing.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

To achieve battery energization, the remainder of the work relies on the vendors and suppliers contracted with Avista, so there are no internal impacts other than the costs outlined above. Internal Avista engineering labor is required to demonstrate and operate the controller/optimizer. The engineering labor is in the Innovation Lab, meaning there will be a larger percentage of Lab resources assigned to CEF3 in 2023 than initially expected. The result of this will likely be a small decrease in O&M labor costs in the lab, due to the staff time needed to complete the capital work.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

When confronted with the DC equipment issue, the project team considered alternative designs such as reverting to a more traditional AC-interconnected system. That approach would have caused similar re-design and equipment procurement costs, so the team decided to continue with the DC approach because it provides efficiency benefits and aligns with our obligations under the Commerce contract. The controller design modifications are a result of analyzing alternatives and selecting the least cost option to achieve the requirements of the project.

Given the unexpected costs incurred, one alternative to consider is whether or not the project continues. The project team feels strongly that abandoning the effort would not be in Avista's or customers' best interest. First, we would not be able to receive the remaining milestone payments from Commerce, which total $1.3M and serve to offset the costs associated with innovative new technologies. Second, we would miss out on the opportunity to demonstrate impactful and strategic ways to integrate customer assets with the grid, paving the pathway for future business models, customer participation in non-wires alternatives, and benefits from from increased infrastructure utilization.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The investment in the CEF3 project is still prudent even with the additional costs. The optimized use of the assets installed during the project will deliver value to customers in the form of feeder capacity and increased infrastructure utilization, and provide a model for equitable customer participation in non-wires alternatives on the grid. These concepts are critical to ensuring our energy system of the future remains safe, reliable and affordable while transitioning toward a more distributed and clean resource mix.

Clean Energy Fund 3 – Eco District G2G

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The original justification narrative is still valid given this change. The increases in cost are the result of taking innovative approaches to creating the future grid. Avista's customers will still benefit from the assets and the original intent will be realized with the help of the additional funding.

CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
John Gibson	BC Owner		
Jason Thackston	BC Sponsor	J T	6/30/22
Adam Munson	FP&A		

Clean Energy Fund 3 – Eco District G2G

CHANGE REQUEST #2 – JUNE 15, 2023

Previous Requests	Requested	Approved
5-Year Plan	$4,500,000	$4,500,000
C.R. #1	$300,000	$300,000

For new change requests, update the Change Request # and Date. Add a new line to the table to log previous change requests

Month - Year	LTD Spend	Current Approval	Requested Change	Proposed Life Total
06-2023	$4,605,306*	$4,800,000	$700,000	$5,500,000

*Total life-to-date spend is the net utility contribution, after subtracting grant funding received from the Department of Commerce for the work already completed on the project. Similarly, the proposed life total of the project represents the utility contribution after subtracting the total grant funding.

Type of Change	In-year Update
Primary Reason for Change	Timing Change, Externally Driven
Response needed by	7/15/2023

1.1 ALL ITEMS IN THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST, INCLUDING BUT NOT LIMITED TO:

1.1.1 Identify what has changed such that the current approved amount is not sufficient.

The project has experienced cost impacts related to two separate major tasks. The first is related the DC electric infrastructure, which caused significant delays. The second cost impact is related to the control system design.

The DC electric infrastructure issue was discovered during the factory acceptance test of the battery energy storage system in 2022. The Eco District project is utilizing a common DC bus and single power conversion system to connect solar and storage to the grid. During testing, the DC bus voltage was not stable due to a vendor issue (DC/DC converter). The result of this was a requirement to re-design the DC bus around different conversion equipment, which impacted the project schedule by approximately 6 months. Costs directly related to this delay include:

1) Design and construction fees (change orders) associated with modified DC bus: $144,384
2) Procurement of new DC bus equipment: $69,651 (including tax)
3) Avista Labor: $35,000
4) Additional AFUDC for months delayed by DC bus: $72,045

The control system design cost impacts are a result of several changes to the design. The project requires an optimizer/controller which can predict the building behavior and stage assets appropriately to achieve outcomes which are beneficial for the grid and customer. The initial vision of the optimizer has evolved as the project team learned more about the innovative new technologies being installed. Some approaches were found to be infeasible, and the design team pivoted toward solutions which could be implemented in the field. Avista's consultant responsible for the design did not exceed their budget, but the timeline of their work was extended, and internal Avista resources were required to take a much more active role than expected in order to ensure successful controller development and deployment. Costs directly related to the controller design changes include:

1) Avista Labor (Engineering and Project Management): $200,665

In the process of implementing new project controls (internal project management), the team identified the following items which also contribute to the funding change request:

1) Sales Tax associated with electrical construction and battery installation was not accounted for in the original estimate. This adds an incremental $116,710 to the budget beyond the original construction contract.
2) Avista Distribution Operations required a Harmonic study in addition to the internal interconnection system impact study, causing an additional $16,000 in consulting engineering fees.
3) The project team feels, given the unpredictable nature of the project, that the inclusion of a 7%, $45,545 contingency will reduce the risk of additional requests.

Summary of cost impacts:

DC design/construction change orders	$144,384
DC equipment	$69,651
Avista Labor	$235,665
Additonal AFUDC	$72,045
Construction Tax	$116,710
Harmonic Study for Avista DX Ops	$16,000
Contingency	$45,545
Total Change Request	**$700,000**

1.1.2 Identify why this work is needed now and what risks may result if this request is not approved or if it is deferred.

The work is necessary to fulfill the obligations of Avista's contract with the Washington State Department of Commerce. Without commissioning the battery (which requires the DC bus changes) or completing the optimization controller, the project would not receive the remainder of expected milestone payments of $1.3M. Deferring the request would increase AFUDC because the battery energy storage asset cannot be placed into service until work is complete. In addition to direct financial risks, failing to complete the project could cause reputational damage and cause important grid benefits to go unrealized.

1.1.3 Please reference analysis or information that support the problem and attach to this document.

Internal Avista labor, AFUDC, and sales tax on equipment and construction were forecasted using excel. **"Amend_1_[Term_Extension_to_10-30-2023]docx_W"** reflects the McKinstry change order amount, and "**Avista__ELM_CEF3_DC_Bus_Document_-_Rev_1doc"**" reflects ELM's DC Bus pricing.

1.1.4 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented; including additional O&M costs, employee or staffing, reductions to O&M (offsets), etc.

To achieve battery energization, the remainder of the work relies on the vendors and suppliers contracted with Avista, so there are no internal impacts other than the costs outlined above. Internal Avista engineering labor is required to demonstrate and operate the controller/optimizer. The engineering labor is in the Innovation Lab, meaning there will be a larger percentage of Lab resources assigned to CEF3 in 2023 than initially expected. The result of this will likely be a small decrease in O&M labor costs in the lab, due to the staff time needed to complete the capital work.

1.1.5 Discuss what alternatives were considered. Describe why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation).

When confronted with the DC equipment issue, the project team considered alternative designs such as reverting to a more traditional AC-interconnected system. That approach would have caused similar re-design and equipment procurement costs, so the team decided to continue with the DC approach because it provides efficiency benefits and aligns with our obligations under the Commerce contract. The controller design modifications are a result of analyzing alternatives and selecting the least cost option to achieve the requirements of the project.

Given the unexpected costs incurred, one alternative to consider is whether or not the project continues. The project team feels strongly that abandoning the effort would not be in Avista's or customers' best interest. First, we would not be able to receive the remaining milestone payments from Commerce, which total $1.3M and serve to offset the costs associated with innovative new technologies. Second, we would miss out on the opportunity to demonstrate impactful and strategic ways to integrate customer assets with the grid, paving the pathway for future business models, customer participation in non-wires alternatives, and benefits from from increased infrastructure utilization.

1.1.6 Discuss, if given this change, how this investment is still prudent for the company to continue for the benefit of our customers.

The investment in the CEF3 project is still prudent even with the additional costs. The optimized use of the assets installed during the project will deliver value to customers in the form of feeder capacity and increased infrastructure utilization, and provide a model for equitable customer participation in non-wires alternatives on the grid. These concepts are critical to ensuring our energy system of the future remains safe, reliable and affordable while transitioning toward a more distributed and clean resource mix.

1.1.7 Confirm that the justification narrative is still valid given the nature of this change. If not, indicate that the narrative will be updated to incorporate.

The original justification narrative is still valid given this change. The increases in cost are the result of taking innovative approaches to creating the future grid. Avista's customers will still benefit from the assets and the original intent will be realized with the help of the additional funding.

CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before funding can be considered.

Name	Role	Signature	Date
John Gibson	BC Owner		
Jason Thackston	BC Sponsor	JT	6/30/22
Adam Munson	FP&A		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Substation – Asset condition (formerly Substation – Substation Rebuilds)

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Substation – Substation Rebuilds (renamed Substation – Asset Condition) business case supports asset condition driven projects across our service territory. This includes the purchase of major equipment spares (i.e. power transformers and high voltage breakers), small equipment replacements (i.e. Voltage Regulators), and major substation rebuild projects. The original plan for 2023 was to complete substation rebuilds at Davenport 115kV, Sunset 115kV, Metro 115kV and complete a transformer replacement at Inland Empire Paper. The projects at Davenport and Sunset were completed plus several property purchases for future substation construction. The Inland Empire Paper transformer replacement project was pushed into future years (tentatively planned for 2025 or 2026) due to customer outage requirements and engineering resource limitations. The Metro 115kV rebuild project was moved to its own business case and is scheduled to be complete in 2027.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This Business Case was monitored through the year and reviewed at the Electrical Engineering Budget Committee each month. As budget reductions were identified, a decision was made to request funds be reduced through the Capital Planning Group. Attached is the formal request for funding adjustments.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no changes to the offsets for this business case.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

DocuSigned by:
X Brian Chain
C4012FF13CFC491...

DIRECTOR SIGNATURE:

DocuSigned by:
X Vern Malensky
06C4FF5AB09E40B...

Substation Asset Condition

EXECUTIVE SUMMARY

Please provide a one page summary of the business case and high-level summary of the projects or programs included. Please describe the need for the project (a synopsis of the problem, the current state, and recommended solution), alternatives considered, the cost of the recommended solution, applicable metrics, customer benefits, Avista benefits or offsets derived from the investment, and risks, to customer and Avista, if the business case is not funded.

The Substation Asset Condition Business Case was formerly the Substation Rebuilds Business Case. The name is being changed to better align the set of projects with the Project Driver. Substation Asset Condition is one of the largest business cases for Avista because there is a vast amount of expensive equipment necessary to serve customers reliably through our electric system

Substations are necessary for serving customers properly. Substations transform electrical energy from high voltage transmission lines to lower voltage distribution lines that feed customers service points. Substations also allow switching, which contributes to reliability and the ability to maintain the system. Substations can be meter points as well as locations that provide protection for the expensive assets that can be vulnerable to faults. Substations are one of the main locations where voltage can be controlled.

The Substation Asset Condition Business Case is comprised of three ERs. ER 2000 includes major equipment spares (power transformers, high voltage breakers etc) that are held in stock until they are transferred to a location. ER 2204 includes major substation projects that contain multiple equipment asset condition issues, compliance updates and capacity upgrades. A substation rebuild is planned when several equipment types are at end of life. These projects also include significant Distribution system, Transmission system and Communication system work. ER 2215 includes small substation projects (single transformer replacements, regulator upgrades, etc) that have been deemed needed due to asset condition leading to imminent equipment failure. Equipment failures for capital items that have been run to failure are funded through ER 2215

Substation equipment needs to be replaced when it fails to fulfill its intended function. Substation equipment may also need to be replaced when it has become obsolete. Obsolescence is due to parts or software not being available to maintain a piece of equipment. There were 95 projects opened and completed in 2020 that aimed at addressing individual pieces of equipment that failed to fulfill their intended purpose or became obsolete.

Good, reliableelectric service to customers is dependant on the Substation Asset Condition Business Case being able to address issues, when necessary, at Avista's 165 substations. If not funded, customers would have poor electric service, numerous outages and be dissatisfied.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Madden/Kusel*	*Initial draft of original business case*	*5/12/2023*
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	

Substation Asset Condition

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$37,500,000	$15,000,000
2025	$38,500,000	$25,000,000
2026	$39,000,000	$35,000,000
2027	$29,500,000	$18,000,000
2028	$24,500,000	$30,000,000

Project Life Span	Ongoing
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Vern Malensky
Sponsor Organization/Department	Electrical Engineering
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.

1.1. What is the current or potential problem that is being addressed?

Avista substations have numerous age related issues that lead to repeated failures and need to be addressed on a regular basis. At a point where an overwhelming number of issues in a substation yard exist, rebuilding the entire substation is necessary.

The Substation Asset Condition Business Case includes three types of projects: Capital Spares, Asset Management Capital Maintenance and Substation Rebuilds.

ER 2000 includes major equipment spares (power transformers and high voltage breakers) that are held in stock until they are transferred to a substation location. This ER and associated project numbers are separated from the other two ERs in this business case because they don't have specific substation projects that they are associated with at the time of purchase of the assets.

ER 2215 includes small substation projects (single transformer replacements, regulator upgrades, high-voltage circuit breakers, lower voltage circuit breakers and reclosers, circuit switchers, capacitor banks, etc.) that have been deemed needed due to asset condition leading to imminent equipment failure. This ER is for individual equipment replacements and is separated from the other two ERs in this business case because it is focused on specific stations but is not a total rebuild of a substation.

ER 2204 includes major substation projects, i.e. a rebuild, that include multiple equipment asset condition issues, compliance updates or capacity upgrades. A substation rebuild is planned when several equipment types are at end of life or have other reasons triggering the need for replacement. These projects also include significant Distribution system, Transmission system and Communication system work.

It is preferred to perform substation rebuilds on a non-energized substation parcel (or portion of the current property) which is called a 'greenfield' rebuild. This allows for quicker construction and safer conditions for the crews building the new station. A substation can also be built on the current site, a 'brownfield' rebuild. Brownfield rebuilds are much more complicated due to construction occurring within an energized substation. See Section 2.1 for a table indicating the plan for which substations are planned to be greenfield and which are planned to be brownfield.

Replacing substation apparatus and equipment as it fails, approaches end of life or becomes obsolete is necessary to maintain safe and reliable operation of Avista's transmission and distribution systems. Avista's purpose is to improve life's quality with energy, safely, reliably and affordably. Functioning substations are key to fulfilling this purpose.

Substation equipment that no longer fulfills its intended purpose has failed. Often, the failure is a complete inability to function. However, a piece of equipment that no longer provides the function of its intended purpose has failed and should be replaced.

While asset condition is the primary driver triggering the need to replace major apparatus and equipment, additional factors that may contribute to the need to broaden the scope of a station rebuild project include operational and maintenance requirements, updated design and construction standards, SCADA communications, future customer load-service needs, and other programs (e.g. Grid Modernization).

Because much of the equipment in a substation was installed at the same time, it often reaches the end of life at a similar period in time. Therefore, Asset Management evaluations of a substation can be performed to determine if just a few pieces of equipment need to be replaced or if it is cost-effective to rebuild the entire substation.

Rebuilding significant portions of substations or the entire substation may be triggered after an equipment failure due to some of the other equipment in the substation being obsolete. Obsolete equipment is equipment that there are no or limited replacement parts or software is not supported.

Another reason a substation rebuild project may expand in scope after a piece of equipment fails is that updated equipment spacing requirements may need to be accommodated. Appropriate spacing of equipment in a substation is necessary because of the need to limit the situation of a fire traveling from one piece of equipment to another piece of equipment. Additionally, arc flash safety distances as well as proper physical access to equipment may be reasons why additional spacing between equipment is warranted and thus, among other factors a substation rebuild may be needed.

Substation major apparatus includes high-voltage circuit breakers, lower voltage circuit breakers and reclosers, circuit switchers, capacitor banks, power transformers and step voltage regulators. Associated equipment includes relays, meters, surge arrestors, station rock and fencing, panel houses, instrument transformers, high voltage fuses, air switches, autotransformer diagnostic equipment, batteries and chargers, and panel houses.

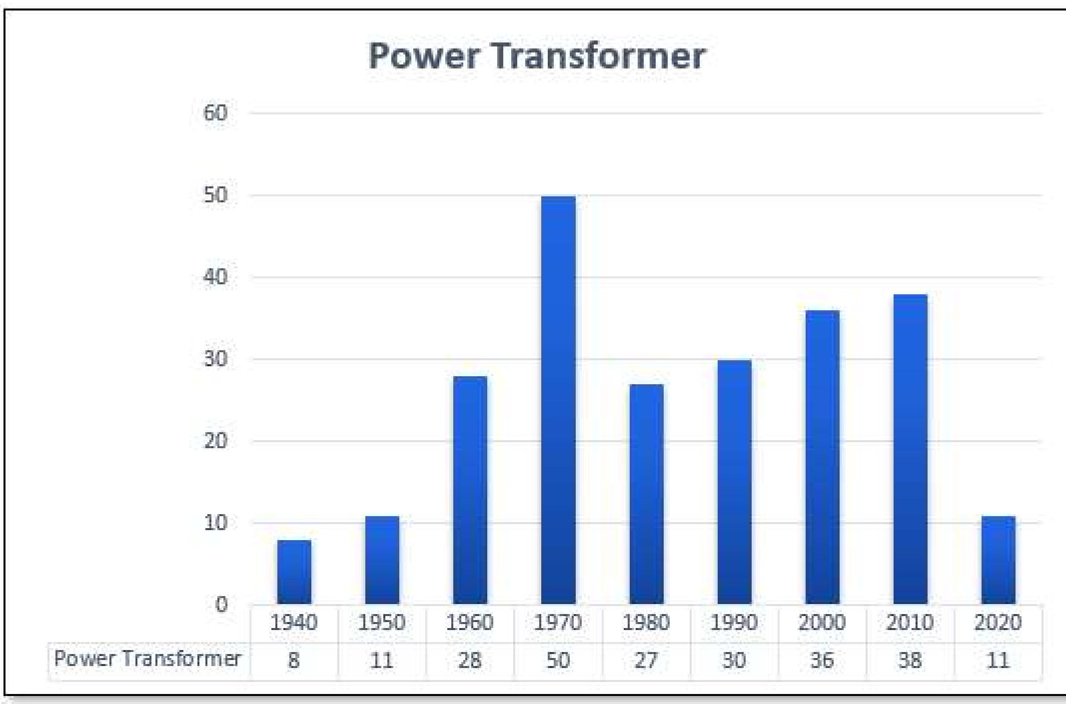
Substation Asset Condition

Equipment Type	System Count
Air Switch (>100kV)	1,063
Battery Banks	142
Circuit Breakers (<100kV)	495
Circuit Breakers (>100kV)	394
Circuit Switchers	121
Power Transformers	235
Voltage Regulators	1,085

Failure to replace failed and obsolete equipment will increase the risk of more frequent and/or extended duration of outages due to major equipment failure and inability to maintain major apparatus. Substation outages may have significant consequences as they tend to impact a large number of customers.

Aging apparatus and equipment plus changes in customer needs and compliance requirements contribute to the heavy need for substation rebuilds on the Avista system. Using up of extra capacity on the Avista distribution system has Avista's Electric Distribution Substations in a state of vulnerability. Substation failures can result in customer outages because of a lack of capacity for Operations Engineers to be able to switch around outages with the use of other capacity on the system

As with any electric supply system, there are many types of equipment at varying ages and conditions. See the table below for an example of an age profile. While operating and maintaining this equipment, sometimes issues arise and a replacement is necessary to avoid customer outages or maintain employee safety. Currently, Avista owns and maintains 165 substations.



1.2. Discuss the major drivers of the business case.

The work included in this business case is asset condition and failed plant based.

Asset Management Replacement projects include equipment replacements based on the following strategies:

Equipment Type	Asset Management Strategy
Air Switches (>115kV)	Inspection-based replacement
Battery Banks	Calendar-based replacement
Circuit Breakers (>115kV)	Monitor-based and Inspection-based replacement
Circuit Breakers (<115kV)	Inspection-based replacement
Circuit Switchers	Inspection-based replacement
Power Transformers	Monitor-based and Inspection-based replacement
Voltage Regulators	Run to Failure

Substation rebuilds are typically asset condition based but other drivers like 'Performance & Capacity' and 'Customer Service Quality and Reliability' can play a role in triggering a total substation rebuild.

Asset Condition situations can result in customer outages. Often momentary or short duration outages occur at the time of an equipment failure. However, automated switching or Operations Engineers switching around outages can bring most affected customers' power back on line. However, with less overall extra capacity on the system there is a stronger likelihood that that an equipment failure will cause sustained customer outages.

1.3. Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The Substation Asset Condition Business Case is a programmatic business case because of the need for continued rebuilding substations, replacing substation equipment and support of spare substation parts. With 165 substations, continued addressing of asset condition issues is necessary so that substation infrastructure continues to operate and service customers. If neglected, substations would not be able to support the electric system and outages to large numbers of customers would result. Substations typically serve between 1000 and 3000 customers.
Because Avista has 165 substations and substations can last at most, 80 years, Avista needs to rebuild about 2 substations per year to keep from having an overwhelming number of substations that need to be rebuilt.

Equipment expected life varies from equipment piece to equipment piece. Heavy electronic pieces of equipment may only last 10-15 years where mechanical equipment may last as long as 80 years. Continual replacement of equipment throughout the 165 substations helps to limit the number of stations that need to be totally rebuilt. Targeting levelized replacements or at least tracking them being aware of how close replacements are to levelized amount is an Asset Management strategy that helps keep reliability high and limits the potential of a bow wave of replacements that need to be done at the same time. See section 2.6 for amounts of replacements and levelized targets for some equipment.

Spare substation equipment is necessary to have on hand so that when a piece of equipment fails to operate or catches on fire and must be replaced, there are spares available. Typically a small number of the major equipment is necessary to have as spares because the equipment usually lasts quite long. Lately, lead times on equipment have doubled on most items, which necessitates having more spare pieces of equipment. Not having enough spare equipment in case of failure can lead to a substation failure and thus, customer outages and poor customer experience.

1.4. Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

The Substation Asset Condition Business Case keeps the system functioning which is "critical to serving our customers well and unlocking pathways to growth." The Perform Focus Area of Avista's focus goals is the primary alignment with the requested business case but there are elements to the business case which are aligned with the theme of our Vision, Mission, and Focus Areas.

Our Customers:
Existing and future customers in the Avista service area interested in having reliable electrical service. Avista needs to deliver a system which can maintain serving customers reliably.

Our People:
The portion of our company who will support the implementation of the project represents a core electric utility collection of our employees. These employees will benefit from this business case by having safe substations to work in.

Perform:
With continued work to address asset condition issues, our system will remain reliable and serve customers well

Invent:
Rebuilding substations with standard equipment is typical but Avista has the opportunity to improve the equipment, construction and delivery process as part of a large-scale program.

Vision; Better energy for life:
Investment in the substation system represents a long term invest of infrastructure which will be in place to serve our customers for several generations.

Mission; We improve our customers' lives through innovative energy solutions:
The Substation Asset Condition Business Case has been identified as the best method to maintain the reliability of Avista's substation system that are part of the backbone of an electrical system.

1.5. Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

All of Avista's substations except for one are located outside. Sun and weather take a toll on the equipment located outside. Over time, advances in technology make some substation equipment obsolete. The equipment may either not provide the function that is now expected of that equipment or replacement parts may not be available.

A couple examples of substations that were in need of rebuilding from mostly asset condition concerns are Sunset Substation (see picture below) and Davenport Substation.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Substation Asset Condition

The existing circuit breakers (one is the oldest in the Avista system) at the station do not have sufficient short circuit interrupting capability to interrupt close in faults on the connected transmission lines. It is also a compliance issue because it doesn't meet NERC performance requirements. System performance analysis indicates an inability of the System to meet the performance requirement R2.3 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer Scenarios for P0 events. No Operating Procedures are available to mitigate the system deficiencies.

The AC and DC service power and control circuit problems make adding or replacing equipment very difficult and expensive. Lack of capacity caused the mobile substation to need to be installed during 2021 Heat Event (see picture below).

The existing Davenport Substation dates to 1936 and is overdue for a rebuild given the existing site conditions (deteriorating panel house and fence, limited feeder flexibility and expansion capability to support future growth). Yard fencing, grading, grounding all present safety issues for employees and the general public. The substation yard has insufficient working safety clearances. The transformer and 115 kV disconnect switches are unsupported and have known issues. Bus regulation is non-standard. Feeder exit cables have hot spots and are an imminent failure risk. Various other condition issues (insulators, reclosers, etc) exist at this site as well. The Substation must be rebuilt off site due to limited space in the existing yard and limited property within close vicinity.

The Davenport Substation has 23 brown glass insulators. Brown glass insulators are an old technology used to insulate the structure from the energized wire. They have a history of breaking and falling on crews when the structure is shaken as they operate switches. Brown glass also has a history of not providing the insulation necessary to keep pole fires from occurring. Planned outages are needed to safely replace brown glass insulators proactively or under an emergency situation when an insulator breaks.

Substation Asset Condition

Kooskia Substation with split timbers and moss growing on the horizontal members.

2. PROPOSAL AND RECOMMENDED SOLUTION - Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).

2.1. Please summarize the proposed solution and how it helps to solve the business problem identified above.

The recommended approach is to replace substation apparatus and equipment as needed due to asset condition and rebuild substations when the majority of assets in the impacted substation have been determined to have reached their end of life. This business case aligns with the Company's mission to deliver safe and reliable electric service to customers by preventing the potential failure of substations that would lead to degradation of reliability and mitigating the frequency and duration of outages due to equipment failure.

The proposed solution is to increase the current funding level from where the programmatic Substation Rebuilds Business Case has been funded in the past. The spending for the ERs within the Substation Rebuilds Business Case are shown in the table below.

Substation Asset Condition

ER Description	2018	2019	2020	2021	2022	2023 (Expected Spend)
Substation - Capital Spares	$1,159,674	$751,580	$1,055,171	$0	$2,031	$1,400,000
Substation Asset Mgmt Capital Maintenance	$4,100,129	$3,756,452	$2,998,525	$2,822,820	$2,262,446	$5,610,000
Substation Rebuilds	$11,304,965	$6,653,240	$11,648,303	$14,089,960	$23,523,470	$32,184,569
Total	**$16,564,768**	**$11,161,271**	**$15,701,999**	**$16,912,780**	**$25,787,946**	**$39,194,569**

Increase costs due to inflation as well as aging substations and substation equipment has led to an increase in the budget for the Substation Rebuilds Business Case over the last five years. The inclusion of the large Metro project in the budget for 2022 and 2023 has contributed to the increase of spend.

As of the 2024 budget, the Metro Project will be its own business case, so the budget estimates for Metro are not show in the budget requests for 2024-2028. However, the request for the Substation Asset Condition Business Case funding continues to increase as shown in the table below.

ER Description	2024	2025	2026	2027	2028
Substation - Capital Spares	$1,250,000	$1,250,000	$1,250,000	$1,250,000	$1,250,000
Substation Asset Mgmt Capital Maintenance	$5,550,000	$4,550,000	$4,050,000	$4,050,000	$4,050,000
Substation Rebuilds	$29,163,285	$31,580,000	$40,745,000	$32,100,000	$24,920,000
Total	**$35,963,285**	**$37,380,000**	**$46,045,000**	**$37,400,000**	**$30,220,000**

Projects comprising the Substation Rebuilds ER portion of the budget requests for the Substation Asset Condition Business Case are shown below. Note that substation rebuild projects typically take multiple years to design and construct. The substation rebuild projects shown below are shown in the year that the largest amount of budget is being requested.

2024	2025	2026	2027	2028
Lolo **Poleline (Prairie)***	Kooskia **Valley***	South Lewiston **Bronx*** Post Falls	Little Falls Northwest	**Ogara***

***Greenfield Substation**

Project prioritization is supported by the Engineering Roundtable (ERT) and substation subject matter experts for prioritization of work within this risk category. Project and funding levels are reviewed and approved by the ERT on an annual basis.

Fixing the equipment issues when they fail to function is necessary as is getting a good amount of life out of each piece of equipment until it reaches end of life. The balance is found by evaluating each piece of equipment and the substation as a whole when there are an overwhelming amount of equipment in a substation that has failed to function or is close to end of typical life.

Substation Asset Condition

2.2. Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

In a memo document dated December 27, 2017, Substation Performance Requirements were outlined by Rich Hydzik, Transmission Operations Engineer and Garth Brandon, then the Chief System Operator. The document identified issues which were integral to the reliable operation of the Avista electric system. This document is directly related to the Substation Asset Condition Business Case because it aims at addressing the identified issues.

Substation equipment requires regular maintenance and replacement to function reliably for good customer service. Substation designs and operation need to enable equipment maintenance and the replacement of equipment while still maintaining service to customers. Short momentary outages to allow switching may be required to allow maintenance activities to take place but extended outages that allow that occur from even day long maintenance activities are not acceptable customer service.

Avista System Operations is requesting that to properly operate the Avista electric system that substations have simplicity of switching and an intuitiveness in the layout of switching. The outage impacts of station work would be minimized. There is a need for consistency of switching and configuration from one station to another. Additionally, there is a desire for consistency in the equipment interface and how information is presented to operators.

2.3. Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$0	$0	$0	$0	$0
O&M		$0	$0	$0	$0	$0

No direct offsets are anticipated because rebuilding substations still requires monthly substation inspections and there are typically more pieces of equipment to inspect in a rebuilt substation than the previous substation.

2.4. Summarize in the table, and describe below the INDIRECT offset[4] (Capital and O&M) that result by undertaking this investment.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Substation Asset Condition

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	-	$0	$0	$0	$0	$0
O&M	Substation Rebuilds & Asset Management Offsets	$1,951,000	$1,951,000	$1,951,000	$1,951,000	$1,951,000

Station Rebuild (ER2204 Substation Rebuilds)
The indirect offsets assume that each substation has four pieces of equipment that require 'limp along' maintenance (power transformer, low voltage breaker recloser, high voltage breaker, and a voltage regulator). It is assumed that a Generation Production & Substation Support (GPSS) Serviceman spends approximately 10 hours each week driving to a substation, maintaining equipment to 'limp it along' instead of replacing it, and cleaning up.

1,040 hours (two locations * 10 hours of O&M * 52 weeks = 1,040 hours) of additional maintenance would be needed if these station rebuilds did not take place. Avista rebuilds two substations per year on average. If that work is not done, then 1 additional GPSS Serviceman will be needed to address the limp along maintenance needed to keep those stations in service. One additional Serviceman, will cost $176,800 annually (1 Journeyman Electrician * $85 loaded labor/hour *40 hours/week * 52 weeks). This figure does not include tools, materials and vehicle costs (miles and maintenance) used during this equipment maintenance.

Substation rebuilds are usually the result of many issues within a substation. There are often asset condition issues with several pieces of equipment, issues with safety, efficiency, environmental impacts where a rebuild is the only way to avoid risk from all of these factors. All new substation equipment means little maintenance other than the routine inspections, testing and maintenance. Servicemen will spend less time maintaining but will often spend more time completing inspections and testing because substation rebuilds usually result in a larger station with more equipment.

Station Rebuild (ER2215 Asset Maintenance)
This expenditure item is focused on projects that are requested and completed due to Asset Management issues like Asset Condition, Equipment Failures, Safety Issues, and Environmental Issues. Most are substation equipment replacements for equipment that has failed in service and are replaced on an emergency basis.

Assuming that a GPSS Serviceman spends approximately four hours each week driving to a substation, maintaining equipment to 'limp it along' instead of replacing it, and cleaning up. In 2020, 95 substations had Asset Management projects opened or completed. If none of these capital replacement projects were completed this equates to 19,760 hours (95 locations * 4 hours of O&M * 52 weeks = 19,760 hours of additional maintenance would be needed) spent on constantly limping equipment along. 9.5 additional GPSS Serviceman needed to complete this additional O&M work each year. 19,760 hours / 52 weeks / 40 hours = 9.5. Round this up to 10 Serviceman, this will cost $1,768,000 annually (10 Journeyman Electricians * $85 loaded labor/hour *40 hours/week * 52 weeks). This figure does not include tools, materials and vehicle costs (miles and maintenance) used during this equipment maintenance.

Risk of Outages due to not replacing equipment.
There is a risk of customer outages and an associated cost to customers for outages as a result of not replacing equipment when it is needing to be replaced. The cost turns out to not be material. Risk Cost = Prob of Failure * Prob (consequence) * Cost (consequence). Assuming 30 voltage regulator failures that result in customer outages per year. Also assuming ~1,000 customers per feeder. Risk Cost = 4% prob of failure * 1% catastrophic failure (customers out) * (1,000 customers * 4 hour outage * $116.15/hr) = $185.84 per outage * 30 failures per year = $5,575 per year

Substation Asset Condition

If a substation Transformer fails, assume 3,000 customers out (three feeders). Assume 1 transformer failure / year. Risk Cost = 0.4% prob of failure * 1% catastrophic failure * 3,000 customers * 8 hour outage * $116.15/hr = $111.50 per outage * 1 failure per year = $111.50 per year.

2.5. Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

The options for asset condition issues on the system are limited to do nothing, maintain current funding level and reduce the current funding level. Each of the options are discussed below:

Option 1: Do nothing - Not recommended because it would not be prudent to let the system deteriorate and not fix things in the substations that have failed. Obsolete and/or high loss equipment, deteriorated wood structures, and non-standard construction or equipment would remain in service until failure. Below are discussions of the consequences of not funding the individual ERs.

ER 2000. By not having spare equipment when things like a high voltage (>115kV) circuit breaker or power transformer fails suddenly reliability on the system would be tremendously hampered.

ER 2204. If rebuilding substations is not funded, ER2215 would need to dramatically increase in size to be able to respond to more individual equipment failures. Not rebuilding substations where the majority of equipment has not met its intended use or is obsolete will lead to an increase in O&M work in addition to the increase in expenditures for ER 2215 to respond to a whole host of equipment failures. Continuation of non-standard construction practices and configurations would lead to considerably slower and more dangerous working conditions for field crews.

ER 2215. By not funding the Asset Management section of the Asset Condition Business Case the substation equipment will limp along until the various equipment fails at any time and quite possibly catastrophically. This leads to significant customer outages (thousands of homes and businesses), safety situations for the public and employees. Customers could be out for days, months or even years because this ER is the location where funding for replacing the equipment when it fails comes from.

Option 2: Maintain current funding level – The current spending on the Asset Condition risk category is $13 million annually. Project prioritization is supported by the Engineering Roundtable and substation subject matter experts for prioritization of work within this risk category. The project and funding levels are reviewed on an annual basis.

Option 3: Reduce current Asset Condition capital investments. This option is not recommended. This option would lead to a reduction in the level of reliability and or operating flexibility that can be achieved by the transmission and distribution systems.

See the table below for a risk comparison between funding the business case and not funding the business case. Note that the Substation Asset Condition Business Case is projected to reduce the likelihood of an Environmental; Safety and Health to the Public; Legal, Regulatory, External Business Affairs; Safety and Health to Employees; and Customer Service and Reliability from once every 10 years to once every 50 years.

Substation Asset Condition

Unfunded Risk					
Likelihood of Event	**Environmental**	**Safety and Health: Public**	**Legal, Regulatory, External Business Affairs**	**Safety and Health: Employee**	**Customer Service and Reliability (# customers * duration of an outage)**
< Once / 10 years	Large volume transformer oil spill, hazardous waste cleanup, moderate to low volume or level of PCBs, minimal impact to waterways, repeated or moderate air emission exceedence	Potential for minimal or minor injury Outages and or equipment damage Public health infrastructure impact up to 24 hours	Could result in a sustained negative impact to local, online, or industrial relationships and / or national / global media coverage	Potential for minimal or minor injury Lost Time Incident and Severity Rate increases year over year	>7,500 Customer-hours
Revised Risk if funded/completed					
Likelihood of Event	**Environmental**	**Safety and Health: Public**	**Legal, Regulatory, External Business Affairs**	**Safety and Health: Employee**	**Customer Service and Reliability (# customers * duration of an outage)**
< Once / 50 years	Isolated spill with 0 to low level PCBs, no migration, air emission minor exceedence, standard clean-up	Potential for injury Public health infrastructure impact up to 8 hours	No likely impact on media or regulatory relationship.	Potential for injury	< 1,500 Customer-hours

Davenport Substation is a Substation Asset Condition job for 2023. Below the alternatives for this project are listed as examples for typical alternatives for Substation Asset Condition projects contained within the Substation Asset Condition Business Case.

Alt1: Status Quo
Do nothing and deal with failed plant and resultant outages as they come up.

Alt 2: Replace Individual Pieces of Equipment
Replace equipment on a case-by-case basis. Based on amount of equipment at site past end-of-life, multiple outages, mobilizations/de-mobilizations would result.

Alt3: Rebuild Davenport
Rebuild substation (either in place or with a short move to a greenfield site). Add three-phase SCADA and comms to site. Will help remote sectionalizing ability on transmission line (DGP-STR).

Substation Asset Condition

2.6. Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success for the asset condition business case can be measured ultimately by the lack of customer outages from substation failures. In addition, measuring the number of substation equipment failures would be another way of measuring success. By ensuring that the number of substation equipment failures is not dramatically increasing over time, customer outages in the future are likely not to be triggered.

The table below lists common substation equipment, the number of pieces of the equipment has in service and the average number of replacements per year for that equipment type. From the system count and the average replacements per year, an average levelized replacement length in years can be calculated. For comparison purposes, the number of pieces of equipment needed to be on a 20 year replacement cycle where 5% of the system for that equipment type is replaced is show in the table as well.

The table demonstrates the fact that not all equipment typically lasts the same period of time. Avista does not have an Asset Management strategy where pieces of equipment are replaced based on age. Instead each piece of equipment is evaluated as to whether it is meeting its required function. However, it is good practice to monitor what the average levelized replacement length is for each piece of major equipment to know if a bow wave of replacements are being created because of a low number of replacements are occurring.

Equipment Type	Avista System Count	Avista Average Replacement per Year (2018-2022)	Avista Average Levelized Replacement Length
Air Switches (>100kV)	1,081	26.80	40.0 years
Battery Banks	138	11.00	12.5 years
Circuit Breakers (<100kV)	508	13.20	38.5 years
Circuit Breakers (>100kV)	400	16.60	24.1 years
Circuit Switchers	126	2.75	45.8 years
Power Transformers	239	5.40	44.3 years
Voltage Regulators	1,118	61.60	18.1 years

2.7. Please provide the timeline of when this work is schedule to commence and complete, if known.

Projects within this business case are at all stages of work. There are continually several substation rebuild projects in scoping, design, construction, commissioning and closeout stages. Asset management replacements are being assessed, designed and constructed throughout the year, each and every year.

Substation Asset Condition

2.8. Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Each of the three ERs that are part of the Substation Asset Condition Business Case have different steering committes or governance teams.

ER 2000, the ER for Substation Spare Major Equipment is governed by the Apparatus Engineers and Substation Engineering Manager.

ER 2204, the Substation Rebuilds ER is governed by Engineering Rountable (ERT) Members: Substation Engineering, Transmission Engineering, Distribution Engineering, Communication Engineering, IT/ET Network Engineering, System Planning, and System Operations.

ER 2215, the Substation Asset Management ER is governed by the Substation Maintenance Engineers, Distribution Area Engineers, Electric Shop Servicemen, Distribution Area Servicemen, and Substaion Engineering Manager.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *<Business Case Name>* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

DocuSigned by:

Signature:	Glenn J Madden	Date:	May-12-2023 | 5:31 PM PDT
Print Name:	7D4B3DE5CBD846B... Glenn Madden		
Title:	Substation Engineering Manager		
Role:	Business Case Owner		

DocuSigned by:

Signature:	Vern Malensky	Date:	May-14-2023 | 6:00 PM PDT
Print Name:	06C4FF5AB09E40B... Vern Malensky		
Title:	Electrical Engineering Director		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Substation – Asset Condition Program

1.0 CHANGE REQUEST #04 – 202312

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
12-2023	Revised Cost	04	$38,150,000	-$2,100,000		
10-2023	Revised Cost	03	$40,650,000	-$2,500,000	-$2,500,000	$38,150,000
09-2023	Revised Cost	02	$36,850,000	$3,800,000	$3,800,000	$40,650,000
07-2023	Scope Change	01	$48,350,000	-$11,500,000	-$11,500,000	$36,850,000

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
07-2023	Scope Change	$1,951,000	$1,951,000	$50,185,897	$50,185,897
09-2023	Revised Cost	$1,951,000	$1,951,000		
10-2023	Revised Cost	$1,951,000	$1,951,000		
12-2023	Revised Cost	$1,951,000	$1,951,000		

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	$47,200,000	$37,500,000*	$1,951,000	$1,951,000	$30,327,681	$23,436,681
2025	$49,650,000	$38,500,000*	$1,951,000	$1,951,000	$56,455,721	$49,690,585
2026	$30,650,000	$39,000,000*	$1,951,000	$1,951,000	$52,370,000	$10,870,000
2027	$33,200,000	$29,500,000*	$1,951,000	$1,951,000	$58,598,000	$51,690,000
2028		$24,500,000*	$1,951,000	$1,951,000		

*From New 5-year Business Case Request 2024-2028. This includes all business case changes not just this in-year request.

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Substation – Asset Condition Program

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

07-2023: The Metro 115kV Station Rebuild project was initially funded from the Substation – Station Rebuilds Program Business Case. Due to its large scope and cost, the Metro project has become its own Business Case as of March 2023. This fund change is now requested to move budgeted dollars from Substation – Station Rebuilds Program Business Case to the Metro 115kV Station Rebuild Business Case.

See the corresponding documentation for the Metro 115kV Station Rebuild Business Case fund request.

09-2023: Several property parcels have been purchased in 2023. The original budget for the property (totalling $2M) has been spent and there are more properties that we have been able to negotiate a purchase for this year.

10-2023: Metro Substation project dollars were transferred to the Metro Sub Rebuild business case in September. This credit to the Substation – Asset Condition business case was larger than expected (a total of $3.7M, $2.5M over expected). This give back reflects this change.

12-2023: Rathdrum capacity project was curtailed and budget needed was lower than initially thought (-$1M). Property purchase for Havana/Dalke property was delayed until 2024 (-$500k). Tightened up the Contingency for all Asset Management/Failed Equipment Budget items.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Brian Chain	BC Owner	DocuSigned by: Brian Chain C4012FF13CFC491...	Dec-15-2023 | 6:33 AM PST
Vern Malensky	BC Sponsor	DocuSigned by: Vern Malensky 06C4FF5AB09E40B...	Dec-15-2023 | 7:10 AM PST
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Technology Failed Assets

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Technology Failed Assets business case was established and consists of in-portfolio technology assets for rapid replacement of assets as they fail and when repairs are not feasible. A technology inventory is maintained to quickly restore business functionality. They can include, but not be limited to laptops, mobile phones and tablets, printers, field area network (FAN) equipment, monitors, audio-visual equipment, routers, switches, servers and fiber cable. The cost of each technology solution will vary depending on the type of asset. Additional impacts to budget allocation in this business case are scope of failure, required lead time, and location.

The Technology Failed Assets business case was originally funded for 2023 at $660,000. The demand for Technology Failed Assets is hard to control and current trends indicate that the Company is running assets longer than recommended. In 2023, this business case transferred approximately $1.4M, which represents a variance of approximately $870k of over transfers. A variety of factors contributed to additional transfer-to-plant amount:

- An increase in technology failure rates (laptops, mobile phones and tablets, printers) due to assets running longer than recommended.
- To supply inventory spares for field area network (FAN) equipment.
- The completion of the Rugged Refresh project, where remaining inventory transferred to this business case.
- Antenna failures at Mt. Emily and Mt. Scott.
- Audio Visual equipment replacement for the Auditorium and Conference Room 128.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

All projects contained within ET business cases are governed by a steering committee and thus any changes to scope, schedule, or budget are approved by that steering committee and business case governance for prudency. Therefore, any additional costs to the project were prudently documented and approved. Please see the following Capital Planning Group change request documents that represent changes to the plan from the filed general rate case amount. These change requests represent additional spend that was needed, that will result in additional transfers-to-plant and go into more details regarding the reasons for the additional funding:

Request – ITFA CR01	AV, CR128 Screen Replacement Avidex	$250,000
Request – ITFA CR02	Mt. Scott Antenna failures, HVAC at Cabinet Gorge, MW, PC/Laptop/Tablet	$171,800
Request – ITFA CR03	Apple iDevice replacement, Network & Fan, GE SONET and NOKIA Spares, PC/Laptop/Tablet, Rugged Refresh Project Transfer	$250,000
Request – ITFA CR04	Auditorium Project Taxes, Comms & LMR Mount Scott additional equipment needed, Network & Fan failures, Printer Failures higher than anticipated, PC/Laptop/Tablet T480 failures	$110,000
Request – ITFA CR05	Auditorium Programming, Pullman Tropos Devices (Expense to Capital), Network UPS and Server Failures, Higher than Anticipated Printer Failures, Unanticipated Deficiencies in Cell Boosters in Two Areas.	$162,000
Request – ITFA CR06	Mt. Emily Tower Mapping and Load Analysis, PC/Laptop/Tablet T480 Failures, Apple iDevice Replacement, Printer Failures	$50,000
		$993,800

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no direct offsets in the Technology Failed Assets business case, though the ability to replace failed assets in a timely manner will prevent extended impacts to employee productivity. Therefore, not funding a failed asset replacement inventory would result in an increase to O&M costs. Investments in these technology asset replacements provide indirect savings to our customers by cost avoidance related to downtime issues and loss of productivity due to potentially implementing manual business processes. Without spare inventory on hand, this would increase the amount of time to resolve these breakdown issues, thereby reducing the efficiency of employees as well as our infrastructure systems. The amount of indirect savings would depend on the site and associated business process systems impacted by failure. Current trends indicate that the Company is running assets longer than recommended.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

DocuSigned by:
X Dave Husted
798843B6996642A...

DIRECTOR SIGNATURE:

DocuSigned by:
X Alexis Alexander
EA27BABA767F467...

Technology Failed Assets

1.0 CHANGE REQUEST #CR01 – 05.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
05-2023	*Revised Cost*	CR01	$556,200	$250,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	**Request Type**	**Budgeted Savings /Offsets[1]**	**Revised Savings /Offsets**	**Currently Planned TTP[2]**	**Revised TTP**
05-2023	Revised Cost	$100k-$10M		$556,200	$806,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	**Budgeted Approved Amount[3]**	**Updated Funding Anticipated as a result of request**	**Budgeted Benefits /Offsets[4]**	**Revised Benefits /Offsets**	**Budgeted TTP[5]**	**Revised TTP**
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Technology Failed Assets

Increases to this business case in 2023 do not have an impact on 2024 or any out years.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Technology Failed Assets Business Case is seeking additional funding in the total amount of $250,000 to align with forecasting for Q2. This business case is a program of blanket technology projects that transfers to plant monthly. Quarterly forecasts capture changes in transfers to plant based on trends of fulfillment requests. The targeted forecast for 2023 is $1.2 million. This level of funding is critical to maintain an inventory of in-portfolio assets to be available for rapid replacement during failures or unplanned outages (i.e. laptops, mobile phones, field area network equipment, etc.). The funding amounts within this program undergo regular review to balance the asset failure forecast within the predetermined budget allocations. Since technology asset failures will happen across Avista's territory, having budget allocation available to quickly replace a failed asset is critical to the daily operations of the Company.

Based on the data, two ITFA Blankets, AV & PC/laptop/tablet, have seen an increase in failure rates due to employees coming back into the facilities. (See 1-2) The other increase is in the Network and FAN Blanket from the spare inventory process. (See 3)

1. The ITFA AV Blanket has been capturing failures in conference/meeting rooms, including the Auditorium, as people have been using these spaces much more in 2023 than in the past three years. This usage has brought to our attention the failures of the AV devices in those spaces that aren't being addressed in refresh projects.

2. The ITFA PC/laptop/tablet Blanket has also seen an uptick in failures as people have been returning to the building. These AV & PC/laptop/tablet failures account for approximately $130k of the CPG request.

3. Another area that is seeing an increase is the ITFA Network & FAN Blanket, which is due to the spare unit process coming from project work. Network equipment tends to have a higher cost per unit than most of the other blanket device types and can vary. The spare requests are averaging $20k and are expected to cost $60k through Q2.

4. Finally, outlying critical failures, like HVAC at Cabinet MW are expected to cost $60k.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Technology Failed Assets

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Kaitlyn Richardson	BC Owner	DocuSigned by: Kaitlyn Richardson CD813F49C5C9403...	May-15-2023 | 8:08 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	May-15-2023 | 2:13 PM PDT
	Steering Committee (If applicable)		

Technology Failed Assets

1.0 CHANGE REQUEST #CR02 – 06.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
06-2023	*Revised Cost*	CR02	$806,200	$171,800		
05-2023	*Revised Cost*	CR01	$556,200	$250,000	$250,000	$806,200
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

Request Date	Offsets Impact			TTP Impact	
	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
06-2023	Revised Cost	$100k-$10M		$806,200	$978,000
05-2023	Revised Cost	$100k-$10M		$556,200	$806,000
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

Year	Funding Impact		Offsets Impact		TTP Impact	
	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Technology Failed Assets

Increases to this business case in 2023 do not have an impact on 2024 or any out years.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Technology Failed Assets Business Case is seeking additional funding in the total amount of $171,800 to align with forecasting for Q3. This business case is a program of blanket technology projects that transfers to plant monthly. Quarterly forecasts capture changes in transfers to plant based on trends of fulfillment requests. The targeted forecast for 2023 is $1.5 million. This level of funding is critical to maintain an inventory of in-portfolio assets to be available for rapid replacement during failures or unplanned outages (i.e. laptops, mobile phones, field area network equipment, etc.). The funding amounts within this program undergo regular review to balance the asset failure forecast within the predetermined budget allocations. Since technology asset failures will happen across Avista's territory, having budget allocation available to quickly replace a failed asset is critical to the daily operations of the Company.

The Communications and Land Mobile Radio (LMR) Blanket will capture antenna failures at Mt. Scott (See #1). Another failure is urgent to replace the HVAC at Cabinet Gorge MW and is being captured under the Network and Field Area Network (FAN) Blanket (See #2). The PC/Laptop/Tablet Blanket have failures of equipment that are currently on order (See #3).

1. The ITFA Communications and Land Mobile Radio (LMR) Blanket is addressing Mt. Scott antenna failures. The cost for 2 units and the labor to replace them is estimated at $50,000. Additionally, two spares are being purchased at $13,800.
2. The ITFA Network & FAN Blanket is being used to replace a failed HVAC at Cabinet Gorge MW. The equipment cost and labor are estimated at $20,000.
3. The ITFA PC/Laptop/Tablet Blanket has $88,000 of equipment on order for identified failures (see diagram below for breakout of current Laptop Failure Risks by Model).

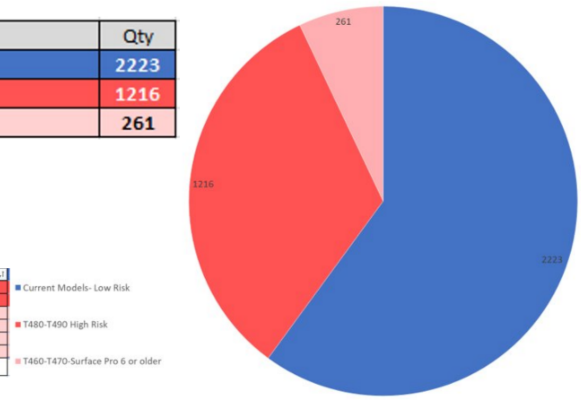
[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Technology Failed Assets

Laptops Failure Risk by Model

Laptops Failure Risk by Model	Qty
Current Models- Low Risk	2223
T480-T490 High Risk	1216
T460-T470-Surface Pro 6 or older	261

Qty	Device Model
1081	ThinkPad T480
135	ThinkPad T490
50	ThinkPad T460
130	ThinkPad T470
70	Surface Pro
11	Virtual Machine
1477	**Higher Failure Risk**



22 AVISTA

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Kaitlyn Richardson	BC Owner	DocuSigned by: Kaitlyn Richardson CD813F49C5C9403...	Jun-16-2023 | 4:09 PM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Jun-16-2023 | 4:11 PM PDT
	Steering Committee (If applicable)		

Technology Failed Assets

1.0 CHANGE REQUEST #CR03 – 07.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
07-2023	*Revised Cost*	CR03	$978,000	$250,000		
06-2023	*Revised Cost*	CR02	$806,200	$171,800	$171,800	$978,000
05-2023	*Revised Cost*	CR01	$556,200	$250,000	$250,000	$806,200
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
07-2023	Revised Cost	$100k-$10M		$978,000	$1,228,000
06-2023	Revised Cost	$100k-$10M		$806,200	$978,000
05-2023	Revised Cost	$100k-$10M		$556,200	$806,000
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Technology Failed Assets

Increases to this business case in 2023 do not have an impact on 2024 or any out years.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Technology Failed Assets (ITFA) Business Case is seeking additional funding in the total amount of $250,000 to align with forecasting for Q3. This business case is a program of blanket technology projects that transfers to plant monthly. Quarterly forecasts capture changes in transfers to plant based on trends of fulfillment requests. The targeted forecast for 2023 is $1.35 million. Thus, at this point in time the ITFA business case will be seeking another request to align with the annual forecast of $1.35M of approximately $122k. This level of funding is critical to maintain an inventory of in-portfolio assets to be available for rapid replacement during failures or unplanned outages (i.e., laptops, mobile phones, field area network equipment, etc.). The funding amounts within this program undergo regular review to balance the asset failure forecast within the predetermined budget allocations. Since technology asset failures will happen across Avista's territory, having budget allocation available to quickly replace a failed asset is critical to the daily operations of the Company.

This request covers forecasted amounts based on year-to-date failure rate data to the best of our knowledge at this point in time for Q3 and Q4 that includes the following:

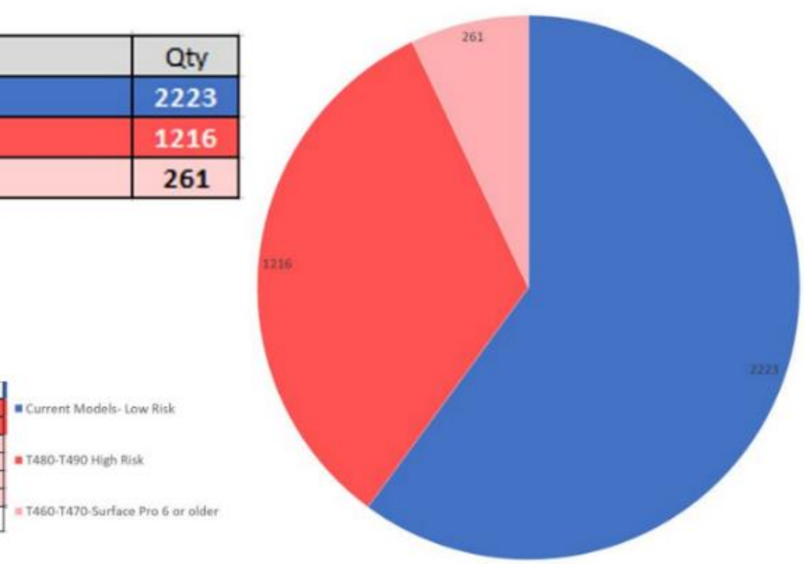
1. The ITFA Apple iDevice Replacement Blanket is purchasing $58,000 of spare inventory to meet the normal failure rate of one hundred (100) devices per year.
2. The ITFA Network & FAN (Field Area Network) Blanket is requesting a total of $154,000.
    a. Purchasing GE SONET and NOKIA equipment to replenish spare inventory due to failure. The equipment cost and labor are estimated at $54,000.
    b. Additionally, projects delivering new network assets require ITFA to stock spare inventory based on projected failure rates. The project delivery requests average one per month at an average cost of $20,000 each ($20,000 x 5 remaining months = $100,000).
3. The ITFA PC/Laptop/Tablet Blanket is requesting $38,000.
    a. The Rugged Refresh project is closing and transferring $10,000 of spare inventory (docking stations) to ITFA.
    b. There is $28,000 forecasted for high-rate laptop failures based on high failure rates of T480 laptops that have been in service for over five years.

    Please see the diagram below that details out the risks of our failed laptops.

Laptops Failure Risk by Model

Laptops Failure Risk by Model	Qty
Current Models- Low Risk	2223
T480-T490 High Risk	1216
T460-T470-Surface Pro 6 or older	261

Qty	Device Model
1081	ThinkPad T480
135	ThinkPad T490
50	ThinkPad T460
130	ThinkPad T470
70	Surface Pro
11	Virtual Machine
1477	**Higher Failure Risk**



[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Kaitlyn Richardson	BC Owner	DocuSigned by: Kaitlyn Richardson	Jul-17-2023 | 4:54 PM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Jul-19-2023 | 8:46 AM PDT
	Steering Committee (If applicable)		

Technology Failed Assets

1.0 CHANGE REQUEST #CR04 – 09.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
09-2023	*Revised Cost*	CR04	$1,228,00	$110,000		
07-2023	*Revised Cost*	CR03	$978,000	$250,000	$250,000	$1,228,000
06-2023	*Revised Cost*	CR02	$806,200	$171,800	$171,800	$978,000
05-2023	*Revised Cost*	CR01	$556,200	$250,000	$250,000	$806,200

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
09-2023	Revised Cost	$100k-$10M		$1,228,000	$1,338,000
07-2023	Revised Cost	$100k-$10M		$978,000	$1,228,000
06-2023	Revised Cost	$100k-$10M		$806,200	$978,000
05-2023	Revised Cost	$100k-$10M		$556,200	$806,000

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Technology Failed Assets

Increases to this business case in 2023 do not have an impact on 2024 or any out years.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Technology Failed Assets (ITFA) Business Case is seeking additional funding in the total amount of $110,000 to align with forecasting for Q4. This business case is a program of blanket technology projects that transfers to plant monthly. Quarterly forecasts capture changes in transfers to plant based on trends of fulfillment requests. The targeted forecast for 2023 is $1.34 million. Thus, the ITFA business case will seek another request to align with the annual forecast of $1.34M of approximately $110,000. This level of funding is critical to maintain an inventory of in-portfolio assets to be available for rapid replacement during failures or unplanned outages (i.e., laptops, mobile phones, field area network equipment, etc.). The funding amounts within this program undergo regular review to balance the asset failure forecast within the predetermined budget allocations. Since technology asset failures will happen across Avista's territory, having budget allocation available to quickly replace a failed asset is critical to the daily operations of the Company.

This request covers forecasted amounts based on year-to-date failure rate data and the additional cost of sparing being requested for Projects to the best of our knowledge at this point in time for Q4 that includes the following:

1. The Mission Auditorium projector lift & screen failed and the replacement project is projecting over budget by $5,000.
   a. Professional services have come in higher since taxes were not originally factored into the amount.
2. The ITFA Comms & LMR Device Replacement blanket is requesting an additional $15,800 to cover additional costs for:
   a. $5,800 for outage restoration work at the Mount Scott (Oregon) network/communication site, unexpected product and professional services costs to insert a new ice shield to protect the equipment.
   b. $10,000 for replacement of spare inventory. The need is due to a higher than anticipated failure rate.
3. The ITFA Network & FAN (Field Area Network) Blanket is requesting a total of $28,200.
   a. Projects delivering new network assets require ITFA to store spare inventory based on projected failure rates.
4. The ITFA Printer Replacement Blanket is requesting $11,000.
   a. $11,000 for replacement of spare inventory. The need is due to a higher than anticipated failure rate.
5. The ITFA PC/Laptop/Tablet Blanket is requesting $50,000.
   a. $50,000 for replacement of spare inventory. The need is due to a higher than anticipated T480 failure rate. T480 model laptops have been in service for over five years.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Kaitlyn Richardson	BC Owner	DocuSigned by: Kaitlyn Richardson CD818F49C5C9403...	Sep-20-2023 | 7:39 AM PDT
Jim Corder	BC Sponsor	DocuSigned by: Jim Corder 7002E4872104449...	Sep-20-2023 | 8:58 AM PDT
	Steering Committee (If applicable)		

Technology Failed Assets

1.0 CHANGE REQUEST #CR05 – 10.23

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
10-2023	*Revised Cost*	CR05	$1,338,000	$162,000		
09-2023	*Revised Cost*	CR04	$1,228,00	$110,000	$110,000	$1,338,000
07-2023	*Revised Cost*	CR03	$978,000	$250,000	$250,000	$1,228,000
06-2023	*Revised Cost*	CR02	$806,200	$171,800	$171,800	$978,000
05-2023	*Revised Cost*	CR01	$556,200	$250,000	$250,000	$806,200

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
10-2023	Revised Cost	$100k-$10M		$1,338,000	$1,500,000
09-2023	Revised Cost	$100k-$10M		$1,228,000	$1,338,000
07-2023	Revised Cost	$100k-$10M		$978,000	$1,228,000
06-2023	Revised Cost	$100k-$10M		$806,200	$978,000
05-2023	Revised Cost	$100k-$10M		$556,200	$806,000

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Technology Failed Assets

Increases to this business case in 2023 do not have an impact on 2024 or any out years.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Technology Failed Assets (ITFA) Business Case is seeking additional funding in the total amount of $162,000 to align with forecasting for Q4. This business case is a program of blanket technology projects that transfers to plant monthly. Quarterly forecasts capture changes in transfers to plant based on trends of fulfillment requests. The targeted forecast for 2023 is $1.48 million. Thus, the ITFA business case will seek another request to align with the annual forecast of $1.48 million of approximately $162,000. This level of funding is critical to maintain an inventory of in-portfolio assets to be available for rapid replacement during failures or unplanned outages (i.e., laptops, mobile phones, field area network equipment, etc.). The funding amounts within this program undergo regular review to balance the asset failure forecast within the predetermined budget allocations. Since technology asset failures will happen across Avista's territory, having budget allocation available to quickly replace a failed asset is critical to the daily operations of the Company.

This request covers forecasted amounts based on year-to-date failure rate data and the additional cost of sparing being requested for Projects to the best of our knowledge at this point in time for Q4 that includes the following:

1. The ITFA Tropos Network Replacement project is requesting $70,000.

   The project was originally classified as Expense, but through research it was discovered that the Tropos devices being used had gone through the Avista Salvage procedures in place at the time they were removed from the field and stored. This allowed the Tropos devices to be capitalized for future use in the field. The project has been changed from an Expense Project to a Capital Project and is requesting Capital funding to replace these failed assets for:
   a. The use of 16 of the now capitalizable Tropos devices at $60,000 to replace the failed assets.
   b. The additional labor needed to develop a monitoring and maintenance plan for Operational handoff in this area for these devices estimated at $10,000.
2. The ITFA Network, FAN, and Storage Device Replacement blanket is requesting an additional $40,000.
   a. The Orofino Uninterruptible Power Supply (UPS) device used to maintain power failed with no spares available.
   b. An out of warranty Blade Server in the Virtual Desktop Infrastructure (VDI) Environment failed with no spare parts available.
3. The ITFA Printer Replacement Blanket is requesting $40,000.
   a. Continued higher than anticipated failure rates of printers are being seen due to the return-to-work efforts.
4. The Mission Auditorium Projector Lift & Screen project to replace the failed projector did not include the work to program the projector screen with raise and lower functionality into the existing Crestron Systems controls for the projector screen.
   a. Professional services and labor to incorporate this functionality is estimated at $4,000.
5. The ITFA Repeater blanket is requesting $8,000 for unanticipated Cell Phone Signal Booster failures at both the Dollar Road facility and for the Construction Project Coordinators (CPC's) at the Mission Campus.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Technology Failed Assets

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Kaitlyn Richardson	BC Owner	DocuSigned by: CD813F49C5C9403...	Oct-17-2023 | 8:25 AM PDT
Wayne Manuel	BC Sponsor	DocuSigned by: Wayne Manuel F1A34ACB278F4F7...	Oct-18-2023 | 6:38 AM PDT
	Steering Committee (If applicable)		

Technology Failed Assets

1.0 CHANGE REQUEST #CR06 – 11.23

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
11-2023	*Revised Cost*	CR06	$1,500,000	$50,000		
10-2023	*Revised Cost*	CR05	$1,338,000	$162,000	$162,000	$1,500,000
09-2023	*Revised Cost*	CR04	$1,228,00	$110,000	$110,000	$1,338,000
07-2023	*Revised Cost*	CR03	$978,000	$250,000	$250,000	$1,228,000
06-2023	*Revised Cost*	CR02	$806,200	$171,800	$171,800	$978,000
05-2023	*Revised Cost*	CR01	$556,200	$250,000	$250,000	$806,200

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
11-2023	Revised Cost	$100k-$10M		$1,500,000	$1,540,000
10-2023	Revised Cost	$100k-$10M		$1,338,000	$1,500,000
09-2023	Revised Cost	$100k-$10M		$1,228,000	$1,338,000
07-2023	Revised Cost	$100k-$10M		$978,000	$1,228,000
06-2023	Revised Cost	$100k-$10M		$806,200	$978,000
05-2023	Revised Cost	$100k-$10M		$556,200	$806,000

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5-year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5-year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

Increases to this business case in 2023 do not have an impact on 2024 or any out years.

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Technology Failed Assets

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The Technology Failed Assets (ITFA) Business Case is seeking additional funding in the total amount of $50,000 to align with forecasting for Q4. This business case is a program of blanket technology projects that transfers to plant monthly. Quarterly forecasts capture changes in transfers to plant based on trends of fulfillment requests. The targeted forecast for 2023 is $1.55 million. Thus, the ITFA business case will seek another request to align with the annual forecast of $1.55 million of approximately $50,000. This level of funding is critical to maintain an inventory of in-portfolio assets to be available for rapid replacement during failures or unplanned outages (i.e., laptops, mobile phones, field area network equipment, etc.). The funding amounts within this program undergo regular review to balance the asset failure forecast within the predetermined budget allocations. Since technology asset failures will happen across Avista's territory, having budget allocation available to quickly replace a failed asset is critical to the daily operations of the Company.

This request covers forecasted amounts based on year-to-date failure rate data and the additional cost of sparing being requested for Projects to the best of our knowledge at this point in time for Q4 that includes the following:

1. The ITFA Comms & LMR Device Replacement blanket is requesting $10,000.

   The La Grande, OR Mt. Emily Antenna was damaged by ice fall this past winter.
   In 2023 we need to do the following work in preparation for the replacement antenna:

   a. Tower Mapping - estimated at $6,000 - contractor Day Wireless (2023 work)
   b. Tower Load Analysis - requested by Tower Owner Union County - estimated at $4,000 - contractor NWTE (2023 work)

2. The ITFA PC Laptops Tablets Replacement blanket is requesting an additional $10,000.

   The need is due to a higher than anticipated T480 failure rate. T480 model laptops have been in service for over five (5) years.

3. The ITFA Apple iDevice Replacement blanket is requesting $20,000.

   The ITFA Apple iDevice Replacement Blanket is purchasing $20,000 of spare inventory to meet the normal failure rate of one hundred (100) devices per year.

4. The ITFA Printer Replacement blanket is requesting $10,0000.

   Continued higher than anticipated failure rates of printers are being seen due to the return-to-work efforts.

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Technology Failed Assets

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Kaitlyn Richardson	BC Owner	DocuSigned by: Kaitlyn Richardson CD813F4905C9403...	Nov-07-2023 | 1:05 PM PST
Alexis Alexander	BC Sponsor	DocuSigned by: Alexis Alexander EA27BABA767F467...	Nov-13-2023 | 5:14 PM PST
	Steering Committee (If applicable)		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Telematics 2025

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The original project scope of the Telematics 2025 business case included funding for connecting Avista fleet vehicle location information to our customer facing systems. After progressing through the other segments of the project, the team reevaluated the feasibility of this functionality and the team reconnected with System Architects and determined that other interfacing systems were not in place to make it possible for fleet vehicle location data to be customer facing as had originally been envisioned by the project in the original development of the project scope and plan.

Another portion of the scope of this project was the automation of vehicle use supplied by the telematics system combined with timekeeping information to determine allocation of the vehicle charges. The development work continued for this scope item, however, the development work had to be paused in early 2023 due to resource constraints and priorities but restarted in the 3rd quarter of 2023. Development work was not completed in 2023 and will continue into 2024, with anticipated transfer to plant in 2024.

These two items together resulted in transfer to plant (TTP) timing changes for this business case.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

This phase of the project meets monthly with a steering committee that reviews change orders and impacts to the budget. Due to the reduction in scope, we completed a Capital Planning Group (CPG) funds change request that released previously allocated funding.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There are no documented offsets for the portion of the overall project that has been removed.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Gregory Loew

DIRECTOR SIGNATURE:

X Kelly Magalsky

1.0 CHANGE REQUEST #1

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
8/10/2023	*Revised Cost*	1	808,250	-608,000		200,250
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
8/10/23	Revised Cost	0	0	900,000	0
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This should not be considered approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024	0	0				200,250
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The reason for the fund request change is that the scope of Telematics 2025 has shrunk and no longer will include work to interface with Salesforce. This change is due to the inability to of our existing work order management system to function in such a manner that it would allow data and decisions to be consistent across all of the dispatching for our customer facing individual contributors, crews and other front line individuals.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Greg Loew	BC Owner	Gregorymloew	8/10/23
	BC Sponsor	Kelly Magalsky	8/10/2023
n/a	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Transmission Minor Rebuild

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The inspection protocols associated with the Transmission Minor Rebuild Business Case identify asset problems; that, if left unaddressed, will lead to near-term catastrophic structural failures. These structural failure conditions, if left unaddressed, will result in an increased risk of system failures, customers outages, and wildfires. This includes the follow-up work to Wood Pole Inspections, Aerial Patrol inspections, Ad Hoc ground inspections, and Air Switch Reliability complaints.
More specifically, this Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the North American Electric Reliability Corporation (NERC) Reliability Standard FAC-501-WECC-1 as applied through Avista's Transmission Maintenance Inspection Program (TMIP). This standard mandates that specific Transmission lines be inspected annually and assessed for corrective actions to be implemented to remedy any system performance deficiencies. The TMIP applies the same inspection methodology to the entire Avista system with the understanding that only a portion of the mitigation work is recognized as Mandatory and Compliance. The remaining work undertaken within this Business Case is recognized as Customer Requested, Failed Plant and Asset Condition.
Transfer to Plant Variance (over) was due to additional work identified via drone patrols. These ad hoc Patrol Inspections revealed defects that were determined to need immediate (within 6 months) attention.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Additional spend (cost overruns) in this Business Case was monitored through the year and reviewed at the Electrical Engineering Budget Committee each month. As cost overruns (additional work scope in this case) were identified, a decision was made to request additional funds through the CPG process. Attached is the formal request for additional funding.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There is no change in Offsets.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

x **APPROVED** By Ken Sweigart at 1:28 pm, Feb 21, 2024

DIRECTOR SIGNATURE:

x

Transmission Minor Rebuild

1.0 CHANGE REQUEST #01 – OCTOBER 2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
10-10-2023	*Scope Change*	01	$3,343,420	$2,250,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
10-10-2023	Scope Change			$3,343,420	$5,593,420
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Transmission Minor Rebuild

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

This request breaks down into three areas of the Transmission Minor Rebuild BC:

- HOT-NOX#2 ($1M): This project was identified by drone patrol and required immediate attention. Earlier (August) BCFCR was made for $750k with the CPG requesting TLD to fund internally (see below for details).
- MTR-SUN ($1M): The project Scope and Approach morphed to accommodate the high profile and delicate political nature of the project location. This project was originally budgeted at a much lower amount; and, given its final form, could easier have priginated under the Transmission Major Rebuild – Asset Condition BC (see below for details).
- Southern Area Patrol Mitigations: This project is estimated to at $250k and will be issued in October.

The entirety of this request will be balanced with releases from the following BC's:

- Transmission Major Rebuild – Asset Condition: $1.5M
- Low Priority Ratings Mitigation: $500k
- Transmission Performance & Capacity: $250k

Below is a summary of Noxon-Hot Springs 230kV Transmission Line facilities needing immediate attention to prevent anticipated failure as reported by Sandpoint Operations. Outage has been requested and approved starting 9/11/2023 contingent upon funds approval.

All –

Here's my current scope of work on HOT-NOX #2.

Total of 22 structures I'm drawing up, expecting that with our resources in our outage window we'll get 17-18 of them.

Due to drive time and access, very rough order of magnitude estimate is $40k per structure, plus some other extraneous work sets us at ~$1M.

Also attached is some select pictures of the condition of structures.

This is set up under project # 42304221, labor can be charged to 1027297924, material when I get it in will be 1027297931.

Questions let me know

Thanks

Will

Structure	Issue	Mitigation			
0/6	WP holes top near static	O-S			Top priority highlighted
1/4	broken insulator	replace glass			
3/5	pole burn pocket at guy	patch for now			
4/7	split arm	HDA-S			

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Transmission Minor Rebuild

5/8	chipped insulator	replace glass			
7/2	osprey nest over center phase	knock nest			
9/5	WP holes outside corner near top	O-S			
10/9	osprey nest	knock nest			
12/2	split arm	H-S			
12/4	nest	knock nest			
17/6	WP holes pole	H-S			
21/4	WP holes pole	H-S			
24/6	light split arm	H-S			
26/7	split arm	H-S			
27/3	light split arm	H-S			
28/2	split arm	H-S			
33/1	light split arm	H-S			
34/5	arm delam by south pole	H-S			
35/1	split arm	H-S	Landing, dirt work, Tx Xing		
36/6	split arm	H-S			
37/2	split arm	H-S			
37/7	split arm	H-S			
38/1	split arm	H-S			
42/8	split arm	H-S			
43/5	light split arm	H-S			
50/7	xbrace burnt through	H-S			
64/7	light split arm	H-S	road wor k		
66/4	split arm, rough poles	H-S			

0/6

Transmission Minor Rebuild

Transmission Minor Rebuild

4/7 

Transmission Minor Rebuild

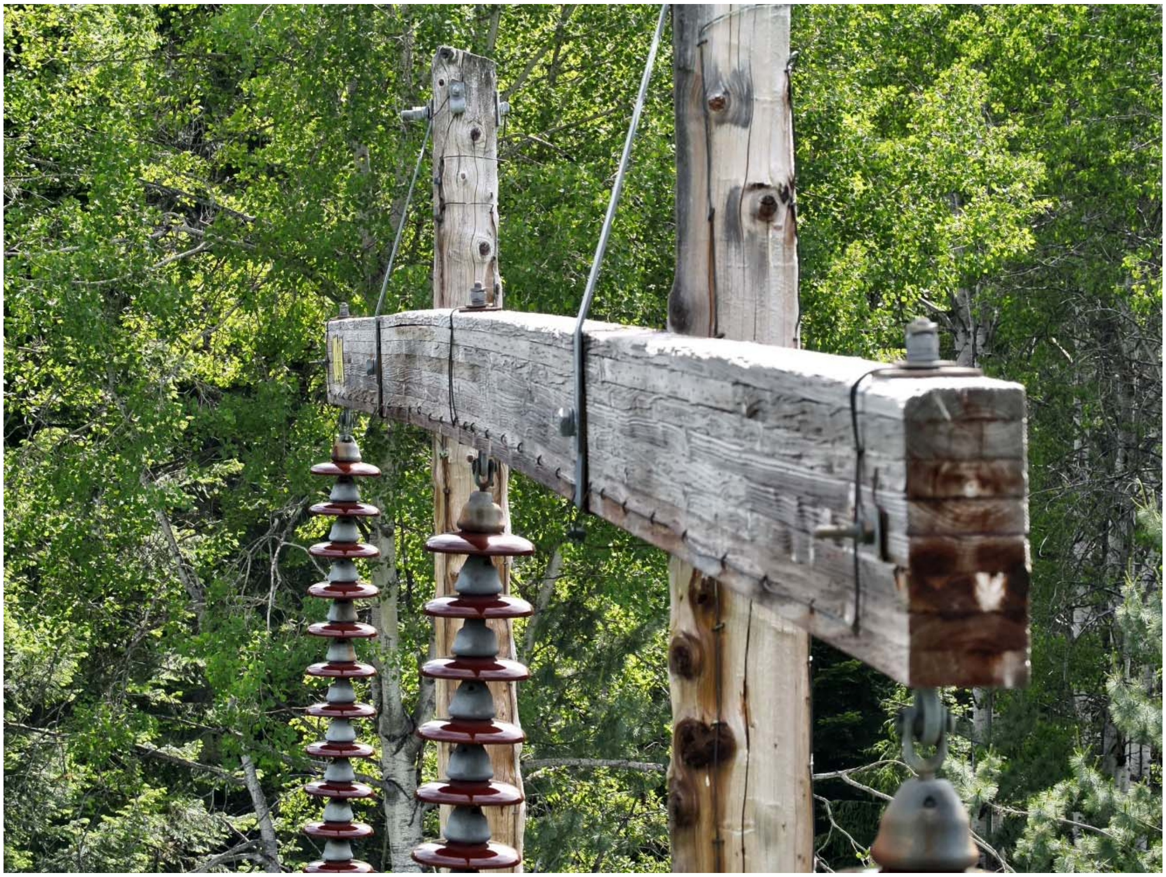
12/2

Transmission Minor Rebuild

17/6

Transmission Minor Rebuild

21/4

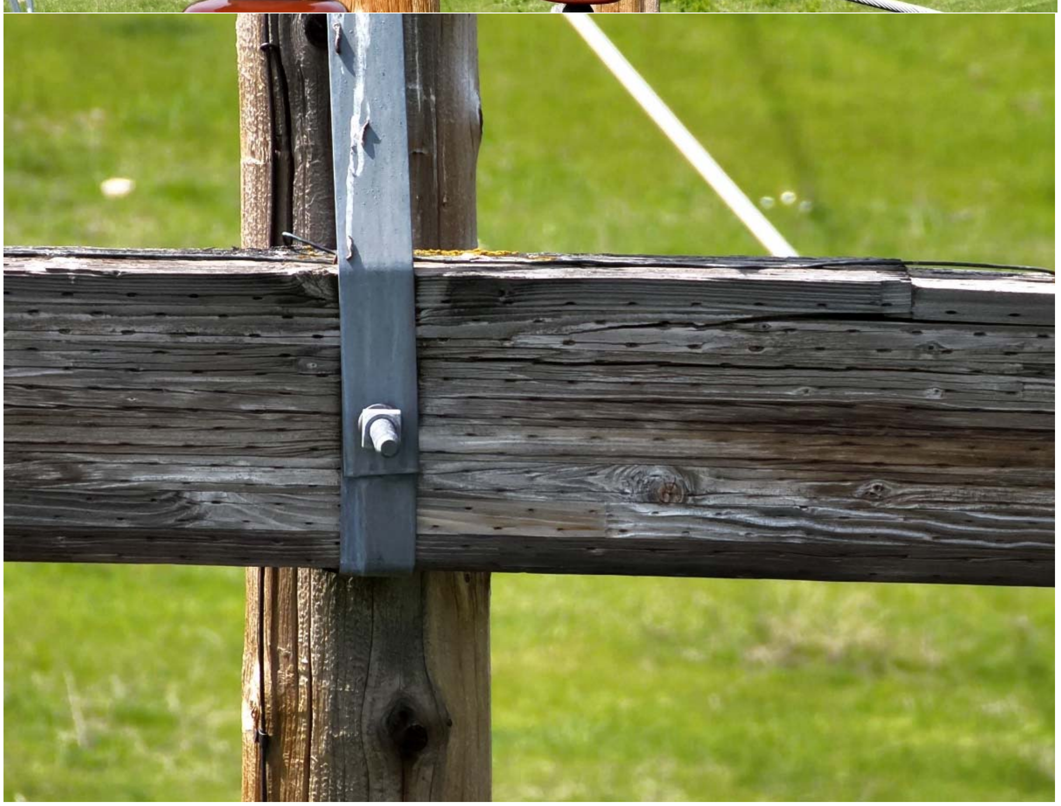


Transmission Minor Rebuild

26/7

Transmission Minor Rebuild

27/3



Transmission Minor Rebuild

28/2

Transmission Minor Rebuild

34/5

Transmission Minor Rebuild

35/1

Transmission Minor Rebuild

36/6

Transmission Minor Rebuild

37/7

Transmission Minor Rebuild

38/1

Transmission Minor Rebuild

42/8

Transmission Minor Rebuild

43/5

Transmission Minor Rebuild

50/7

Transmission Minor Rebuild

66/4

Transmission Minor Rebuild

R-44768
EXHIBIT B RATE SHEET -- ALTERNATE BID
Metro - Sunset 115 kV Transmission Line Rebuild

Alterations to the Bid Sheet by Contractor are not allowed. All quantities included in this Bid Sheet are estimated and these units may vary. All pricing excludes sales tax.
The Contract will not be considered complete and a 5% retention of the total Contract price will be withheld until all clean-up has been completed and accepted by Avista's Representative on the job and all damage claims have been satisfied, if applicable.

Task #	Task Description	Unit of Measure	Est # of Units	Unit Price	Total Price
Task 1	Mobilization and De-mobilization (1)	Lump Sum	1	$ 55,000.00	$55,000.00
Task 2	Provide Temporary Access and Road Work	Lump Sum	1	$ 13,500.00	$13,500.00
Task 3	Excavate Pole Foundations				
a.	New Hole-In Soil or Loose Rock (Augered)	Lin Ft.	140	$ 2,100.00	$294,000.00
b.	New Hole-In Solid Rock (Augered)	Lin Ft.	50	$ 3,000.00	$150,000.00
c.	New Hole (Hand Digging)	Lin Ft.	0	$ 3,300.00	$0.00
Task 4	Install Anchors				
a.	Crossplate Anchors	Each	4	$ 5,200.00	$20,800.00
b.	Rock Anchors	Each	4	$ 2,500.00	$10,000.00
Task 5	Install Guys	Each	8	$ 550.00	$4,400.00
Task 6	Furnish and Place Backfill				
a.	Select Aggregate Backfill (2)	Ton	80	$ 55.00	$4,400.00
b.	Controlled Density Fill (CDF) (2)	Cu Yds	15	$ 165.00	$2,475.00
Task 7	Install New Transmission Structures				
a.	SW	Each	2	$ 12,500.00	$25,000.00
b.	SW1	Each	6	$ 12,500.00	$75,000.00
c.	RPDE-O	Each	1	$ 17,500.00	$17,500.00
d.	Helicopter 2/4, SW1	Each	1	$ 29,900.00	$29,900.00
e.	Helicopter 2/5, SW	Each	1	$ 29,900.00	$29,900.00
f.	Helicopter 2/6, SW	Each	1	$ 29,900.00	$29,900.00
Task 8	Transmission Conductor	Circuit Mile	2.5	$125,250.00	$313,125.00
Task 9	Remove Existing Transmission Conductor	Circuit Mile	2.5	$ 55,000.00	$137,500.00
Task 10	Remove Existing Structures, Anchors, and Hardware	Each	12	$ 8,500.00	$102,000.00
Task 11	Top Existing Transmission Structure	Each	2	$ 1,200.00	$2,400.00
Task 12	Optical Ground Wire (OPGW) Installation(3)	Miles	2.5	$ 60,250.00	$150,625.00
Task 13	Test and Splice Optical Ground Wire (OPGW)	EA	2	$ 4,000.00	$8,000.00
	Part B - Distribution Work				
Task 14	Install New Distribution Crossarms and Associated Hardware	Each	3	$ 850.00	$2,550.00
Task 15	Transfer Existing Distribution Underbuild	Each	2	$ 1,500.00	$3,000.00
Task 16	String and Sag New Distribution Conductor				

BidSheet Page 1 of 6

Transmission Minor Rebuild

R-44768
EXHIBIT B RATE SHEET -- ALTERNATE BID
Metro - Sunset 115 kV Transmission Line Rebuild

Alterations to the Bid Sheet by Contractor are not allowed. All quantities included in this Bid Sheet are estimated and these units may vary. All pricing excludes sales tax.

The Contract will not be considered complete and a 5% retention of the total Contract price will be withheld until all clean-up has been completed and accepted by Avista's Representative on the job and all damage claims have been satisfied, if applicable.

Task #	Task Description	Unit of Measure	Est # of Units	Unit Price	Total Price
	Replace Neutral with 556 AAC "Dahlia"	Circuit Mile	0.2	$ 15,840.00	$3,168.00
Task 17	Remove Existing Distribution Conductor Neutral	Circuit Mile	0.2	$ 5,280.00	$1,056.00
Task 18	Site Clean Up and Restoration	Lump Sum	1	$ 12,500.00	$12,500.00
				TOTAL	$1,497,699.00

(1) Mobilization / Demobilization shall not exceed 10% of Total Price

(2) This is a neat line calculation with a 10% adder.

(3) The scope of the OPGW stringing is still under review.

Any

Labor Rates for change orders will use Labor Rates provided at the time of Contract Execution

Any additional materials will be billed at cost plus 5%

Rental of special construction equipment requested by Avista shall be billed at cost plus 5%

Rental of standard construction equipment not shown in your RFP package shall be billed at cost.

Rev 3-1-2016

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Ken Sweigart	BC Owner	APPROVED By Ken Sweigart at 9:07 am, Oct 10, 2023	10-10-2023
	BC Sponsor	Vern Malensky	10.11.2023
	Steering Committee (If applicable)		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Transmission Construction Compliance

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Transmission Construction – Compliance Business Case covers the Transmission rebuild and reconductor work necessary to maintain compliance with the NERC Reliability Standard TPL-001-4 – Transmission System Planning Performance Requirements ("Standard"). This standard mandates that an annual planning assessment be conducted and corrective actions be identified and implemented to remedy any system performance deficiencies.

The Transmission Construction – Compliance Business Case also covers the Transmission line rebuild for lines not meeting National Electric Safety Code (NESC) physical capacities for appropriate loading cases. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC). These lines may have met the NESC criteria at the time of their original construction, but have been found to not be up to standards through analysis either as a result of requests for facility additions, or identified past additions not analyzed at the time of installation.

Transfer to Plant Variance (over) was likely due to the Budgeted Transfer to Plant (TTP) Plan varying from the 2023 budget for this Business Case. The TTP Plan was $1,550,000, whereas the Budget was $2,000,000. The budget amount more closely matches the Actual TTP Gross Plant amount of $2,087,169. The increase in budget to $2,000,000 for 2023 was due to inflationary pressure and to accommodate ancillary line upgrade work on the BLD-IRV#1, requested to meet emerging TPL-001-4 Study Cases. The 2024 budget will reflect a similar ancillary project on this same line to complete the required ratings upgrade work.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

No cost overruns were associated with this Business Case (project) for 2023. However, this Business Case is monitored through the year and reviewed at the Electrical Engineering Budget Committee each month. If a cost overrun were to occur, a discussion and decision would direct the appropriate path forward.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There is no change in Offsets.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

x **APPROVED** *By Ken Sweigart at 1:20 pm, Feb 21, 2024*

DIRECTOR SIGNATURE:

x

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Transmission Major Rebuild Asset Condition

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Transmission Major Rebuild – Asset Condition Business Case covers major rebuilds of transmission lines due to overall asset condition. Although line conductor will sometimes be included in the rebuild scope, the primary target of this business case is the replacement of aging wood infrastructure. Factors considered in prioritizing work include condition, sustained outages, accessibility, system reliability, wildfire risk, customer density, and reputation impact. Potential for joint facility improvements (i.e. communications build-out) are also considered in prioritizing this work. The projects within this program are developed through Asset Management's general analysis of Avista's Transmission System facilities that provides a risk-based ranking of over 100 Transmission Lines. Projects are chosen to maximize stakeholder value.

Transmission outages can have significant consequences, as they tend to impact a large number of customers and have the potential to start fires in dry areas. In addition to reliability issues, failure to properly invest builds a bow-wave of needed investments in the future, thus this program is crucial to maintaining operations. When facilities reach an age when it is close to or at the end of its useful life, the Company preventively replaces it to maintain reliability and acceptable levels of service.

Transfer to Plant Variance (over) was due to a transition from projects that build over the Winter encompassing two Fiscal Years to projects that build within one Fiscal Year. For 2023 this meant that the HAT-M23 230kV project completed (TTP'd) in the Spring and the 1st Phase of the PIP-RAT 115kV project completed in the Fall. Variance is due to timing.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

No cost overruns were associated with this Business Case (project) for 2023. However, this Business Case is monitored through the year and reviewed at the Electrical Engineering Budget Committee each month. If a cost overrun were to occur, a discussion and decision would direct the appropriate path forward.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There is no change in Offsets.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

x **APPROVED**
By Ken Sweigart at 1:25 pm, Feb 21, 2024

DIRECTOR SIGNATURE:

x [signature]

Transmission Major Rebuild – Asset Condition

1.0 CHANGE REQUEST #01 – OCTOBER 2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
10-10-2023	*Scope Change*	01	$10,250,000	-$1,500,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
10-10-2023	Scope Change			$10,250,000	$8,750,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This should not be considered approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Transmission Major Rebuild – Asset Condition

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

This release breaks down into two areas of the Transmission Major Rebuild – Asset Condition BC:

- HAT-M23 230kV Rebuild: This project completed in the earlier part of 2023 and came in under budget.
- PIP-RAT 115kV Rebuild: The project Scope was reduced due to Real Estate/Outage issues around the Spirit Lake Tap (this work was rescheduled for 2024).

The entirety of this release will partially balance the request associated with the Transmission Minor Rebuild BC ($2.25M)

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Ken Sweigart	BC Owner	APPROVED By Ken Sweigart at 12:41 pm, Oct 10, 2023	10-10-2023
	BC Sponsor	Vern Malensky	10.11.2023
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Transmission NERC LPRM

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Transmission NERC Low Priority Lines Mitigation Business Case covers the work to reconfigure insulator attachments, and/or rebuild existing transmission line structures, or remove earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012 North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program covers mitigation work on Avista's "Low Priority" 230kV and 115kV transmission lines. Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have also been adopted into the State of Washington's Administrative Code (WAC). This program is expected to be completed in 2024.
Transfer to Plant Variance (under) was due to the Project Number staying open into 2024 to complete a handful of structures left unfinished in 2023. The carry-over of this work was due to a Transformer failure requiring work to be completed "hot". Dead-end structures are not worked on under "hot" conditions and therefore had to wait until the Transformer was back in service.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

No cost overruns were associated with this Business Case (project) for 2023. However, this Business Case is monitored through the year and reviewed at the Electrical Engineering Budget Committee each month. If a cost overrun were to occur, a discussion and decision would direct the appropriate path forward.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

There is no change in Offsets.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

x **APPROVED** By Ken Sweigart at 1:23 pm, Feb 21, 2024

DIRECTOR SIGNATURE:

x

Transmission NERC Low-Risk Lines Mitigation

1.0 CHANGE REQUEST #01 – OCTOBER 2023

For new change requests, update the Change Request # and Date.

Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
10-10-2023	*Scope Change*	01	$2,500,000	-$500,000		
	Choose an item.					
	Choose an item.					

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
10-10-2023	Scope Change			$2,500,000	$2,000,000
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This should not be considered approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Transmission NERC Low-Risk Lines Mitigation

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

This release breaks down into one area of the Transmission Low Priority Ratings Mitigation BC:

- 9CE-3HT (Latah Tap) 115kV Line: This project will now complete in 2024 due to Benewah Transformer outage restrictions on 2023 work, reducing 2023 scope.

The entirety of this release will partially balance the request associated with the Transmission Minor Rebuild BC ($2.25M)

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature	Date
Ken Sweigart	BC Owner	APPROVED By Ken Sweigart at 12:44 pm, Oct 10, 2023	10-10-2023
	BC Sponsor	Vern Malensky	10.11.2023
	Steering Committee (If applicable)		

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Electric Transportation (Washington)

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5-year planning cycle)?

☒ Yes ☐ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The Electric Transportation business case supports beneficial electrification in alignment with the Company's comprehensive Transportation Electrification Plan and accompanying programs authorized by tariff schedule 077. In 2023, transfer to plant was estimated at $3,900,000 compared to an actual of $1,523,470, resulting in a variance of $2,376,530 less than estimated.

The variance is due to a lower number of charging station installations than projected in the original TE Plan and business case. Commercial AC Level 2 installations were lower than expected, most likely due to lower spending on education and outreach activities to inform customers of available programs. For DC fast charging stations, negotiations with property owners to obtain legal site agreement contracts and property easements have proven more difficult than expected, for many locations. Finally, an anticipated federal grant was delayed, which reduced the need to purchase equipment as originally expected.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Although the leadtimes and cost of materials, as well as the cost of labor has increased in recent years due to broad inflation, project costs are as planned and remain satisfactory. Project management is tightly managed by experienced staff, with oversight provided by a sponsor committee. Costs and overall program effectiveness and results are also monitored via detailed annual reports provided to the UTC.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

No direct offsets are associated with this business case. Indirect benefits include revenue growth associated with electric transportation charging loads, lower transportation costs and reduced emissions and air pollution from the transportation sector which benefit the general public, and are aligned with Washington State policy goals.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X

RENDALL FARLEY
2/22/2024

DIRECTOR SIGNATURE:

X Nicole L. Hydzik

Digitally signed by Nicole L. Hydzik
Date: 2024.02.21 12:52:24 -08'00'

Transportation Electrification - Washington

EXECUTIVE SUMMARY

Transportation electrification represents an historic, strategic opportunity – in many ways it is one of the keys to the future of the Company, providing transformational economic and environmental benefits for customers over the next several decades. Avista's Transportation Electrification Plan (TEP) was filed with the Washington UTC on July 1, 2020, providing guiding principles, budgets and cost/benefit analysis through 2030, and a comprehensive plan of supporting activities focused on the 2021-2025 timeframe. Following this, the UTC acknowledged the TEP in October 2020, followed by authorizing tariffs 077, 013 and 023 going into effect April 26, 2021. The TEP and respective tariffs cement the utility role in supporting electric transportation for the long-term, aligned with strong legislative support as codified in RCW 80.28.360 and 80.28.365, the UTC Policy Statement in Docket UE-160799, and state policy goals such as 100% EV sales by 2035.

The TEP builds upon the lessons learned from the Electric Vehicle Supply Equipment (EVSE) pilot of 2016-2019, which demonstrated the tremendous benefits of electric transportation and the essential role of the utility to benefit all utility customers, as transportation loads are estimated to account for 20% or more of overall electric load by 2050. Investments and activities will take the form of charging infrastructure buildout and maintenance, research and support of emerging commercial, medium and heavy-duty applications, transportation rate design, education and outreach, community and low-income support programs, grid integration, and internal programs such as utility fleet electrification, facility charging infrastructure, and employee engagement. Utility initiatives and programs to support and accelerate transportation electrification are aligned with Washington State's public policy and goals, recognizing that transportation accounts for nearly 50% of greenhouse gas emissions and air pollution.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Rendall Farley*	*Initial draft of original business case*	*7/11/2019*
2.0	*Rendall Farley*	*2020 update following TEP filing with the UTC*	*7/10/2020*
2.1	*Rendall Farley*	*2022 update*	*9/9/2022*
2.3	*Rendall Farley*	*2023 update*	*4/27/2023*
BCRT	*BCRT Team Memember* Christine Tasche	*Has been reviewed by BCRT and meets necessary requirements*	5/04/23

Transportation Electrification - Washington

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$4,163,719**	**$3,620,625**
2025	**$4,788,277**	**$4,163,719**
2026	**$5,506,518**	**$4,788,277**
2027	**$6,332,496**	**$5,506,518**
2028	**$6,332,496**	**$6,332,496**

Project Life Span	*5 years*
Requesting Organization/Department	Electric Transportation / Energy Efficiency
Business Case Owner | Sponsor	Rendall Farley | Nicole Hydzik | Kevin Christie
Sponsor Organization/Department	Customer Solutions
Phase	Monitor/Control
Category	Program
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Transportation Electrification - Washington

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

1.1 What is the current or potential problem that is being addressed?

Transportation electrification is a key long-term strategy to significantly reduce emissions and reduce transportation costs for customers, while providing beneficial utility load growth. If managed well, this could result in downward rate pressure while offering substantial utility revenue and earnings potential over the long-term. The business opportunity addressed by the TEP is to support and accelerate a beneficial and sustainable transition to electric transportation, providing significant benefits and choices for customers to move people and goods using electricity as a clean, reliable and more affordable transportation fuel. Additionally, and of critical importance, is the TEP's role in ensuring that this transition happens in a way that is optimally integrated with the grid. Short-term objectives are to experiment and learn, strengthen customer relationships, and align with policymakers and regulators. Long-term objectives are to play a key role in fundamentally transforming the transportation sector, achieving major customer and societal benefits on the order of over $1 billion saved per year in "fueling" costs in the regional economy by 2050, while eliminating 80% or more of harmful emissions and pollution from transportation, and grid integration that results in beneficial utility revenue that will grow significantly over time. By 2030, this may be on the order of over $12 million per year in utility revenue– representing just the beginning as market segments accelerate and expand beyond this point in the next several decades.

1.2 Discuss the major drivers of the business case.

The primary drivers are related to long-term business growth, grid reliability through load management and prudent asset management, low income and named community support in alignment with our Clean Energy Implementation Plan (CEIP), and increased customer satisfaction. Customer benefits include fuel and maintenance savings, reduced emissions and pollution, and decreased rate pressure from beneficial electric load growth over the long-term, that better utilizes grid assets.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The TEP follows from the EVSE pilot concluded in 2019, keeping pace with industry and market developments/opportunities. Delays or deferment will risk adequate investments and learning necessary to achieve strategic objectives, as detailed in the TEP. Reputational risk with regulators and stakeholders is also an important consideration as the CEIP and rate case settlements have TE related commitments.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Our Vision – Better Energy for Life, is realized through our Mission – to improve customers' lives through innovative energy solutions. The strategic vision of Avista' TE Plan is in full alignment, supporting long-term, overarching goals.

Over the course of the next several decades, an amazing transformation will occur – the transportation sector will converge with the energy and information technology sectors, fundamentally changing the way we live and making the world a better place. Avista will play a key role in this transformation, working over several decades with industry partners, policymakers and regulators, community leaders, and customers to innovate and create a better energy future for all.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Please see the TE Plan and the 2022 Annual TE Report, available at www.myavista.com/transportation. Avista successfully expanded TE programs and activities in 2022, consistent with the TE Plan and tariff schedule 077. The table below summarizes key results for the calendar year ending December 31, 2022:

3,314	Number of light-duty passenger and truck EVs registered in Avista's service territory in Washington State, as of December 31, 2022
$4.2 million	Regional transportation cost savings
11,348	Avoided tons of CO_2 emissions
7,872	MWh charging consumption
1.9	MW charging peak load
$791,828	Revenue from light-duty EV charging
$2,235,866	TE Capital investments
$555,089	TE Operating expenses
481	Residential AC Level 2 (ACL2) ports in service
428	Commercial ACL2 ports in service
16	DC Fast Charging (DCFC) ports in service
96%	ACL2 equipment uptime
89%	DCFC equipment uptime
98%	Customer satisfaction with Avista TE programs
25	Electric forklift incentives
5	Fleet consultation services
32,080	Customer web page visits
7	Active number of Community-Based Organization (CBO) partners
21,961	Travel services provided by CBO partners (passenger-miles)
105	Charging ports in Named Communities and CBOs
42	Community and stakeholder education and outreach engagements

Table 1: 2022 TE Results

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

A moderate growth strategy is recommended, investing $27 million of capital from 2024 through 2027. This is the most appropriate strategy at the current time given the early market phase of light-duty EV adoption and other forms of electric transporation both on-road and off-road. A more aggressive strategy may be more appropriate for some period of time in the future as the market transitions to an accelerated trajectory and the impacts to the grid and society as a whole are more certain, and in consideration of the strong policy support at both the state and federal levels. This will continue to be driven by compelling ongoing concerns of climate risks posed by greenhouse gas emissions in general and the fact that transportation accounts for the largest share of emissions of any sector in the economy. In addition, the tremendous benefits for the regional economy as well as for the grid and the utility will be compelling factors potentially justifying a more aggressive strategy at some point in the future.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Considerable research and analysis were considered in the preparation of the TEP, annual reports and adjustments to plan. Please see the economic and grid impact modeling, and cost and benefit sections of the TEP for details, as well as annual reports. Excerpts include the following:

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

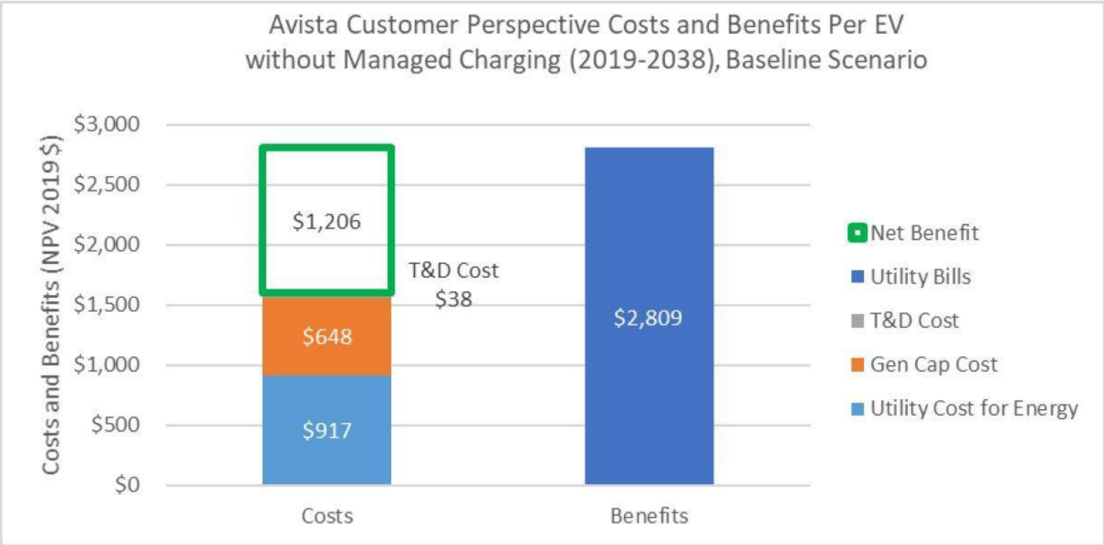


Figure 21: Utility customer perspective costs and benefits per EV without managed charging 2019-2038

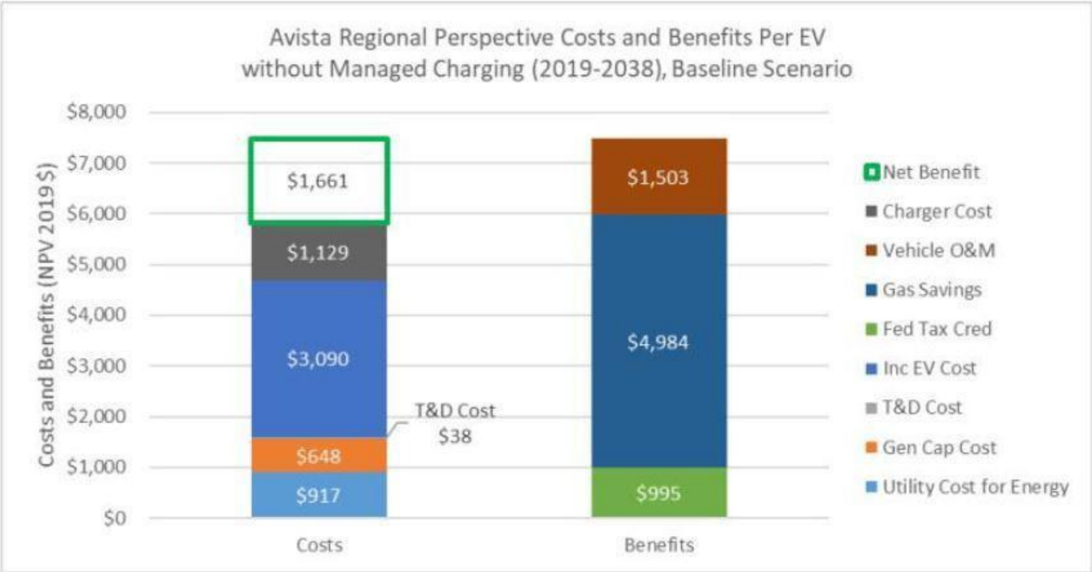


Figure 20: Regional perspective costs and benefits per EV without managed charging 2019-2038

Transportation Electrification - Washington

Table 8: High EV adoption— annual costs and benefits for Avista Washington customers

Year	# EVs (WA)	Utility Billing Revenue	kWh	Coinci-dent kW (January 6pm)	Utility Generation and Delivery Cost	Net Revenue Offsetting Benefit	Avoided CO_2 Emis-sions (Tons)	Customer Transporta-tion Fuel and Maintenance Savings
2021	1,678	$510,178	5,291,422	1,309	$104,097	$406,081	6,713	$2,488,798
2022	2,311	$702,678	7,287,975	1,803	$145,615	$557,063	9,246	$3,427,868
2023	3,115	$946,884	9,820,809	2,430	$200,738	$746,146	12,459	$4,619,175
2024	4,262	$1,295,610	13,437,696	3,324	$290,353	$1,005,257	17,048	$6,320,363
2025	5,958	$1,811,376	18,787,072	4,648	$427,589	$1,383,788	23,834	$8,836,419
2026	8,468	$2,574,194	26,698,798	6,605	$1,359,597	$1,214,597	33,871	$12,557,665
2027	12,179	$3,702,402	38,400,242	9,500	$1,948,744	$1,753,658	48,716	$18,061,389
2028	17,857	$5,428,560	56,303,451	13,929	$2,969,483	$2,459,077	71,428	$26,482,086
2029	26,545	$8,069,581	83,695,360	20,705	$4,535,926	$3,533,655	106,179	$39,365,753
2030	40,454	$12,298,165	127,553,008	31,555	$7,087,290	$5,210,875	161,818	$59,994,009

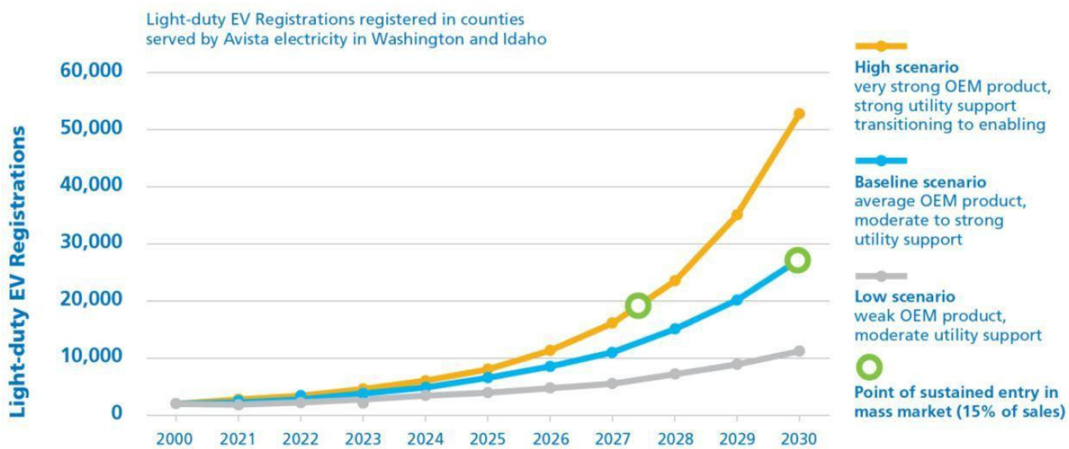


Figure 4: Light duty EV adoption forecasts for registered light-duty vehicles in Avista's service territory; sources include Washington and Idaho registration data; Bloomberg New Energy Finance Electric Vehicle Outlook, 2019; "Economic & Grid Impacts of Electric Vehicle Adoption in Washington & Oregon." Energy and Environmental Economics (2017).

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

TE capital investments are investments in beneficial load growth, which result in regional economic and environmental benefits, as well as downward rate pressure over the long term due to increased net revenue. As such, they do not result in direct or cost offsets or savings in Capital or O&M as described in the definitions below.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

TE capital investments are investments in beneficial load growth, which result in regional economic and environmental benefits, as well as downward rate pressure over the long term due to increased net revenue. As such, they do not result in indirect cost offsets or savings in Capital or O&M as described in the definitions below.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

High growth strategy ($35M) – state of the market transition still too early to justify this more aggressive strategy. Adoption trajectories show an early transition to the predicted high adoption scenario anticipated to start in 2023. However, there remains some uncertainty as to when the market will transition to a more exponential and sustained growth trajectory, that would justify a more aggressive, higher growth strategy that was considered. This may be a prudent approach at some point in the future but is not recommended at the current time.

Alternative 2:

Low growth support strategy ($12M) – clearly underfunds capital investments necessary to support early market growth and prepare the utility for future, significant TE loads. This approach would not provide an adequate foundation of charging infrastructure to enable existing moderate growth and set the stage for accelerated future growth, as well as support for expansion in commercial fleets, load management capability development, and community and low-income support expected by regulators and stakeholders.

Alternative 3:

Do nothing ($0) – A do-nothing approach is not recommended as it would completely fail to capitalize on compelling business opportunities to better serve our customers and communities as well as irresponsibly ignore planning for grid impacts and integration required to meet growing TE loads in the future.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

A number of metrics are utilized to monitor and report on TE activities, both leading and lagging indicators of success, as summarized in Table 1 of the annual TE report. Programs and results will be continuously monitored and improved upon by dedicated staff, utilizing a number of performance metrics as listed above, including adoption updates, detailed cost analysis, equipment reliability, and customer satisfaction.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Capital investments began in Q2 2021 and are proceeding according to the TE Plan, continuously through 2027 and beyond.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Daily oversight and governance is carried out by the responsible program managers up through the Director of Energy Efficiency and Chief Customer Officer and Vice President of Regulatory Affairs. Regular meetings are held with advisory and executive sponsor steering groups including leaders of Customer Solutions, External Affairs, Energy Delivery, Energy Resources, and Government Relations. These meetings involve a variety of discussions including status updates and guidance for ongoing program direction and adaptive management, including key strategic decisions and direction. Quarterly meetings update progress with the Washington State Joint Transportation Electrification Stakeholder Group, and detailed annual reports are submitted as well.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the business case for *Transportation Electrification – Washington,* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Rendall Farley	Date:	4/27/2023
Print Name:	Rendall Farley		
Title:	Manager of Electric Transportation		
Role:	Business Case Owner		
Signature:	Nicole L. Hydzik	Date:	4/27/2023
Print Name:	Nicole Hydzik		
Title:	Director of Energy Efficiency		
Role:	Business Case Sponsor		
Signature:		Date:	4/27/2023
Print Name:	Kevin Christie		
Title:	Senior VP, External Affairs and Chief Customer Officer		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

CAPITAL ADDITIONS VARIANCE EXPLANATION FORM

BUSINESS CASE NAME:

Upper Falls Trash Rake Replacement

FOR THE CURRENT REPORTING PERIOD (JAN – DEC 2023), HAS YOUR BUSINESS CASE JUSTIFICATION CHANGED SINCE FILED (on record with FP&A as of Sept 2021 for the 2022-2027 5 year planning cycle)?

☐ Yes ☒ No If yes, please attach revised business case.

PLEASE EXPLAIN THE TRANSFER TO PLANT VARIANCE OF GREATER THAN $500,000 AND +/-10% FOR THE CURRENT REPORTING PERIOD:

The original approved budget for this project was determined based on the Nine Mile Trash Rake Replacement which occurred in 2018. The original estimate did not account for project details and was insufficient based on real costs. Efforts were made throughout the project life cycle to keep costs low including competitive bidding for all major services, the selection of the lowest cost vendor for each service, and managing change requests to reduce cost overruns due to scope creep. design, construction, major equipment, inspection services, and early contractor procurement. Two funds change requests (FCRs) were submitted for this project. The initial FCR was submitted upon receiving cost estimates from vendors for the design and construction of the project. The lowest cost vendors were selected throughout the contractor selection process, as documented in the attached FCR #1. The second FCR was made upon finalizing all project scope elements, which led to additional vendor and labor costs, as documented in the attached FCR #2.

EVIDENCE THAT ANY SIGNIFICANT COST OVERRUNS AND THE DECISION TO CONTINUE TO INVEST IN THE PROJECT WAS PRUDENT for example, stakeholder meeting approval, CPG funds change requests (please attach supporting documentation):

Two funds change requests (FCRs) were submitted for this project. The initial FCR was submitted upon receiving cost estimates from vendors for the equipment, design, construction of the project. The lowest cost vendors were selected throughout the contractor selection process, as documented in the attached FCR #1. The second FCR was made upon finalizing all project scope elements, which led to additional vendor and labor costs, as documented in the attached FCR #2. The project change log is also attached to demonstrate that changes were reviewed and approved throughout the project.

ARE THERE REVISED OFFSETS ASSOCIATED WITH THIS CHANGE IN PLANT ADDITIONS? Please explain.

Indirect offsets are associated with this project, including increases in machine efficiency that will result in lowered maintenance costs and increased system function such that trash rake operation requires less personnel.

I have reviewed the information contained in this response for this specific business case, and to the best of my knowledge the information is true, correct, and comprehensive.

BUSINESS CASE OWNER SIGNATURE:

X Michael Truex
Michael Truex (Feb 29, 2024 08:51 PST)

Michael Truex
Michael Truex (Feb 29, 2024 08:51 PST)

DIRECTOR SIGNATURE:

X David Howell
David Howell (Feb 29, 2024 08:56 PST)

Upper Falls Trash Rake Replacement

1.0 CHANGE REQUEST #1

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
08/09/2023	*Revised Cost*	1	$1.2M	$640k		$1.84M
	Choose an item.					
	Choose an item.					

* See note in description for details on the revised budget amount

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
08/09/2023	Revised Cost	N/A	N/A	$2.34M	$2.34M
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This should not be considered approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

Upper Falls Trash Rake Replacement

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The original approved budget for this project was determined based on the Nine Mile Trash Rake Replacement which occurred in 2018. The original estimate did not account for project details and is insufficient based on real costs. This request is being made upon receiving cost estimates from all vendors required for the project. The project team has worked to limit project expenses as evidenced by the team's decisions throughout the project, catalogued below.

After extensive vetting, the project team selected Enerquip as the trash rake supplier over Kuenz because of their lower cost and higher functionality ($617,170 for an Enerquip machine vs. $641,680 for a Kuenz machine). In selecting a design contractor, the project team evaluated three firms, Coffman ($143,065), KPFF ($324,390), and TD&H Engineering ($229,315). Coffman was selected for their ability to provide design and engineering services and were the lowest bid of the firms evaluated. To secure the long lead items necessary for the construction effort, Avista engaged Lydig for pre-construction services that included material procurement and fabrication. Lydig ($155,700) was selected as they were the most qualified to perform the work and were less than $10k more expensive than the lowest bid received (Knight, $146,431). Knight was then selected as the construction contractor due to their qualifications as well as for their competitive pricing. Compared to the bids received from Lydig at $882k and Kuney at $1.3M, Knight was the lowest bid at $664,681.

While there have been several minor change orders (all under $10k) that have impacted cost, the most significant unplanned cost relates to a schedule delay realized in the project's procurement timeline. A delay in procurement of steel components extended the overall construction schedule by two weeks. This delay added additional costs to our construction and inspection services, including a change order of $53k on Knight's construction contract. A small contingency ($50k) was also added to the construction cost to account for any additional future changes to ensure this funding request is comprehensive of all project work. The reason for the revision from the original request in the beginning of August and the request now at the end of August, is that these changes were all realized in this time period. Since the beginning of August the project has incurred $53k in additional charges related to delay, an estimated $30k in change orders, and an addition of a $50k contingency to account for future changes, amounting to a need for $130k additional dollars from the original request.

Combined, project costs plus Avista overheads and labor result in a total expected spend of $2.34M as shown in the summary table, below. The project team has continually evaluated firms for their ability to achieve the quality of work needed, as well as for their overall cost. Despite selecting the lowest cost vendors, cost overruns are still anticipated. The originally approved and forecasted total did not account for actual costs. With minor change orders and the schedule delay, the table below reflects the most accurate estimate to complete work.

Summary of Project Costs (Lifetime)

Labor	$163,588
Design & Inspection	206,254
Construction	756,245
Travel & Employee Expenses	21,833
Materials & Equipment	31,281
Large Materials + Shipping	883,685
Stores/Material Loadings	14,604
Capital OH	158,791
AFUDC	66,987
Taxes	40,967
Total	**$2,344,234**

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

** Please note that the project is requesting $510k for expenses in 2023, which will bring the total approved budget in 2023 from $1.2M to $1.84M. However, $200k in charges were realized in December of 2022 which caused the project to exceed approved spend in 2022 by that amount. Given this $200k overage, the total expected spend for the project is $2.34M.*

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature
PJ Henscheid	BC Owner	
Alexis Alexander	BC Sponsor	
	Steering Committee (If applicable)	

1.0 CHANGE REQUEST #2

For new change requests, update the Change Request # and Date.
Add a new line to the top of the table to log current requests, keep previous requests below to log over the life of the business case.

Request Date	Request Type	Request Number	Approved Budget	Requested Change	Change Amount Approved by CPG	Revised Budget Amount
08/09/2023	*Revised Cost*	1	$1.2M	$640k	$640k	$1.84M
11/2023	*Revised Cost*	2	$1.84M	$154k		$1,994,000

* See note in description for details on the revised budget amount

Complete the following for the current request

CURRENT YEAR REQUESTS

	Offsets Impact			TTP Impact	
Request Date	Request Type	Budgeted Savings /Offsets[1]	Revised Savings /Offsets	Currently Planned TTP[2]	Revised TTP
11/2023	Revised Cost	N/A	N/A	$2.2M	$2.2M
	Choose an item.				
	Choose an item.				

PROJECTED CHANGE TO FUTURE YEAR REQUESTS

(To be completed for impacts of in year requests or 5 year funding requests. Identify which in the log above. This **should not be considered** approval for future year funding. Future funding changes will need to be submitted through the 5 year planning process.)

	Funding Impact		Offsets Impact		TTP Impact	
Year	Budgeted Approved Amount[3]	Updated Funding Anticipated as a result of request	Budgeted Benefits /Offsets[4]	Revised Benefits /Offsets	Budgeted TTP[5]	Revised TTP
2024						
2025						
2026						
2027						
2028						

[1] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[2] The information for the current year should be obtained from the *General Information* section of the Business Case.
[3] The information for the current year should be obtained from the *General Information* section of the Business Case.
[4] The information for the current year should be obtained from sections 2.3 or 2.4 of the Business Case.
[5] The information for the current year should be obtained from the *General Information* section of the Business Case.

THIS SECTION MUST THOROUGHLY DESCRIBE THE REASON FOR THE FUNDS CHANGE REQUEST INCLUDING WHAT ALTERNATIVES WERE CONSIDERED. [6]

The original approved budget for this project was determined based on the Nine Mile Trash Rake Replacement which occurred in 2018. The original estimate did not account for project details and was insufficient based on real costs. The initial funds change request (FCR) was submitted upon receiving cost estimates from all vendors required for the project. In the original FCR, the project team demonstrated how the lowest-cost vendor was selected at each decision point. This new request is being made upon finalizing all project scope elements, which led to additional vendor and labor costs.

Due to $80k in added labor charges, project change orders amounting to $50k, and additional taxes and overheads amounting to $24k, the project requires $154k in additional dollars to close. Our EAC for all years is now forecast at $2,494,000, with the EAC for 2023 forecast at $1,994,000. The additional labor was needed to meet the outage schedule and to accommodate the 12-hour installation schedule recommended by the trash rake manufacturer and includes overtime by our union and operators. Change orders include the labor and materials necessary to conduct platform repairs that were required to ensure the longevity of the new machine. They also include the labor and materials necessary to reconcile drawing discrepancies that were identified upon installation. The taxes and overheads are a result of added labor costs and as the result of change orders increasing our overall spend.

The investment remains prudent for our organization, as this increase in approved spend will allow us to fulfill our contractual obligations and formally close the project.

2.0 CHANGE REQUEST APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the funds change request and agree with the approach it presents, and that it has been approved by the relevant governance group. Signatures are required before changes can be considered.

Name	Role	Signature
PJ Henscheid	BC Owner	
Alexis Alexander	BC Sponsor	
	Steering Committee (If applicable)	

[6] I.E., scope change, schedule changes, additional risks, newly discovered items, customer requests, etc.

Project Name: Upper Falls Trash Rake
Project #: 20405041

UF Trash Rake - PROJECT CHANGE LOG

Contract # & Description	Vendor	Value	CO's	Contingency	Contract Type
R-43400 WA No. 13 Construction Services	Knight	$ 664,681.00	$113,452.00	$ -	Lump Sum
			-		
			-		
			-		
			-		
			-		

DC	Document Correction/Design Change
UC	Unforseen Condition
OB	Owner Betterment
PA	Project Accounting
RR	Risk Registry/Contingency
PR	Permitting/Compliance
CPG	Capital Planning Group

All CO's are saved to the project files here: rp-my.sharepoint.com/:f:/p/allyson_tanzer/Es3fx0nZfKFPmQpgwnw65OQBQ17_I_ONeeCUIzqavI

Change #	Description of Change	Initiated by/ Requestor	Date Submitted	Date Approved	PCR #	Approver	Cost Estimate / Actual	Type	Schedule Impact '+/- Days	Status	Contract Type	Comments
0	Addition of pre-construction services to project scope to account for all steel fabrication. Because of extensive lead times associated with this work, Avista elected to engage Lydig for pre-construction services.	Avista	NA	NA	NA	Alexis Alexander	$155,700.00	UC	0	Approved	Lump Sum	No associated CO, resulted in additional WA for Lydig
1	Upon demo, existing conditions were revealed that required repair. Repairs include rust cleaning and painting of existing beams and repairs to concrete stairs	Avista	08/01/23	08/01/23	001	Alexis Alexander	$9,698	UC	0	Approved	Lump Sum	
2	Additional labor and equipment costs incurred due to two-week procurement delay on structural steel and managing drawing inconsistencies	Avista	08/14/23	09/06/23	002	Alexis Alexander	$ 58,579.00	UC + DC	14 DAYS	Approved	Lump Sum	
3	Environmental team requested alternate method of concrete curing to eliminate river discharge which resulted in added Labor costs for this work	Avista	09/26/23	10/04/23	003	Alexis Alexander	$ 6,084.00	OB	0	Approved	Lump Sum	
4	Additional labor and equipment costs to address drawing discrepancies and miscellaneous owner requests throughout project duration	Avista	10/31/23	10/31/23	004	Scott Kinney	$ 39,091.00	OB	0	Approved	Lump Sum	
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AVISTA

Project Change Request (PCR)

Project Name:		PCR #:	
Business Case:		Date:	
Project #:		Task #:	
Contract #:		Requestor:	
Owner:	Avista Utilities 1411 E. Mission Spokane, WA 99202	Contractor/Consultant:	

In order to expedite the work and avoid or minimize delays in the work, which may affect contract sum or contract time, the contract documents are hereby amended as described below.

Reason for Change:

☐	DC	Document Correction/Design Change	☐	RR	Risk Registry/Contingency
☐	UC	Unforseen Condition	☐	PR	Permitting/Compliance
☐	OB	Owner Betterment	☐	CPG	Capital Planning Group
☐	PA	Project Accounting			

Description:

Notes:

Attachments: None

Change Cost Estimate/Actual: ______ including Tax ☐ Lump Sum ☐ T&M NTE

Schedule Impact: ______ Days

Previous Contract Date: ______ New Contract Date: ______

*Project Change Requests are not authorized until all signatures are obtained.

Change Approval Thresholds:

Manager/Budget Owner	$25,000 or less	Bruce Howard
Director/Steering Committee	$25,000 - $99,999	Bruce Howard
Vice President	$100,000 - $499,999	
Sr. VP/CFO	$500,000 - $2,999,999	Latisha Hill
President	$3,000,000 and above	Dennis Vermillion

Project Change Request (PCR)

Project Name:	0	PCR #:	0
Business Case:	0	Date:	1/0/00
Project #:	0	Task #:	0
Contract #:	0	Requestor:	0

Approval Signatures:

	10/2/2020
Allyson Tanzer - Project Manager	Date