Exh. HLR-2

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-22_____

DOCKET NO. UG-22_____

EXH. HLR-2

HEATHER L. ROSENTRATER

REPRESENTING AVISTA CORPORATION

Capital Additions for 2021

Project #	Business Case	2021 TTP (System)	Exh. HLR-2 Page #
Electric			
1	Clearwater Wind Generation Interconnection	$ 1,665	3
2	Colstrip Transmission	557,181	10
3	Distribution Grid Modernization	1,439,020	18
4	Distribution Minor Rebuild	10,704,598	30
5	Distribution System Enhancements	10,882,898	39
6	Distribution Transformer Change Out Program	146,381	53
7	Downtown Network - Asset Condition	1,739,460	61
8	Downtown Network - Performance & Capacity	1,802,785	77
9	Elec Relocation and Replacement Program	5,290,025	88
10	Electric Storm	16,878,877	95
11	Joint Use	2,140,043	102
12	LED Change-Out Program	249,741	109
13	Meter Minor Blanket	258,680	118
14	New Revenue - Growth	44,512,539	124
15	Primary URD Cable Replacement	30,463	131
16	Protection System Upgrade for PRC-002	6,275,878	135
17	Saddle Mountain 230/115kV Station (New) Integration Project Phase 1	2,345,100	141
18	Saddle Mountain 230/115kV Station (New) Integration Project Phase 2	16,997,122	144
19	SCADA - SOO and BuCC	1,768,448	151
20	Spokane Smart Circuit	550,569	159
21	Spokane Valley Transmission Reinforcement Project	15,066,069	161
22	Substation - New Distribution Station Capacity Program	2,154,498	168
23	Substation - Station Rebuilds Program	4,928,628	175
24	Transmission - Minor Rebuild	3,758,818	182
25	Transmission Construction - Compliance	2,133,304	188
26	Transmission Major Rebuild - Asset Condition	16,128,097	197
27	Transmission NERC Low-Risk Priority Lines Mitigation	1,025,277	204
28	Westside 230/115kV Station Brownfield Rebuild Project	7,019,954	210
29	Wood Pole Management	14,411,440	217
30	WSDOT Control Zone Mitigation	505,854	229
Total Electric		**$ 191,703,414**	
General Plant and Other Plant			
31	Apprentice/Craft Training	$ 76,115	236
32	Capital Tools & Stores	2,436,781	241
33	Fleet Services Capital Plan	5,533,378	252
34	Gas Operator Qualification Compliance	49,470	264
35	Jackson Prairie Joint Project	2,197,634	270
36	Strategic Initiatives	(271,509)	275
37	Structures and Improvements/Furniture	3,597,435	281
38	Telematics 2025	959,250	297
39	Washington Advanced Metering Infrastructure Project	2,430,992	308
Total General Plant and Other Plant		**$ 17,009,545**	
Natural Gas			
40	Gas Cathodic Protection Program	$ 94,812	315
41	Gas Cheney HP Reinforcement	2,841,302	318
42	Gas Facility Replacement Program (GFRP) Aldyl A Pipe Replacement	22,555,185	323
43	Gas HP Pipeline Remediation Program	706,188	337
44	Gas Isolated Steel Replacement Program	1,041,477	340
45	Gas Non-Revenue Program	9,538,316	343
46	Gas Overbuilt Pipe Replacement Program	204,526	348
47	Gas PMC Program	2,507,677	352
48	Gas Regulator Station Replacement Program	1,161,440	355
49	Gas Reinforcement Program	883,675	359
50	Gas Replacement Street and Highway Program	3,345,236	363
51	Gas Telemetry Program	219,574	366
52	New Revenue - Growth	34,169,147	124
Total Natural Gas		**$ 79,268,557**	
Exh. HLR-1T Total 2021 Capital Additions		**$ 287,981,516**	

Provisional Capital Additions for 2022-2024 by Plant Group
Rosentrater

WA GRC Plant Group	Project #	Business Case	2022 TTP (System)	2023 TTP (System)	2024 TTP (System)	Exh. HLR-2 Page #
Large Distinct Projects	53	Central 24 HR Operations Facility	$ -	$ -	$ 4,598,545	370
	54	Jackson Prairie Joint Project	2,378,977	2,369,965	2,420,989	270
	55	N Lewiston Autotransformer - Failed Plant	5,554,506	-	-	381
	56	Oil Storage Improvements	-	1,762,827	-	389
	57	Strategic Initiatives	2,297,174	-	-	275
	58	Telematics 2025	438,347	808,250	-	297
	59	Transmission Major Rebuild - Asset Condition	5,680,751	12,000,000	11,000,000	197
Total Large Distinct Projects			**$ 16,349,755**	**$ 16,941,042**	**$ 18,019,534**	
Mandatory & Compliance	60	Colstrip Transmission	$ 325,001	$ 370,002	$ 639,999	10
	61	Elec Relocation and Replacement Program	5,399,944	5,399,984	5,399,987	88
	62	Gas Above Grade Pipe Remediation Program	682,000	714,000	709,000	400
	63	Gas Cathodic Protection Program	715,000	715,000	715,000	315
	64	Gas Facility Replacement Program (GFRP) Aldyl A Pipe Replacement	25,687,251	27,687,251	24,444,163	323
	65	Gas HP Pipeline Remediation Program	599,998	-	-	337
	66	Gas Isolated Steel Replacement Program	862,754	850,008	850,008	340
	67	Gas PMC Program	3,500,004	3,799,993	1,500,000	352
	68	Gas Replacement Street and Highway Program	3,495,650	3,500,000	3,500,000	363
	69	Gas Transient Voltage Mitigation Program	875,000	965,000	250,000	407
	70	Joint Use	2,749,992	2,950,008	2,950,008	102
	71	Protection System Upgrade for PRC-002	80,000	11,879,164	-	135
	72	Saddle Mountain 230/115kV Station (New) Integration Project Phase 2	19,962,533	-	-	144
	73	Spokane Valley Transmission Reinforcement Project	2,000,000	-	-	161
	74	Transmission Construction - Compliance	2,111,069	1,550,000	-	188
	75	Transmission NERC Low-Risk Priority Lines Mitigation	2,554,255	2,499,984	-	204
	76	Tribal Permits & Settlements	259,776	249,996	249,996	413
	77	Westside 230/115kV Station Brownfield Rebuild Project	-	-	8,924,475	210
	78	WSDOT Control Zone Mitigation	749,998	1,200,005	1,399,999	229
Total Mandatory & Compliance			**$ 72,610,225**	**$ 64,330,395**	**$ 51,532,635**	
Programs	79	Capital Tools & Stores	$ 2,500,008	$ 2,500,008	$ 2,500,008	241
	80	Distribution Grid Modernization	2,165,010	2,239,852	794,988	18
	81	Distribution Minor Rebuild	11,499,986	11,499,986	10,999,980	30
	82	Distribution System Enhancements	6,930,025	7,069,995	7,000,013	39
	83	Downtown Network - Asset Condition	1,600,000	1,999,999	2,400,000	61
	84	Downtown Network - Performance & Capacity	1,100,000	1,150,000	1,200,000	77
	85	Electric Storm	6,023,406	6,000,012	6,000,012	95
	86	Fleet Services Capital Plan	7,904,640	5,608,016	5,423,704	252
	87	Gas Airway Heights HP Reinforcement	9,634,502	-	-	420
	88	Gas Non-Revenue Program	9,295,000	8,500,010	8,500,010	343
	89	Gas Pullman HP Reinforcement Project	-	-	2,400,004	425
	90	Gas Regulator Station Replacement Program	985,579	1,000,002	799,999	355
	91	Gas Reinforcement Program	1,299,997	1,299,999	1,300,002	359
	92	Gas Telemetry Program	303,256	210,004	210,004	366
	93	LED Change-Out Program	299,964	299,964	299,964	109
	94	New Revenue - Growth	73,429,598	67,348,997	67,371,967	124
	95	SCADA - SOO and BuCC	1,026,882	736,223	699,972	151
	96	Structures and Improvements/Furniture	3,639,388	3,349,639	3,349,609	281
	97	Substation - New Distribution Station Capacity Program	5,765,300	11,076,449	12,701,549	168
	98	Substation - Station Rebuilds Program	12,998,326	58,412,186	41,493,604	175
	99	Transmission - Minor Rebuild	3,400,375	3,343,418	3,343,419	182
	100	Transmission - Performance & Capacity	-	-	8,500,000	429
	101	Wood Pole Management	12,999,996	12,999,996	12,999,996	217
Total Programs			**$ 174,801,238**	**$ 206,644,755**	**$ 200,288,804**	
Exh. HLR-1T Total 2022-2024 Provisional Capital Additions			**$ 263,761,218**	**$ 287,916,192**	**$ 269,840,973**	

Clearwater Wind Generation Interconnection

EXECUTIVE SUMMARY

Avista is a joint owner in the 500kV Colstrip Transmission System and party to the Colstrip Project Transmission Agreement ("Agreement"). Under Federal Energy Regulatory Commission ("FERC") rules and the Agreement, Avista must comply with all rules and procedures governing the interconnection of new generation facilities with the Colstrip Transmission System. Pursuant to the Agreement, Clearwater Energy Resources, LLC requested interconnection of a 750MW wind project at Broadview ("Clearwater Wind Project"), all required study processes were completed, and Avista executed a Large Generator Interconnection Agreement with the developer on May 22, 2019 ("LGIA").

Avista and the joint owners of the Colstrip Transmission System are obligated to fund their respective shares of all Transmission Provider Interconnection Facilities and Network Upgrades applicable to the interconnection of a Large Generator Interconnection project. Failure to fund this project will result in Avista being in breach of both the Agreement and the LGIA, and would be a violation of FERC rules governing generation interconnection. Such obligations arise from Avista's ownership in the Colstrip Transmission System, which has benefited Avista retail native load customers over the life of the Colstrip Project.

Avista's allocation of costs for the construction of required facilities for the Clearwater Wind Project was originally estimated to be $650,600, in 2018 dollars. The original Business Case was submitted and approved, July, 2019. Overall project cost was reduced to $570,000 per the in-year adjustment request approved June 17, 2020. Applicable service code and jurisdiction are 098-ED, common system-wide, electric direct.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Jeff Schlect*	*Initial narrative drafted from pre-existing approved case*	*7/30/2020*	*Existing Approved Case*

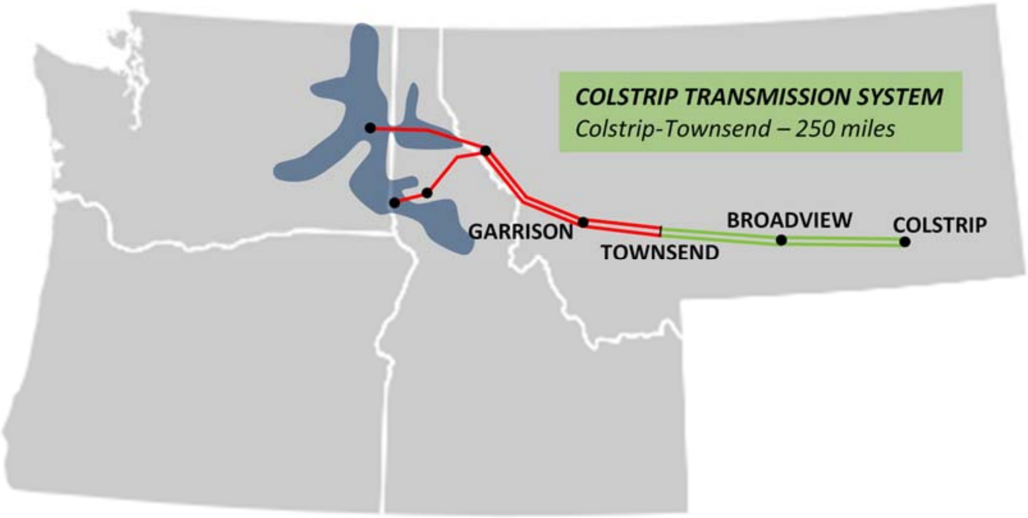
Clearwater Wind Generation Interconnection

GENERAL INFORMATION

Requested Spend Amount	$570,000
Requested Spend Time Period	*2 years (2020-2021)*
Requesting Organization/Department	Energy Delivery / Transmission Services
Business Case Owner | Sponsor	Jeff Schlect | Heather Rosentrater / Mike Magruder
Sponsor Organization/Department	Energy Delivery / Transmission Services
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

Per the Agreement, Avista is a joint owner (joint tenants in common) of the Colstrip Transmission System, which consists of approximately 250 miles of double circuit 500kV transmission facilities extending from the Colstrip Project westward to the Broadview 500kV Substation and the Townsend point of interconnection between the Colstrip Transmission System and the Bonneville Power Administration's Eastern Intertie 500kV facilities[1]. Under FERC rules and the Agreement, Avista must comply with all rules and procedures governing the interconnection of new generation facilities with the Colstrip Transmission System. Pursuant to the Agreement, Clearwater Energy Resources, LLC requested interconnection of its 750MW Clearwater Wind Project to the Colstrip Transmission System at Broadview. All required study processes were completed and Avista executed a Large Generator Interconnection Agreement with the developer on May 22, 2019 ("LGIA").



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[1] Avista owns a 10.2% share in the Colstrip-Broadview segment and a 12.1% share in the Broadview-Townsend segment.

Clearwater Wind Generation Interconnection

Avista and the joint owners of the Colstrip Transmission System are obligated to fund their respective shares of all Transmission Provider Interconnection Facilities and Network Upgrades applicable to the interconnection of a Large Generator Interconnection project. NorthWestern Energy ("NWE") performs all Transmission Operator functions under the Agreement, including construction budgeting and forecasting for Colstrip Transmission System facilities. Avista's allocation of costs for the construction of required facilities for the Clearwater Wind Project was originally estimated to be $692,000 to be split equally between 2020 and 2021. An updated forecast received from NorthWestern Energy on June 1, 2020, outlined an overall project decrease (from $692,000 to $570,000) along with a timing adjustment between 2020 and 2021 (2020 - $110,000; 2021 - $460,000).

1.1 What is the current or potential problem that is being addressed?

Pursuant to the Agreement and its mandatory compliance requirements with FERC generation interconnection rules, the Company must fund its applicable ownership share of constructions costs associated with generation interconnection projects, including the Clearwater Wind Project.

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 applicable driver for the Company's construction investment in FERC jurisdictional generation interconnection projects *Mandatory & Compliance.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

Failure by the Company to provide construction funding for this project would be: (i) an act of default under Section 25 of the Agreement, (ii) an act of default under the LGIA, and (iii) a violation of FERC rules pursuant to which the Company could incur compliance penalties of up to $1 million per day. The Clearwater Wind Project is currently planned for completion in 2021 but, depending upon action or inaction by the developer under the LGIA, the project and related funding may be delayed.

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.

Appendix B to the LGIA incorporates construction milestones for the project.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

Clearwater Wind Project #234 Feasibility Study Report (NWE)
Clearwater Wind Project #234 System Impact Study Report (NWE)
Clearwater Wind Project #234 Facilities Study Report (NWE)

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.

Not applicable

The Company must fund its allocated share of capital improvements under the Colstrip Transmission Agreement, the LGIA and FERC rules.

Option	**Capital Cost**	**Start**	**Complete**
Fund Network Upgrades under LGIA	*$570,000*	*01 2020*	*12 2021*
Default on agreements and violate FERC rules	*N/A*	*N/A*	*N/A*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Not applicable – Mandatory and Compliance driver

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.

2020 – Design, engineering and procurement

2021 – Construction

No related O&M reductions are expected with this project

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Capital funding only; no engineering or construction labor impacts to the Company. NWE performs all construction and administration activities as Transmission Operator under the Agreement.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Not applicable (only alternative is to not fund as outlined under 1.3 above)

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. spend, and transfers to plant by year.

NWE, as the Transmission Operator under the Agreement, manages the Colstrip Transmission System construction program. Investments become used and useful and are placed in service following construction completion and energization.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Business Case investment upholds the Company's Code of Conduct and is consistent with its lasting values. Such investment complies with applicable contract obligations and FERC rules.

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.

Capital investment under this Business Case is mandatory – required by contract and FERC rules. As outlined in 1.3 above, failure by the Company to provide construction funding for this project would be: (i) an act of default under Section 25 of the Agreement, (ii) an act of default under the LGIA, and (iii) a violation of FERC rules pursuant to which the Company could incur compliance penalties of up to $1 million per day.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Counterparties to the Colstrip Transmission Agreement, joint owners of the Colstrip Transmission System, and joint parties to the LGIA – NorthWestern Energy, PacifiCorp, Portland General Electric and Puget Sound Energy

LGIA Counterparty – Clearwater Energy Resources, LLC

Bonneville Power Administration – Transmission entity interconnecting with the Colstrip Transmission System at the point of change of ownership near Townsend, MT

2.8.2 Identify any related Business Cases

Colstrip Transmission

3.1 Steering Committee or Advisory Group Information

The Colstrip Transmission Committee, of which the Company is a member, meets periodically to review construction funding associated with the Colstrip Transmission System, including generation interconnection projects. The Company's Transmission Services department administers the LGIA.

3.2 Provide and discuss the governance processes and people that will provide oversight

Pursuant to Section 22 of the Agreement, the Colstrip Transmission Committee is established to facilitate cooperation, interchange of information and efficient management of the Colstrip Transmission System. The Colstrip Transmission Committee consists of five members, each designated by one of the parties to the Agreement. Each committee member has the right to vote their party's ownership share in the Colstrip Transmission System. The Company's Transmission Services department participates on the Colstrip Transmission Committee and administers the LGIA.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Such items are reviewed by the Colstrip Transmission Committee and documented by NWE as the Transmission Operator under the Agreement.

The undersigned acknowledge they have reviewed the Clearwater Wind Generation Interconnection 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: Date:

Print Name: Jeff Schlect

Title: Senior Manager, FERC Policy and Transmission Services

Role: Business Case Owner

Signature: Date:

Print Name: Mike Magruder

Title: Director, Transmission Operations and System Planning

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

The undersigned acknowledge they have reviewed the Clearwater Wind Generation Interconnection 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: Jeff Schlect Digitally signed by Jeff Schlect Date: 2020.07.30 17:30:45 -07'00' Date: 7/30/2020
Print Name: Jeff Schlect
Title: Senior Manager, FERC Policy and Transmission Services
Role: Business Case Owner

Signature: Michael A. Magruder Digitally signed by Michael A. Magruder Date: 2020.07.31 12:22:28 -07'00' Date: 7/31/2020
Print Name: Mike Magruder
Title: Director, Transmission Operations and System Planning
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Colstrip Transmission

EXECUTIVE SUMMARY

Avista is a joint owner in the 500kV Colstrip Transmission System and party to the Colstrip Project Transmission Agreement ("Agreement"). Avista and the joint owners are obligated to fund their respective shares of the Colstrip Transmission System construction and maintenance budgets, as approved by the Colstrip Transmission Committee, which consists of representatives of each of the parties to the Agreement. The Colstrip Transmission Committee reviews and approves, on an annual basis, the capital and O&M expense program proposed by NorthWestern Energy ("NWE") (the designated Transmission Operator under the Agreement). Pursuant to Section 22 of the Agreement, Avista provides annual input to, and approval for, the Colstrip Transmission System capital and O&M expense program commensurate with its ownership shares in the Colstrip Transmission System.[1]

In conjunction with the Company's ownership interest in Colstrip Project Units 3 and 4, the Colstrip Transmission System has benefited the Company's retail native load customers since the early 1980's. To continue to reliably integrate the Company's Colstrip Project resources to native load and to meet applicable NERC transmission planning and operational reliability standards, the Colstrip Transmission System must be maintained. Examples of recent and pending capital expenditures in the Colstrip Transmission System include end-of-life replacement of 500kV power circuit breakers at the Colstrip 500/230kV Station and 500kV structure relocation to mitigate erosion risk caused by high runoff in the Little Big Horn River.

Colstrip Transmission program expenditures have averaged $348,000 over the past ten years. NWE's latest draft plan was released in July, 2020, outlining a five-year (2020-2024) average program expense of $516,000. The original Business Case was submitted and approved in April, 2017. Applicable service code and jurisdiction are 098-ED, common system-wide, electric direct.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Jeff Schlect*	*Initial narrative drafted from pre-existing approved case*	*7/28/2020*	*Existing Approved Case*

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[1] Avista owns a 10.2% share in the Colstrip-Broadview segment and a 12.1% share in the Broadview-Townsend segment.

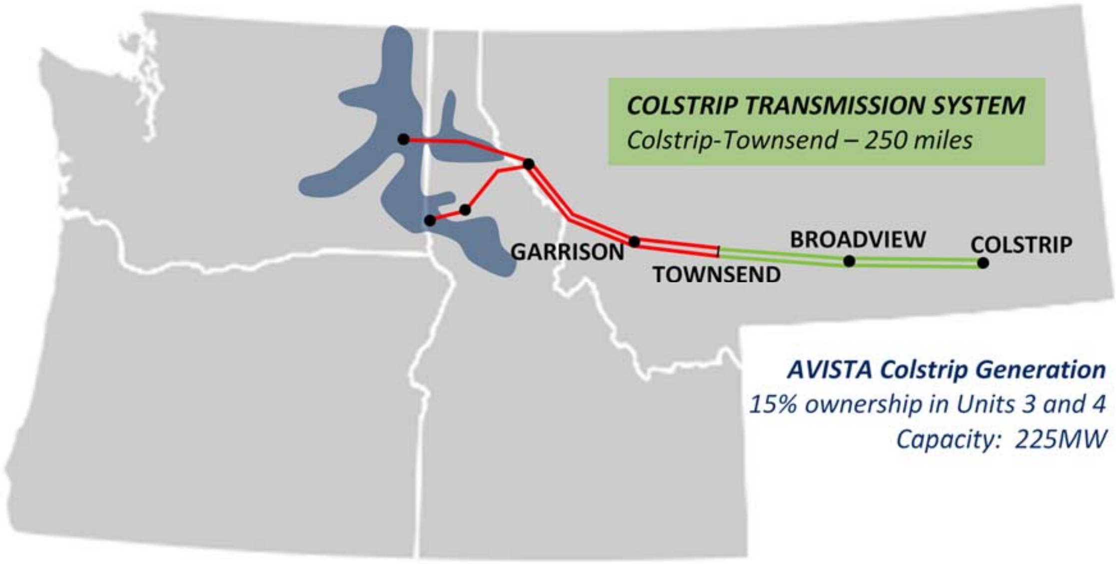
Colstrip Transmission

GENERAL INFORMATION

Requested Spend Amount	$724,000 (2021)
Requested Spend Time Period	*Ongoing Annual Program*
Requesting Organization/Department	Energy Delivery / Transmission Services
Business Case Owner | Sponsor	Jeff Schlect | Heather Rosentrater / Mike Magruder
Sponsor Organization/Department	Energy Delivery / Transmission Services
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

As part of the construction and integration of Colstrip Units 3 and 4 in the early 1980s for the benefit of the Company's native load retail customers, the Colstrip project participants constructed the Colstrip Transmission System, approximately 250 miles of double circuit 500kV transmission facilities extending from the Colstrip Project westward to the Broadview 500kV Substation and the Townsend point of interconnection between the Colstrip Transmission System and the Bonneville Power Administration's Eastern Intertie 500kV facilities.



Avista owns a 15% share of Colstrip Units 3 and 4 (approximately 225MW). Reliable operation of the Colstrip Transmission System is necessary to transfer Colstrip output to the respective systems of each joint project owner, including Avista (other project owners are: NorthWestern Energy, PacifiCorp, Portland General Electric and Puget Sound Energy). Avista and the other joint project owners are party to the Colstrip Project Transmission Agreement which, among other things, obligates Avista to fund its commensurate share of all construction and maintenance expenses for the ongoing operation, maintenance, renewal and replacement of the jointly owned Colstrip Transmission System facilities.

Examples of recent expenditures in the Colstrip Transmission System are noted in Section 2.2 below.

As NERC transmission planning and operational reliability standards[2] evolve, compliance with both operational and planning standards may require replacement of, or upgrades to, Colstrip Transmission System facilities.

1.1 What is the current or potential problem that is being addressed?

Pursuant to the Agreement, the Company must fund its applicable ownership share of capital improvements to the jointly owned Colstrip Transmission System.

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 Company's capital investment in the Colstrip Transmission System is driven by its contractual obligations under the Agreement (*Mandatory & Compliance*). Related drivers include *Asset Condition* and *Failed Plant & Operations.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

Failure to fund its allocated share of costs under the Agreement will put the Company into default and would eliminate the Company's right to use the Colstrip Transmission System to integrate its resources for service to its bundled retail native load customers.

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.

Not applicable

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

Not applicable

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.

Not applicable

The Company must fund its allocated share of capital improvements under the Colstrip Transmission Agreement.

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[2] Among its other provisions, the U.S. Energy Policy Act of 2005 provided for the establishment of mandatory reliability standards and authorized the Federal Energy Regulatory Commission (FERC) to assess penalties of up to $1 million per day per violation for non-compliance with these standards and other FERC regulations. FERC has certified the North American Electric Reliability Organization (NERC) to establish and enforce these reliability standards. The Company has a statutory obligation to plan, improve, upgrade, and operate its transmission system, including the Colstrip Transmission System, to maintain compliance with these standards and is required to self-certify its compliance with these standards on an annual basis.

Colstrip Transmission

Option	Capital Cost	Start	Complete
Fund capital program under the Agreement	*$516,000*	*1981*	*Ongoing*
Do not fund – Contract default	*Undetermined*	---	---

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Additional Information – In addition to upholding the Company's contractual obligations and maintaining the ability to integrate its Colstrip generation output for service to its bundled retail native load customers, Colstrip Transmission program funding also provides the Company a future transmission alternative for consideration under the Company's Integrated Resource Planning process, to integrate potential renewable resources located in Montana.

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.

Capital amounts are used for improvements, renewals and replacements of Colstrip Transmission System assets. Examples of recent expenditures in the Colstrip Transmission System include:

- End-of-life replacement of 500kV power circuit breakers at the Colstrip 500/230kV Substation
- Erosion mitigation caused by record high runoff in the Big Horn River, threatening the stability of two 500kV structures
- Construction of optical ground wire (OPGW) communication facilities between Broadview and Colstrip to meet dual communication path requirements under North American Electric Reliability Corporation (NERC) standards
- 500kV relay replacements
- Hardware, software and operating system upgrades to maintain compliance with applicable operating standards

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Capital funding only; no engineering or construction labor impacts to the Company. NWE performs all construction and construction administration activities as Transmission Operator under the Agreement.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Not applicable (only alternative is to not fund and default on contract)

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. spend, and transfers to plant by year.

NWE, as the Transmission Operator under the Agreement, manages the Colstrip Transmission System construction program. Program investments, as improvements, renewals and replacements for the existing Colstrip Transmission System, become used and useful each year upon being placed in-service.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Program investment upholds the Company's Code of Conduct and is consistent with its lasting values. Colstrip Transmission System investment maintains the Company's ability to integrate its Colstrip generation assets for service to bundled retail native load customers and provides the Company with a future transmission alternative to integrate potential renewable resources located in Montana.

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.

Capital investment under the program is mandatory – required by contract – pursuant to the Agreement. The Company's ongoing ownership in the Colstrip Transmission System may be evaluated consistent with its assessment of potential future resource acquisitions in Montana under the Company's Integrated Resource Planning activities.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista Power Supply – Internal customer for the integration of resources designated for service to bundled retail native load customers

Counterparties to the Colstrip Transmission Agreement and joint owners of the Colstrip Transmission System – NorthWestern Energy, PacifiCorp, Portland General Electric and Puget Sound Energy

Bonneville Power Administration – Transmission entity interconnecting with the Colstrip Transmission System at the point of change of ownership near Townsend, MT

2.8.2 Identify any related Business Cases

Clearwater Wind Generation Integration

3.1 Steering Committee or Advisory Group Information

Pursuant to Section 22 of the Agreement, Avista provides annual input to, and approval for, the Colstrip Transmission System capital and O&M expense program commensurate with its ownership shares in the Colstrip Transmission System. The Colstrip Transmission Committee, of which the Company is a member, meets periodically to review, and provide recommendations for, the annual capital program administered by NWE. The Colstrip Transmission Committee provides approval for each year's capital program.

3.2 Provide and discuss the governance processes and people that will provide oversight

Pursuant to Section 22 of the Agreement, the Colstrip Transmission Committee is established to facilitate cooperation, interchange of information and efficient management of the Colstrip Transmission System. The Colstrip Transmission Committee consists of five members, each designated by one of the parties to the Agreement. Each committee member has the right to vote their party's ownership share in the Colstrip Transmission System. Section 22(f) of the Agreement outlines all matters that shall be submitted to the committee by NWE for approval, including Colstrip Transmission System construction and operating budgets.

With respect to long-term continuing ownership and participation in the Colstrip Transmission System, the Company's Power Supply and Transmission Services groups will, under the Company's Integrated Resource Planning process, analyze and assess such costs and benefits related to the integration of potential renewable resources located in Montana.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Such items are reviewed by the Colstrip Transmission Committee and documented by NWE as the Transmission Operator under the Agreement.

The undersigned acknowledge they have reviewed the Colstrip Transmission 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: ____________ Date: ________

Print Name: Jeff Schlect

Title: Senior Manager, FERC Policy and Transmission Services

Role: Business Case Owner

Signature: ____________ Date: ________

Print Name: Mike Magruder

Title: Director, Transmission Operations and System Planning

Role: Business Case Sponsor

Signature: ____________ Date: ________

Print Name: ____________

Title: ____________

Role: Steering/Advisory Committee Review

Colstrip Transmission

Template Version: 05/28/2020

Colstrip Transmission

The undersigned acknowledge they have reviewed the Colstrip Transmission 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:	Jeff Schlect Digitally signed by Jeff Schlect Date: 2020.07.30 17:22:00 -07'00'	Date:	7/30/2020
Print Name:	Jeff Schlect		
Title:	Senior Manager, FERC Policy and Transmission Services		
Role:	Business Case Owner		

Signature:	Michael A. Magruder Digitally signed by Michael A. Magruder Date: 2020.07.31 12:21:25 -07'00'	Date:	7/31/2020
Print Name:	Mike Magruder		
Title:	Director, Transmission Operations and System Planning		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Distribution Grid Modernization

EXECUTIVE SUMMARY

Maintaining system reliability is an important part of providing quality service to Avista's customers. Planned investments in the distribution system are necessary to efficiently maintain reliability while keeping costs low for customers. The Grid Modernization Program (GMP) is the largest program focused on planned maintenance and improvements beyond wood poles driven by a comprehensive engineering analysis across Avista's 19,000 miles of electric distribution lines (Avista 2019 Quick Facts). The GMP's mission is to replace aging and failing infrastructure within the electric distribution system while also improving reliability and performance and capturing energy savings through the efficient use of company resources. Avista's distribution system has numerous facilities at, or near, the end of their useful life. Over decades, many of these were built to different construction standards using a wide variety of materials. These factors contribute to increased outages that take longer to restore and fall short of modern expectations that utilities face. The program benefits all Washington and Idaho electric customers and is intended to operate on a 60 year cycle averaging 190 circuit-miles addressed per year. The current average cost per mile requires a $28.88MM annual investment to achieve a 60 year cycle. The 60 year cycle is based on the average lifespan of distribution infrastructure, and the twenty year cycle of the Wood Pole Management Program (WPM) (Avista Utilities Electric Distribution Infrastructure Plan June 2017).

A systematic approach is recommended to address the rebuild and upgrade of the distribution system. This approach utilizes a prioritization method balancing feeder health, performance, and criticality. Design decisions are made through a consistent process and construction adheres to established overhead and underground standards. Upon the completed construction of GMP projects, customers benefit from improved system reliability, safety, and performance. These can be measured by a reduction in outage frequencies and durations in addition to power quality metrics. As Avista's distribution facilities continue to age, it becomes more important to be proactive in their replacement. Delaying the business case increases the likelihood and severity of various risks including equipment failure, wildfire, and energy losses. A delay would also impact the cycle time of WPM. Not approving the business case places the responsibility of rebuilding the system on the individual offices throughout the company which are responsible for daily maintenance and operations as well as new revenue projects. Additionally, it jeopardizes the ability to holistically address system wide performance. Overall, not funding or delaying this business case would reduce the efficiency that the GMP provides to the company and customers while elevating the risk of an inconsistent application of design and construction standards.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft		*Initial draft of original business case 2020*	*7/31/2020*	
1.0				

Distribution Grid Modernization

GENERAL INFORMATION

Requested Spend Amount	$77,000,000
Requested Spend Time Period	5 years
Requesting Organization/Department	Asset Maintenance
Business Case Owner | Sponsor	Heather Webster | Alicia Gibbs | David Howell
Sponsor Organization/Department	T51/Asset Maintenance
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Grid Modernization Program (GMP) addresses the aging and failing infrastructure found throughout the electric distribution system. Other issues addressed include sub-optimal system performance and inaccessible facilities that drive increased routine maintenance costs. Outage durations and frequencies and power quality problems are also evaluated for improvement through the installation of automated devices. Safety is also a key benefit of the Program as Grid Modernization projects bring facilities up to current NESC and Avista construction standards, fulfill the efforts of Wildfire Resiliency, address the Transformer Change Out Program, and address structures located within the control zone of roadways subject to Washington State's Department of Transportation Target Zero requirements.

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 GMP business case is driven by asset condition and performance and capacity. Customers benefit from in the following ways:

- Replacement of aging and failed infrastructure.
- Fewer outages that can be resolved more quickly.
- Automation devices produce results immediately optimizing system performance, reducing costs, and reducing outages.
- Cost effective work due to program efficiencies and long-term planning.
- Improved safety.
- Providing additional expertise with design and construction resources that are not available at outlying offices.

Reliability improvements have been quantified that are a direct benefit to the customers in feeders that the GMP has addressed. The analysis was performed by comparing reliability metrics in years before and after the GMP for all feeders completed through 2018. Figures 1-4 show these reliability metrics, and the raw data and analysis is located at:

c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Data\grid mod reliability data analysis before and after.xlsx

Distribution Grid Modernization

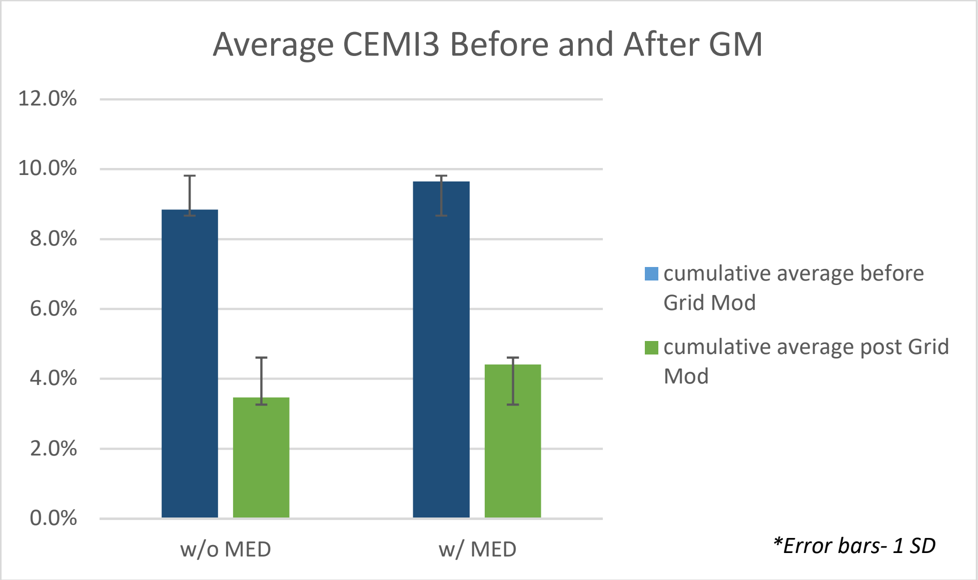


Figure 1: Average CEMI3 on feeders that have been fully addressed by GMP. This includes all the feeders completed through the end of 2018.

Figure 1 shows CEMI3 which is the percentage of customers experiencing 3 or more interruptions per year. The data show that customers on feeders that have been addressed by the Grid Modernization Program experience a 61% reduction when major event day (MED) are not included and a 54% reduction when MED are included.

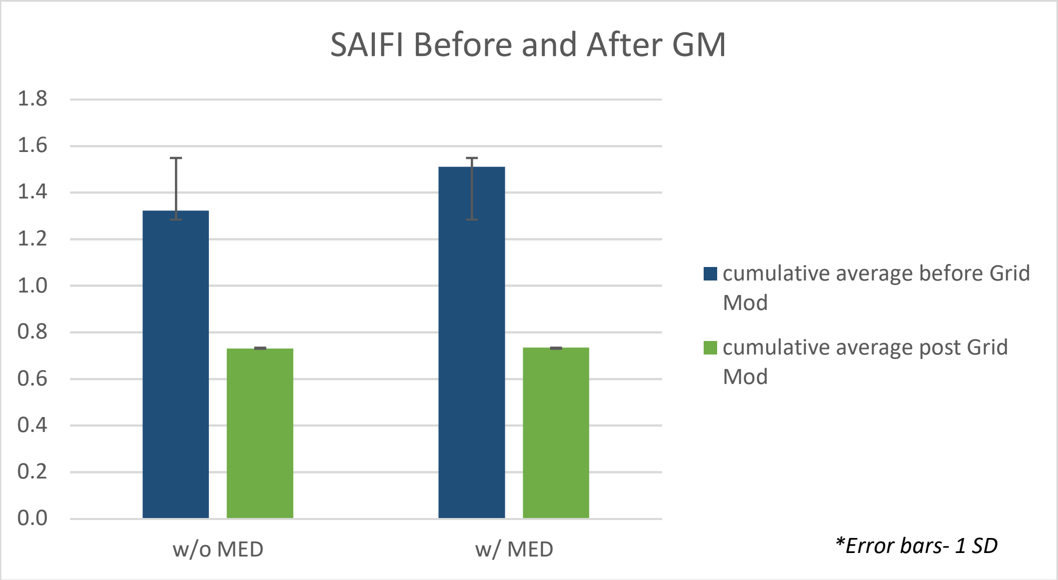


Figure 2: SAIFI before and after Grid Modernization on feeders completed through the end of 2018.

SAIFI is the sustained average interruption frequency index. The data show that customers on feeders addressed by the GMP experience a 51% reduction (with MED) and a 64% reduction in the duration of power interruptions.

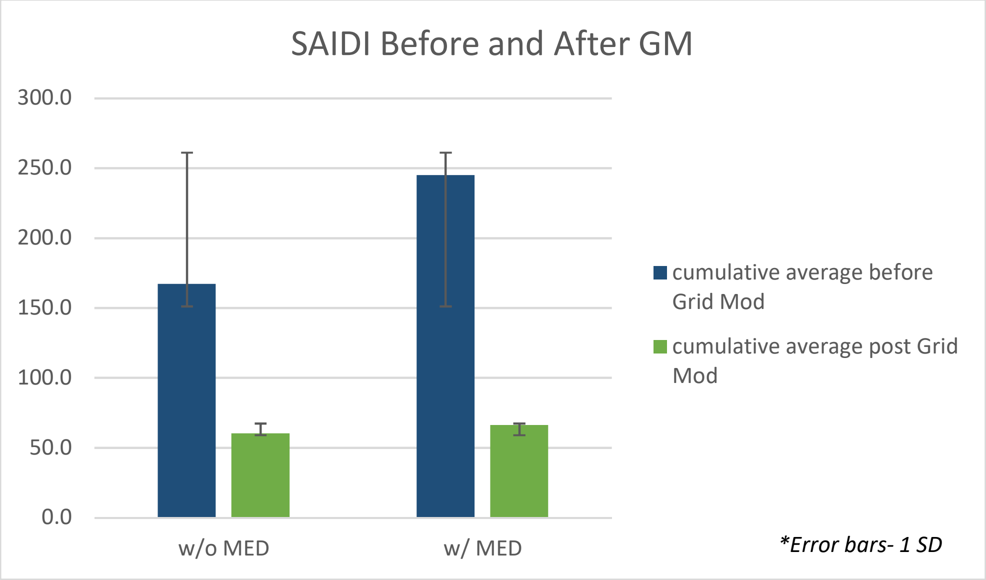


Figure 3: SAIDI before and after GMP for feeders completely addressed by the end of 2018.

SAIDI is the total duration of interruptions experienced by customers (in this case, the customers on one feeder). Customers on feeders addressed by the GMP experience a 64% reduction (without MED) and a 73% reduction with MED included. This means that outages customers experience are shorter in duration.

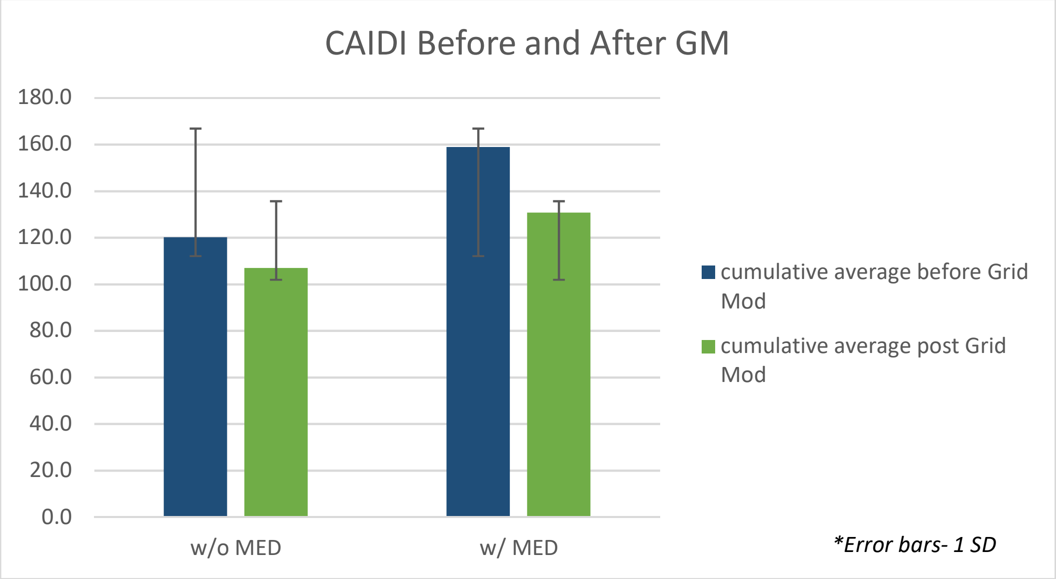


Figure 4: CAIDI before and after being addressed by the Grid Modernization Program.

CAIDI is the customer average duration index, which indicates the amount of time it takes to restore service. Customers experience an 11% reduction (without MED) and an 18% reduction with MED after GMP.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Delaying the work performed by the GMP would result in an increased risk of equipment failure, energy losses over time, expanded system maintenance costs, and unplanned outages. There would also be a lost opportunity to apply holistic and sustainable solutions following an in-depth engineering analysis to locations that experience recurring unplanned outages.

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 previously mentioned performance metrics; SAIFI, SAIDI, CAIDI, and CEMI3 can all be used to gauge system performance improvements after construction is completed. Voltage quality at any individual point along the feeder can also serve as an indicator of whether a project was successful. Across the entire program, an annual total of the feeder miles addressed serves as a measure of progress toward addressing the entire system across a 60 year cycle as intended.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Feeder Status Report: The feeder status report details the analysis of attributes of the distribution system in three major categories:

- Performance: Thermal utilization, efficiency, voltage regulation, reliability performance (MAIFI, CAIDI), power factor, FDR imbalance.
- Health: Age, OH/UG ratio, pole rejection rate, reliability health (CEMI3, SAIFI).
- Criticality: Essential services, commercial account density, customer density, load density.

c01m19:\Distribution Feeder Status Report\Feeder Status Report 2019\2019FeederStatusReport.xlsm

Using the information that the Feeder Status Report provides, each feeder is prioritized by a combined score assessing the three categories within a tool in the location below and selected to maintain a balance between work done in Washington and Idaho.

c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Feeder Selection

Feeder analysis reports: Once selected, a distribution engineer performs a thorough analysis on the entire circuit to determine what work is needed to make the feeder most efficient and to bring the feeder up to current standards to improve operation, safety, and support future loads. These reports are located at the following location:

c01m19:\Feeder Upgrades - Dist Grid Mod\~Feeder Analysis\

2017 Distribution Plan: The 2017 Distribution Plan summarizes a variety of topics including the different drivers for investing in system improvements and planned investments such as Grid Mod, which is cited often.

Avista Utilities Electric Distribution Infrastructure Plan June 2017: c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Data\Distribution Plan FINAL 2017.pdf

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 Distribution Feeder Status Report annually quantifies the performance, health, and criticality as outlined in section 1.5.1. More specifically, Wood Pole Management commissions inspections on selected Grid Modernization feeders identifying deteriorating, broken, and/or missing equipment. Individual reports can be found on the c01m19 feeder, the Feeder Upgrades – Dist Grid Mod folder, the specific feeder folder in question, and finally the ~Admin and Wood Pole Mgmt folders.

Option	Capital Cost	Start	Complete
[Recommended Solution] The Distribution Grid Modernization Program provides benefits to customers, employees, and shareholders by replacing problematic poles, cross-arms, cut-outs, transformers, conductor, etc. Additionally, automated line devices are installed which increase energy efficiency and system reliability. The 2021 request is $10MM to begin ramping up to the $28.88MM necessary to maintain a 60 year program cycle.	$28.88MM annually	01 2012	12 2072
[Alternative #1] Address issues through the different specific company initiatives, such as WPM, TCOP, URD, Segment Reconductor, etc. This means that a crew would potentially go out to the same area multiple times. This costs more for set up, travel time, flagging, etc. which means higher rates for customers. It also means the customer could have multiple planned outages and be impacted by multiple street closures for crews to address needed work at separate times. The risk reduction is also cut in half compared to the comprehensive work completed by GMP.	$UNK		

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The GMP capital request was calculated using a 60 year cycle as a goal while addressing almost 12,000 circuit-miles of electric distribution facilities. With the average spend rate of $152,000/mile over the past thirty months, an estimate of $28.88MM is determined.

When considering the prudency of this investment as part of a single program rather than spread across multiple departments, it is worth considering the design and construction support experience that GMP resources provide as a dedicated subject matter expert on projects. Other departments with competing priorities might find it difficult to maintain a focus on projects of this size. Another important benefit of work done is the O&M savings of each automated device that is installed. Using a thirty month long span of data over the past three years, the devices installed by GMP has saved the company an annual amount of $346,825. (c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Data\Automation device activation data and hard O&M costs.xlsx)

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.

[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.]

The capital cost of the Program is spread across numerous projects that typically span at least two years in a process summarized in Figure 5.

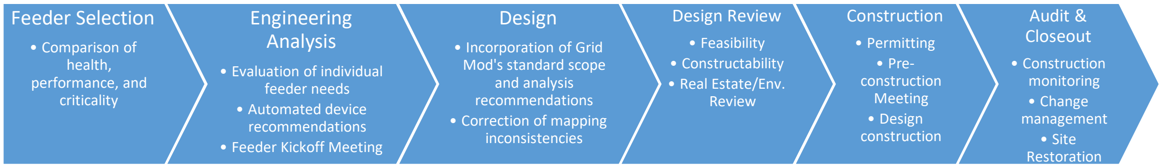


Figure 5: The Grid Modernization Project Life Cycle

Once metrics are gathered, individual feeders are evaluated to determine how they rank in comparison to the rest of the electric distribution system. Once chosen, the Program Engineer analyzes the feeder for opportunities to improve its reliability, power quality, potential for energy savings, and accessibility. That analysis is conveyed in a report to project stakeholders outlining feeder specific opportunities for improvement that have been agreed upon by individuals with experience in the area. Design follows the publishing of the report and in addition to feeder specific improvements, a set of standard criteria are applied to the existing equipment in the field. Designs are reviewed by subject matter experts evaluating the designs constructability and accuracy, real estate needs, and environmental and cultural risks. Construction then takes place along with an audit evaluating workmanship and accuracy relative to the design. Deviations are tracked through a design change order process. The project then moves towards completion as site restoration and accounting activities are completed.

Future O&M costs are reduced by relocating, removing, or converting sections of Avista facilities that present an opportunity to improve the feeder's performance. Vegetation Management costs are reduced by the removal of troublesome species that outpace routine maintenance cycles and the installation of automated devices reduces the need for servicemen to trouble shoot outages and performance issues.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

- **Wood Pole Management** – The GMP incorporates WPM's scope within its projects thereby assisting with its 20-year cycle target. Grid Modernization also relies on WPM for poles inspection reports.
- **Vegetation Management** – The GMP supports and relies on Vegetation Management during the course and completion of its projects. After design and prior to construction, trimming crews address any conflicts that a proposed design might have with existing vegetation. Upon the completion of a project, the GMP reduces the need for future tree trimming by targeting the removal of cycle-breaking species or the relocation and conversion of electric distribution infrastructure.
- **Real Estate** – Locations throughout the GMP designs are reviewed by the staff within the Real Estate department for conflicts that would arise during construction. Permitting is another consideration that is addressed once a design has been completed. The comprehensive GMP approach that partners with Real Estate's analysis results in the mitigation of outstanding issues that have existed in the field, thereby reducing a litigation risk to the company, and the establishment of sustainable alignments and corridors for Avista facilities.
- **Environmental Compliance** – Environmental items of concern are addressed during design and prior to the construction of proposed GMP work. Examples include avian and wildlife protection, the avoidance of any impact on cultural and heritage sites, and the impacts a project may have on public lands managed by tribal, municipal, state, and federal agencies.
- **Segment Reconductor and FDR Tie** – The GMP's holistic approach on feeders selected after a thorough prioritization process addresses issues that might otherwise be included on segment reconductor and FDR tie projects. The investment of Grid Modernization funding on selected feeders improves local office resource availability.
- **Distribution Minor Rebuild** – GMP's holistic approach on feeders selected after a thorough prioritization process addresses issues that might otherwise be included on minor rebuild projects. The investment of Grid Modernization funding on selected feeders improves local office resource availability.
- **Wildfire Resiliency** – The GMP incorporates efforts to reduce the risk of wildfires caused by electric distribution lines by relocating or converting lines in addition to the scope of the Wildfire Resiliency program.
- **Distribution Transformer Change Out Program (TCOP)** – The GMP incorporates the replacement of PCB transformers into each of its projects fulfilling the objective of the TCOP and reducing environmental risks and liabilities to the company and customers.
- **LED Change-Out Program** – The GMP incorporates the replacement of outdated streetlights to fulfill the mission of the LED Change-Out Program across its projects.
- **Primary URD Cable Replacement** – The GMP incorporates the replacement of outdated underground cable to fulfill the objective of Primary URD Cable Replacement across its projects.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Replacing equipment upon failure is an alternative to the GMP business case. It would maximize the value of an individual piece of equipment but result in numerous unplanned outages that could arise from and be the cause of unsafe situations to employees and customers. To mitigate the increase of unplanned outages, additional crews would be needed for trouble responses. Aside from a dedicated resource to respond, a variety of equipment and materials would also need to be available to minimize the impact of system failures.

GMP's scope could be addressed through various company initiatives such as WPM, TCOP, Primary URD Cable Replacement, Segment Reconductor and FDR Tie, etc. Given the poor condition of selected GMP feeders, it would certainly mean that the different initiatives would visit the same location multiple times over a short period resulting in elevated mobilization costs and disturbances to customers and communities as crews complete their work. The additional costs of working on the same feeder through multiple initiatives would be evident in increased rates. A possible solution to these issues would be to attempt a large coordination effort with a single construction resource that would receive all work packages from each initiative and attempt to carry out their construction simultaneously.

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. spend, and transfers to plant by year.

Work across the program is intended to be completed on a 60 year cycle becoming used and useful throughout each year as projects are constructed. Figure 5 above (Section 2.2) illustrates the life cycle of individual projects that can last at least two years.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

GMP aligns with Avista's mission: We improve our customers' lives through innovative energy solutions. Safely, Responsibly, and Affordably. We put those we serve at the center of everything that we do. GMP directly improves the lives of our customers by improving system reliability and performance by planning the work to minimize costs of long-term maintenance or unplanned work to maintain the distribution system. The collaboration that takes place throughout the program improves results upon the completion of each project: an efficient delivery experienced by customers and communities and a reduced risk to Shareholders.

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

- By addressing necessary work on the distribution system through the work of one program, there are reduced costs to the customer due to mobilizing crews one time, closing roads, and having planned outages one time instead of many times.
- The GMP plans work ahead of time and invests in the feeders that will receive the highest benefit from the scope of the program. The efficiency of this work is planned through earned value measurements which track the cost and schedule efficiency of the work compared to plan. The planning and tracking of the program use best project management practices.

- The work that will be performed on the program is planned through a thorough engineering analysis and the designs go through a full design review process to ensure that any replacements are prudent and in the best interest of the customer. This prevents work that is out of scope or does not provide adequate benefit from being added to the plan.
- Auditing the completed work ensures that the work performed and charged for was included in the plan or managed and tracked through the approved design change order process.
- Competitive bidding ensures that the work is awarded in a manner that reduces risks and keeps costs lower.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal Customers/Stakeholders: Real Estate, Transmission Engineering, Distribution Engineering, Environmental Compliance, Construction Services, Electric Shop, Meter Shop, Area offices, Account Executives, Regional Business Managers, Avista line crews, WPM, Supply Chain, and Vegetation Management.

External Customers/Stakeholders: Electric distribution customers, Municipalities, State DOT's, US Army Corps of Engineers, Public Land Management agencies, Joint Users, Adjacent Utilities, Native Tribes, Community action groups, Contract line crews.

2.8.2 Identify any related Business Cases

Wood Pole Management, Primary URD Cable Replacement, LED Change-Out Program, Wildfire Resiliency, Distribution Transformer Change Out Program, Distribution Minor Rebuild, Segment Reconductor and FDR Tie

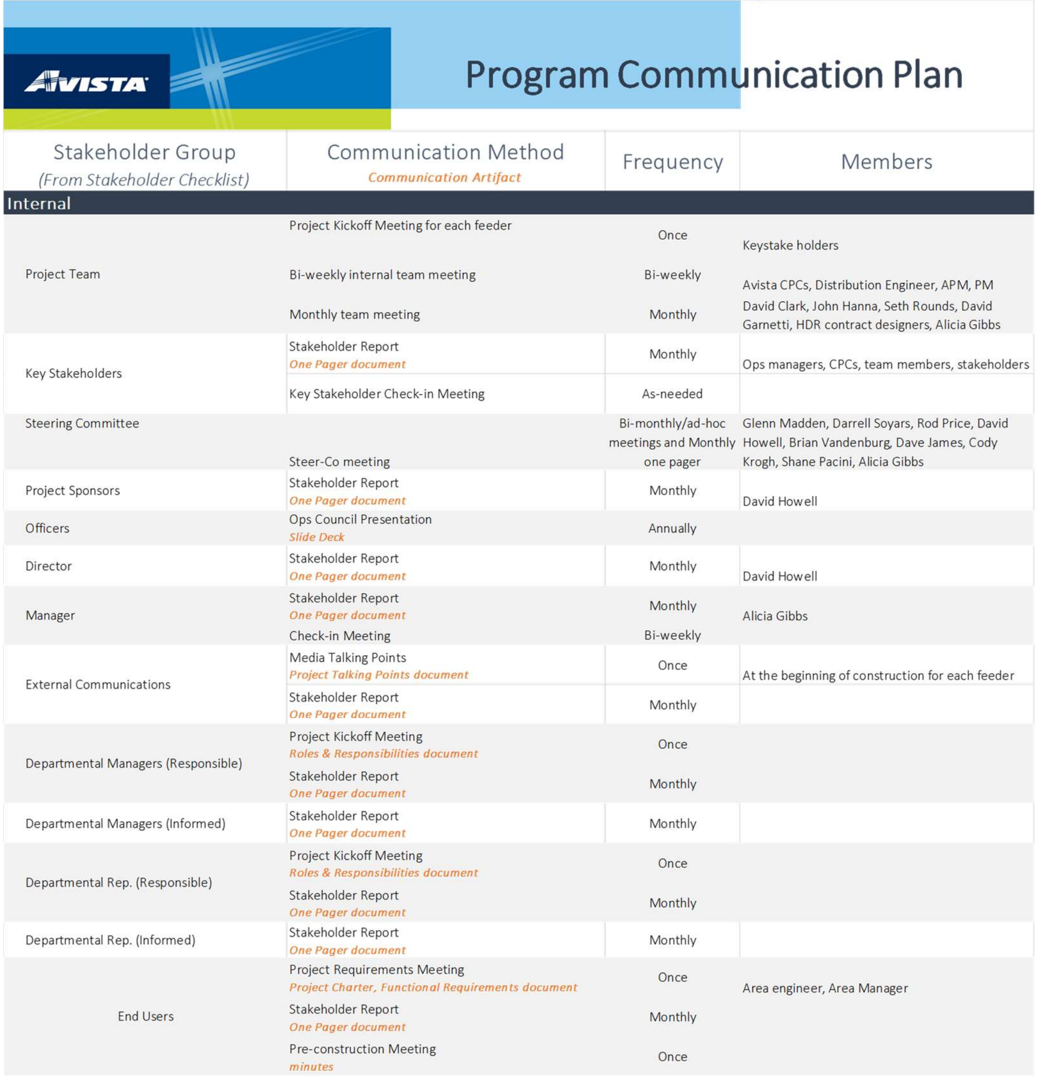
3.1 Steering Committee or Advisory Group Information

The steering committee is comprised of the project sponsor, Asset Maintenance Manager, Director of Operations, and the Asset Management Manager. This group meets as needed, usually annually, for an update on the program or when key program decisions or changes in scope need to be discussed. The members of this group are called out in the Grid Modernization Communication Management Plan.

Provide and discuss the governance processes and people that will provide oversight

The Grid Modernization Communication plan details the individuals that receive communication, the type of communication, and the frequency of communication. This document is located at: c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Admin\Project Management Plan

Documents\03 Communication Management Plan.docx



AVISTA

Program Communication Plan

Stakeholder Group *(From Stakeholder Checklist)*	Communication Method *Communication Artifact*	Frequency	Members
Internal			
Project Team	Project Kickoff Meeting for each feeder	Once	Keystake holders
	Bi-weekly internal team meeting	Bi-weekly	Avista CPCs, Distribution Engineer, APM, PM
	Monthly team meeting	Monthly	David Clark, John Hanna, Seth Rounds, David Garnetti, HDR contract designers, Alicia Gibbs
Key Stakeholders	Stakeholder Report *One Pager document*	Monthly	Ops managers, CPCs, team members, stakeholders
	Key Stakeholder Check-in Meeting	As-needed	
Steering Committee	Steer-Co meeting	Bi-monthly/ad-hoc meetings and Monthly one pager	Glenn Madden, Darrell Soyars, Rod Price, David Howell, Brian Vandenburg, Dave James, Cody Krogh, Shane Pacini, Alicia Gibbs
Project Sponsors	Stakeholder Report *One Pager document*	Monthly	David Howell
Officers	Ops Council Presentation *Slide Deck*	Annually	
Director	Stakeholder Report *One Pager document*	Monthly	David Howell
Manager	Stakeholder Report *One Pager document*	Monthly	Alicia Gibbs
	Check-in Meeting	Bi-weekly	
External Communications	Media Talking Points *Project Talking Points document*	Once	At the beginning of construction for each feeder
	Stakeholder Report *One Pager document*	Monthly	
Departmental Managers (Responsible)	Project Kickoff Meeting *Roles & Responsibilities document*	Once	
	Stakeholder Report *One Pager document*	Monthly	
Departmental Managers (Informed)	Stakeholder Report *One Pager document*	Monthly	
Departmental Rep. (Responsible)	Project Kickoff Meeting *Roles & Responsibilities document*	Once	
	Stakeholder Report *One Pager document*	Monthly	
Departmental Rep. (Informed)	Stakeholder Report *One Pager document*	Monthly	
End Users	Project Requirements Meeting *Project Charter, Functional Requirements document*	Once	Area engineer, Area Manager
	Stakeholder Report *One Pager document*	Monthly	
	Pre-construction Meeting *minutes*	Once	

How will decision-making, prioritization, and change requests be documented and monitored

- Decision making is documented in meeting minutes in the Program Onenote folder.
    - c01m19:\Feeder Upgrades - Dist Grid Mod\~Program Admin\Meetings & Presentations\~1Shared Grid Mod Program notebook
- The prioritization of feeder work is managed in the Feeder Selection management tool which is stored in the Grid Modernization drive. The prioritization is updated every one to two years with updated data from the Feeder Status Report. The feeders are then ranked based on equally weighted health, performance, and reliability scores. The top feeders may undergo an engineering analysis and gather feedback from area engineers to determine which order these feeders are selected in.
- Change requests are managed through a change order process. Any proposed changes that occur during construction to the approved designs are first evaluated, then approved, and tracked through the change order process.

The undersigned acknowledge they have reviewed the ***Distribution Grid Modernization*** 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: Heather Webster Date: 7/31/2020
Print Name: Heather Webster
Title: Asset Maintenance Project Mgr.
Role: Business Case Owner

Signature: David Howell David Howell Date: 7/31/2020
Print Name: David Howell
Title: Director of Operations
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Minor Rebuild

EXECUTIVE SUMMARY

The Distribution Minor Rebuild business provides a solution for the utility to address small unplanned asset failures and customer driven modifications to the distribution system but excludes fixes to the system considered to be maintenance. Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, providing response to unplanned damages to distribution assets not related to weather events, as well as responding to small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds, or replacements of asset units need to be completed to maintain system reliability and safety. This work impacts customers in WA and ID. By not funding, various types of work will need to be absorbed into some other funding due to the necessity of the work (i.e. the replacement of a car-hit pole in the alley, a broken cross-arm, a failed transformer, and other safety related projects.) Some minor rebuilds left unrepaired may not result in an immediate catastrophic failure. Over time an adverse accumulation of unrepaired assets would greatly put line workers and the general public at risk as minor asset failures begin to deteriorate pockets of the distribution system.

Historically costs for unplanned minor rebuild work have increased for several reasons. Many assets on the distribution system are past their end of life cycle and contributing to this increase. The 3-year average actual spend for minor rebuild work is $11,900,000 per year. This is expected to continue for the next 5 years. On average, Minor Rebuild spends approximately $1,000,000/month.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Draft of 2020 Business Case Refresh update*	*6/30/2020*	
02	*Amy Jones*	*Update to data on page 5*	*2/2/2021*	

Minor Rebuild

GENERAL INFORMATION

Requested Spend Amount	$10,000,000 annually
Requested Spend Time Period	Ongoing Program
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Amy Jones | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Distribution Minor Rebuild is an ongoing program that focuses on: keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, provides providing responsiveness response to unplanned damages to distribution assets not related to weather events, as well as responding to small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds or replacement of asset units need to be completed to maintain system reliability and safety.

The work includes; Asset Condition, NESC/Operating Standard Violation, Facility Upgrades, Facility Route Location Modification, Trouble and customer requests. Occasionally, larger projects with an identified need and short timeframe for implementation are constructed under the Distribution Minor Rebuild business case. Even though the work is unplanned, Minor Rebuild work occurs regularly due to the nature of the utility business and numerous assets in the field spread over a wide geographical area.

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 primary driver for the work is Asset Condition. This work focuses on keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, providing response to unplanned damages to distribution assets not related to weather events, as well as responding to small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds or replacements of asset units need to be completed to maintain system reliability and safety which are a benefit to customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Distribution Minor Rebuild work is one of the many components that support the overall reliability of the distribution system as well as responsiveness to customer requested service demands and system safety. Safety is of utmost concern for linemen and the general public and the minor rebuild business case provides the funding for work such as; replacement of a car-hit pole in the alley, a broken cross-arm, a burned-up transformer, and other safety related projects. In addition, if the business case is not funded, this will also affect the ability to respond to customers' needs for modifications to their electrical service. It is acknowledged some minor rebuilds left unrepaired will not result in immediate catastrophic failures to the distribution system, but over time an adverse accumulation of unrepaired assets would greatly put line workers and the general public at risk as minor asset failures begin to deteriorate within areas of the distribution system.

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.

Historical information and the continuance of tracking spend by categories will be useful in determining the effectiveness of the program and meeting its original objectives.

In 2020, Distribution Minor Rebuild transitioned to an activity-based structure that divided the business case into six general activities, which embody the major types of work performed. This division will allow for improved reporting on spend. Below is a categorical breakdown for the six general activities.

- **Customer Requested Rebuilds** – Work is initiated by an existing customer or property owner, and the costs associated with the work are typically reimbursed by the requesting party. Examples could be a customer requested reroute, overhead to underground line conversion, or customer load increase.
- **Trouble Related Rebuilds** – Emergency work required to repair damaged facilities related to non-storm and non-fire related outages. Activities include a car hit pole, car-hit padmount enclosure, copper theft, or unforeseen failed equipment that needs immediate response.
- **NESC / Operating Standard Violations** – Activities include, but are not limited to, NESC violations (not related to Joint Use clearances), secondary/service-related voltage mitigation, fusing protection mitigation, aerial trespass, and undersized equipment (transformers, regulators, etc.).
- **Asset Condition**– Activities include, but are not limited to, deteriorated wood poles, leaking transformers, condition related replacement (not outage related) of line devices and equipment.
- **Facility Upgrades/Efficiency Improvements** – Activities include, but are not limited to, small scale reconductors, small scale feeder ties, installation of new switches or sectionalizing devices, feeder balancing, installation of new regulators, reclosers, or capacitor banks, and removal of open wire secondary.
- **Facility Route / Location Modifications** – Activities include, but are not limited to, overhead to underground conversions, facility re-route, or relocation of midline devices to facilitate future maintenance and optimize sectionalization.

Figure 1 shows a chart of the estimated spend by general activity. The new general activities were implemented in January 2020.

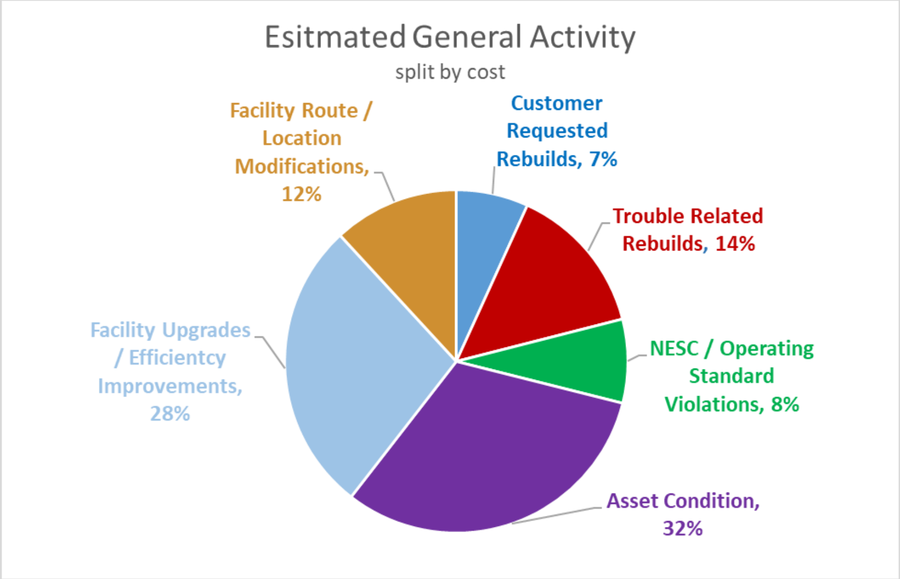


Figure 1: Estimated General Activity split by cost

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

NA

Option	Capital Cost	Start	Complete
Fund Unplanned Work (based on historical quantities)	$10,000,000	Continuous Program	
Some other Program covers the needed work.	$10,000,000	Continuous Program	
Unfunded	$0	NA	

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Historical spend was used to determine the requested amount. A steady increase in costs for unplanned minor rebuild work has occurred for several reasons. Many assets on the distribution system are past their end of life cycle and contributing to this increase. The 3-year average actual spend for minor rebuild work is $11.9MM per year. This is expected to continue for the next 5 years. Minor Rebuild spends approximately $1MM per month. Figure 3 shows the historical spend amount by year. Starting in 2020, the Joint Use spend is no longer included in the Minor Blanket Business Case as it now has its own business case.

Minor Rebuild

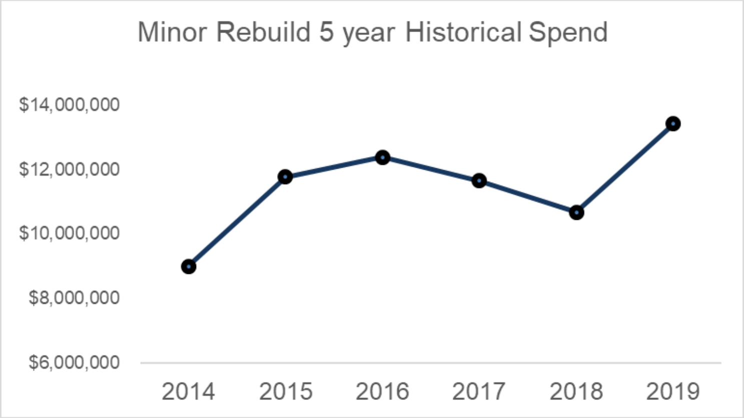


Figure 2: Minor Rebuild Historical Spend

In 2019 1,536 work orders were created with the average cost equaling $7,104, which demonstrates the work is made up of thousands of small dollars, critical non-discretionary jobs. Occasionally, larger rebuild projects such as small reconductor projects, are undertaken as a Distribution Minor Rebuild project if prioritized by the Area Operations Engineer. Only 63 (4%) of the 1,536 work orders created in 2019 were over $25,000. Those 63 work orders averaged $53,231.

Figure 2 displays a breakdown of the different types of charges that occur in the Minor Rebuild business case. The majority of charges are from specific work orders. Distribution Minor Rebuild work often consists of isolated replacement of failed asset(s) that do not lend themselves to a specific project (i.e. trouble related work), which are charges falling under craft and non-craft expenditures.

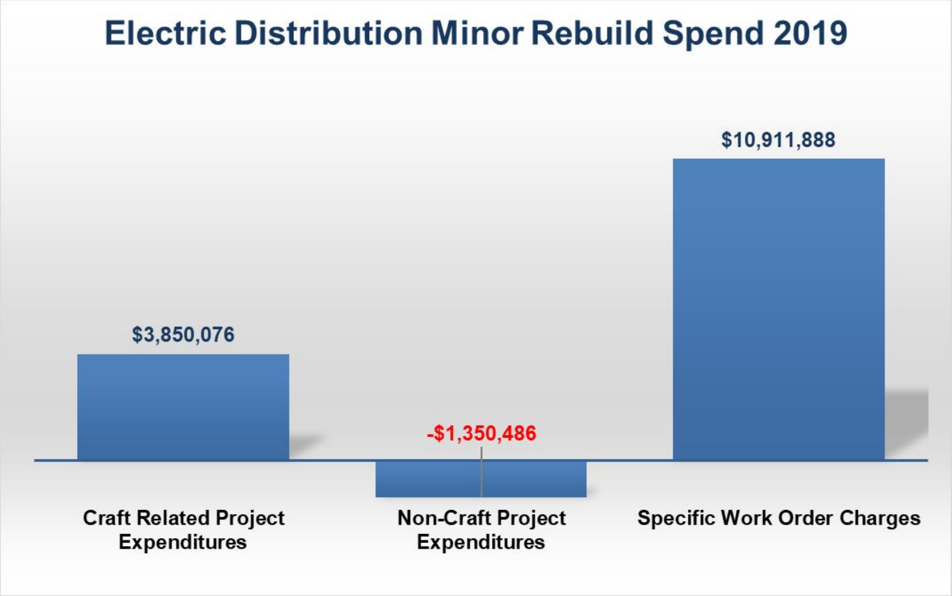


Figure 3: Types of Charges to Minor Rebuild (2019)

Minor Rebuild

The following is a brief description of each type of charge.

- **Craft Related Project Expenditures**: Craft labor (servicemen, general foremen, local rep), associated vehicle usage, trouble related work charges
- **Non-Craft Related Project Expenditures**: Non-craft labor, associated vehicle usage, contribution reimbursables (credits), and material issues/returns
- **Specific Work Order Charges**: The work order number is referenced on timesheets, material requests, invoices, and vehicle charges/loadings

The Non-Craft Project expenditures show a negative value due to customer contributions being greater than charges.

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.

Distribution Minor Rebuild is an ongoing program that focuses on keeping the distribution system in reliable condition for customers, maintaining safe conditions for the workers, provides providing responsiveness response to unplanned damages to distribution assets not related to weather events, as well as responding to small customer driven rebuilds. Throughout the entire distribution system, minor rebuilds, or replacement of asset units need to be completed to maintain system reliability and safety. Spend will continue as it has in previous years.

The work includes**;** failed asset replacements, small mandatory and compliance work, slight performance and capacity improvements, or unplanned customer requests. Occasionally, larger projects with an identified need and short timeframe for implementation are constructed under the Distribution Minor Rebuild business case. Even though the work is unplanned, Minor Rebuild work occurs regularly due to the nature of the utility business and numerous assets in the field spread over a wide geographical area.

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 Distribution Minor Rebuild business case has been in operation for several years so there will be minimal impact to other business functions and processes with funding this business case. Distribution Minor Rebuild reaches across multiple departments in Engineering and Operations. The business involves operation area engineers, local customer project coordinators, and construction technicians who work directly with customers and perform all the designs for the business. Once the minor projects are designed and ready for construction, field personnel such as a Foremen, Journeyman Linemen, Line Servicemen, Meter men, Equipment Operators execute the work.

Not funding would have a significant impact on business functions and processes as other areas would be responsible for the work and it would also impact the ability to respond to customers' needs for modifications to their electrical service.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The other alternative that was considered is not funding the business case however, the needed work will continue to occur. These costs would be covered under other business cases. The body of work within the Distribution Minor Rebuild business case consists of very small unplanned projects across the entire distribution system in response to a variety factors (customer requested, trouble related work, deteriorated pole replacements, and general rebuilds), therefore the alternatives are generally not available to analyze. Typically, as each project arises, any alternatives available for individual rebuild projects are evaluated during the design phase by the designer.

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. spend, and transfers to plant by year.

The Distribution Minor Rebuild business case is an on-going program, and assets typically go into service at the time the project (service order/ job) is completed and does not have a final cost. The program has an average annual cost around $11.5MM. The minor rebuild projects are so small in nature they almost always go into service the same day as constructed

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The Distribution Minor Rebuild business aligns with the company's focus of Our Customers, Our People, and Perform by investing in our infrastructure to achieve optimum life-cycle performance – safely, reliably and affordably. This business case provides a solution to address those small unplanned asset failures and customer driven modifications to the distribution system.

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

The Distribution Minor Rebuild business maintains flexibility for the utility to address small, unplanned asset failures and customer driven modifications to the distribution system but, excludes fixes to the system considered to be maintenance. While the work is unplanned, minor rebuilds to the distribution system occur on a regular basis every year to maintain system reliability and safety. The Distribution Minor Rebuild business case provides a solution for the utility to address those small unplanned asset failures and customer driven modifications to the distribution system. Safety is of utmost concern for linemen and the general public and the minor rebuild business case provides the funding for work. Some minor rebuilds left unrepaired may not result in an immediate catastrophic failure. Over time an adverse accumulation of unrepaired assets would greatly put line workers and the general public at risk as minor asset failures begin to deteriorate pockets of the distribution system.

The YTD spend is tracked and reviewed each month during the Electric Operations Roundtable (ORT) meetings. The ORT, reviews monthly spend and manages any additional funds requests.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders that interface with the Distribution Minor Rebuild work are the local area operations engineers, general foremen, and area construction managers.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

The Operations Roundtable (ORT) acts as the Advisory Group for this business case. The Distribution Minor Rebuild work is managed by the local area operations engineers, general foremen, and area construction managers.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance in place over the business case is set by the Operations Roundtable (ORT) group, which proposes annual budgets, monitors the incurred costs and submits any additional funds requests as needed**.**

The work done under Minor Rebuild, by way of projects, is overseen by Area Engineers. Area Engineers receive a weekly report on all active work orders under the business and managed which projects get done according to current needs and priorities. The local customer project coordinators (CPCs), who design the projects, are required to seek Area Engineer approval for projects above a $10,000 threshold before performing the work.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision making, prioritization and change requests will be documented and monitored though the Operations Roundtable (ORT).

Minor Rebuild

The undersigned acknowledge they have reviewed the ***Minor Rebuild*** 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: Amy Jones Date: 2/2/2021
Print Name: Amy Jones
Title: Asset Maintenance Business Analyst
Role: Business Case Owner

Signature: David Howell Date: 2/4/21
Print Name: David Howell
Title: Director of Operations
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Distribution System Enhancements

EXECUTIVE SUMMARY

Avista's electric distribution system is the largest part of the company's infrastructure. It consists of poles, wires, underground cable, transformers and a variety of other equipment. In addition, Avista's electric distribution system has the largest footprint of any other infrastructure within the company's service territory. This creates a unique challenge for the company. The distribution system is the largest contributor to a customer's reliability and the overall safety of the public, mostly from the sheer volume of exposure it establishes. This business case is one of several such as, Minor Rebuilds, Wood Pole Management, Grid Modernization, etc., that creates a direct customer benefit by completing projects that improve the electric distribution system's safety, performance and reliability. The jobs for this business case are identified by our area engineers for their regional areas within Washington, Idaho, and Montana and they are prioritized against each other with input from the distribution planner.

Most of the funds provided by this business case are used to complete projects that solve performance and capacity issues driven by system wide electric load growth. Other projects address power quality mitigation, reliability improvements, operational flexibility, system protection improvements, and safety enhancements. As such, the risk in not funding this business case is the inevitable decline in the overall health and operation of Avista's electric distribution system, e.g. overloading conductor to the point of failure. The ongoing nature of issues that arise within the electric distribution system coupled with the large amount of work drives the need for this business case to be funded on a yearly basis.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.1	*David James*	*Initial draft of original business case.*	*04/07/2017*	
1.2	*Cesar Godinez*	*Updated to include voltage/transformer mitigation work.*	*07/03/2019*	*Addition of voltage and transformer mitigation work identified by AMI data.*
2.0	*Cesar Godinez*	*Updated narrative and business case template.*	*07/01/2020*	*Business case refresh and name change to "Distribution System Enhancements" from "Segment Reconductor and FDR Tie."*
2.1	*Cesar Godinez*	*Minor updates.*	*01/04/2022*	*Updated "Steering Committee or Advisory Group Information" in section 3 "Monitor and Control."*

Distribution System Enhancements

GENERAL INFORMATION

Requested Spend Amount	$7,500,000
Requested Spend Time Period	*5 years (on-going)*
Requesting Organization/Department	C51 / Electric Distribution Design
Business Case Owner | Sponsor	Cesar Godinez | Josh DiLuciano
Sponsor Organization/Department	T08 / Electrical Engineering
Phase	Monitor/Control
Category	Program
Driver	Performance & Capacity

1. BUSINESS PROBLEM

Avista's electric distribution system consists of three hundred and fifty seven (357) discrete primary electric circuits encompassing over 19,000 miles of overhead conductors and underground cables. The distribution grid is managed by division or 'area engineers' and centralized distribution planning.

Load Demands on the grid are dynamic with load patterns changing as a result of many factors including weather, temperature, economic conditions, conservation efforts, and seasonal variations. Avista operates a radial distribution system using a trunk and lateral configuration (industry standard). Though many circuits are monitored at the source substation (SCADA), downstream trunk and lateral branch circuits loading are analyzed via computer simulation. At Avista, distribution analysis is performed with the **Synergi** load flow program. AMI data is also used to analyze service voltages and transformer loading. AMI data has shown system issues in the form of service voltage problems and transformer overloading. In the near future AMI load data will be exported to Synergi and used in the computer simulation.

Additionally, power quality investigation and subsequent mitigation projects are initiated by customer inquiries or analysis work. Work is also driven by reliability and safety concerns that are identified by our engineers and/or operation personnel. Operational flexibility can also drive the need to upgrade electric circuits, install switching equipment, and other infrastructure as needed.

In a manner similar to substation rebuilds, expansions, and additions that are planned for and scheduled years in advance, the distribution system also requires rebuilds, expansions, and additions. The Distribution System Enhancements Business Case allows for a methodical and planned out approach to needed feeder enhancements. Secured funding for future years allows for planning large projects in a multi-year approach, with completion of a portion of the overall project happening over a series of years. In absence of this business case, critical issues would be resolved in a reactionary and haphazard fashion, funded through the Minor Blanket, and completed outside the confines of a “big picture” plan and approach to feeder management.

Avista’s electric distribution system analysis and mitigation strategies are informed by several internal documents and data repositories. These are listed below for reference:

1. Distribution Planning Standard “500 Amp FDR” – internal document that defines the performance criteria and limits for both urban FDR tie systems and rural pure radial circuits. This document is maintained by Distribution System Planning (Damon Fisher).
2. FDR Status Report – distribution engineering publishes an annual report indicating peak circuit demand by season, reliability outage statistics, circuit health check, and other logistic information.
3. Distribution Standards – distribution engineering maintains construction standards for both overhead and underground primary circuits. It also maintains standards for all electrical material and apparatus.
4. PI Database – operating data retrieved by either the SCADA or DMS system is stored in the PI historian. This allows direct access by engineers and planners to help inform both operating and design strategies. (Distribution Operations)
5. Distribution FDR Management Plan – a design guide to assist the CPC/Engineer when making decisions related to reinforcements or reconstruction of distribution assets (Asset Management).
6. Feeder Automation Strategy – a design guide to assist the CPC/Engineer when making decisions involving automated devices (Distribution Engineering).
7. Synergi Computer Program – the load flow program derives topology information from Avista’s GIS system. Updates to the Synergi database are performed by Distribution Planning.
8. SCADA Variable Limit (SVL) – Avista uses temperature compensated program to monitor conductors, cables, and series connected major equipment (e.g. transformers, breakers, switches, regulators, and etc.). This system is deployed on Avista’s EMS/SCADA system. The program is SME supported by Substation Engineering.
9. AMI Data – AMI service voltage data is used to identify services that are out of compliance with the ANSI C84.1 standard of +/- 5% of 120 volts. AMI service load data is used to identify transformers that are overloaded according to the standards set by distribution engineering.

A typical distribution circuit is illustrated on the next page. Similar to municipal water systems, grid capacity decreases with distance away from the source substation. This leads to system ‘constraints’ as loads are added to the system through direct customer action or load shifting between circuits (Avista).

Distribution System Enhancements

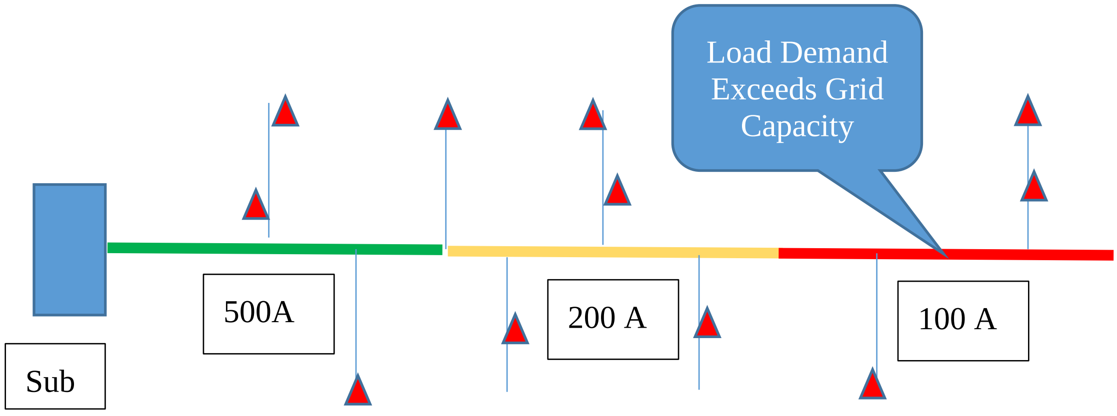


Illustration of Distribution Grid Capacity Constraint
Avista's Distribution System contains over 75 different wires and cables

2020 Avista Standard OH Primary Conductors

556 All-Aluminum (AAC) – 601 Amps (main trunk, urban)
336 All-Aluminum (AAC) – 442 Amps (main trunk, rural)
2/0 Aluminum Conductor, Steel Reinforced (ACSR) – 238 Amps (gen purposes, rural)
#4 Aluminum Conductor, Steel Reinforced (ACSR) – 119 Amps (lateral circuit)

Legacy Conductors

2/0-3/0 Copper – 319-369 Amps (main trunk)
#2 Copper – 197 Amps (main trunk)
#6 Copper - 110 Amps (lateral circuit)

Avista's distribution grid contain over 1,000 miles of conductor equivalent or smaller than #6 Copper.

Distribution System Enhancements

Option	Description	Consequence
Do-Nothing	No Action to mitigate thermal overloads, power quality issues, reliability and safety issues.	Conductor will 'sag' down beyond design limits and contact joint-use telecom circuits or violate NESC prescribed limits. In extreme situations, conductor failure will occur. Service quality will degrade below acceptable levels and customer outages will increase. System enhancements (if they occur at all) will be done in a "scattered" approach and not guided by engineered plans and solutions.
Select DSM treatment	Target homes and businesses with demand side management solutions to effect peak load demand reduction.	This option would be a viable, however, State Commissions do not allow DSM treatment in localized areas.
Load Shifting	FDR Tie	This action is represented in the Distribution System Enhancements program. By extending lines to adjacent circuits, load can be shifted to underutilized circuits and mitigate overloads. This action requires capital investment.
Capacity Increase	Reconductor overloaded 'segments' to increase line capacity, mitigate identified low voltage issues, and correct system protection issue. Install voltage regulators to mitigate feeder level low voltage issues. Replace Transformers (or install additional transformers) to mitigate overloaded transformers and service voltage issues.	All electric components are thermally limited. Reconductoring is the most direct approach to mitigating overloaded circuits and low voltage issues.
System Enhancements	Mitigate power quality issues, as well as, reliability and safety issues. Add operational flexibility to the electric distribution system. Expand distribution automation by adding targeted "smart" devices.	Accomplishing this type of work ensures that our electric distribution system is operated efficiently, reliably, and safe.

Distribution System Enhancements

Recommendation:

1. Do Nothing is unacceptable. Violates NESC/WAC regulations and industry standards. It also represents an unacceptable level of risk to public safety and infrastructure.
2. Targeted DSM is not allowed.
3. FDR Tie – represented in the program (indirect solution).
4. Segment Reconductor – represented in the program (direct solution).
5. System Enhancements – represented in the program.

Projects listed in the current 5-year "Distribution System Enhancements" program are summarized on the Distribution Engineering SharePoint site. The following is a summary of those projects listings as of June 2, 2020.

https://sp2016.corp.com/sites/sp/enso/dist/_layouts/15/start.aspx

Region	2021	2022	2023	2024	2025
Spokane	2,946,400	2,946,400	2,946,400	2,946,400	2,946,400
East	2,142,900	2,142,900	2,142,900	2,142,900	2,142,900
South	1,339,300	1,339,300	1,339,300	1,339,300	1,339,300
Big Bend	1,071,400	1,071,400	1,071,400	1,071,400	1,071,400
Total	**7,500,000**	**7,500,000**	**7,500,000**	**7,500,000**	**7,500,000**

One of the planning objectives is to levelize the resource demands and avoid significant upswings or downturns in crew resource forecasting. Distribution Engineering works closely with the Operating Divisions and Asset Maintenance to develop a resource balanced work plan and maximize the effectiveness of Avista craft resources. In addition, reductions in funding of this business case typically result in increase spend in our Minor Blanket business case.

Distribution assets are fixed resources and therefore, project alternatives are generally dominated by supply side solutions. Operating limitations are codified in Avista internal standards (as listed) but derived through industry and regulatory policies including: Washington Administrative Code (WAC), National Electric Safety Code (NESC), National Electric Code (NEC), and IEEE/ANSI standards & manufacturer recommendations specific to equipment ratings and operating limits.

Steering Committee or Advisory Group Information

Distribution Area/Operations Engineers and Distribution System Planning.

Tim Figart & Jon Gilrein – Spokane and Deer Park

Marshall Law & Marc Lippincott – East Region (CDA, Kellogg, St. Maries, Sandpoint)

Dan Knutson – Othello, Davenport

Tyler Dornquast – Colville

Chris Dux – South Region (Pullman, Clarkston, Grangeville)

Damon Fisher – Distribution System Planning

Cesar Godinez – Distribution Engineering Manager

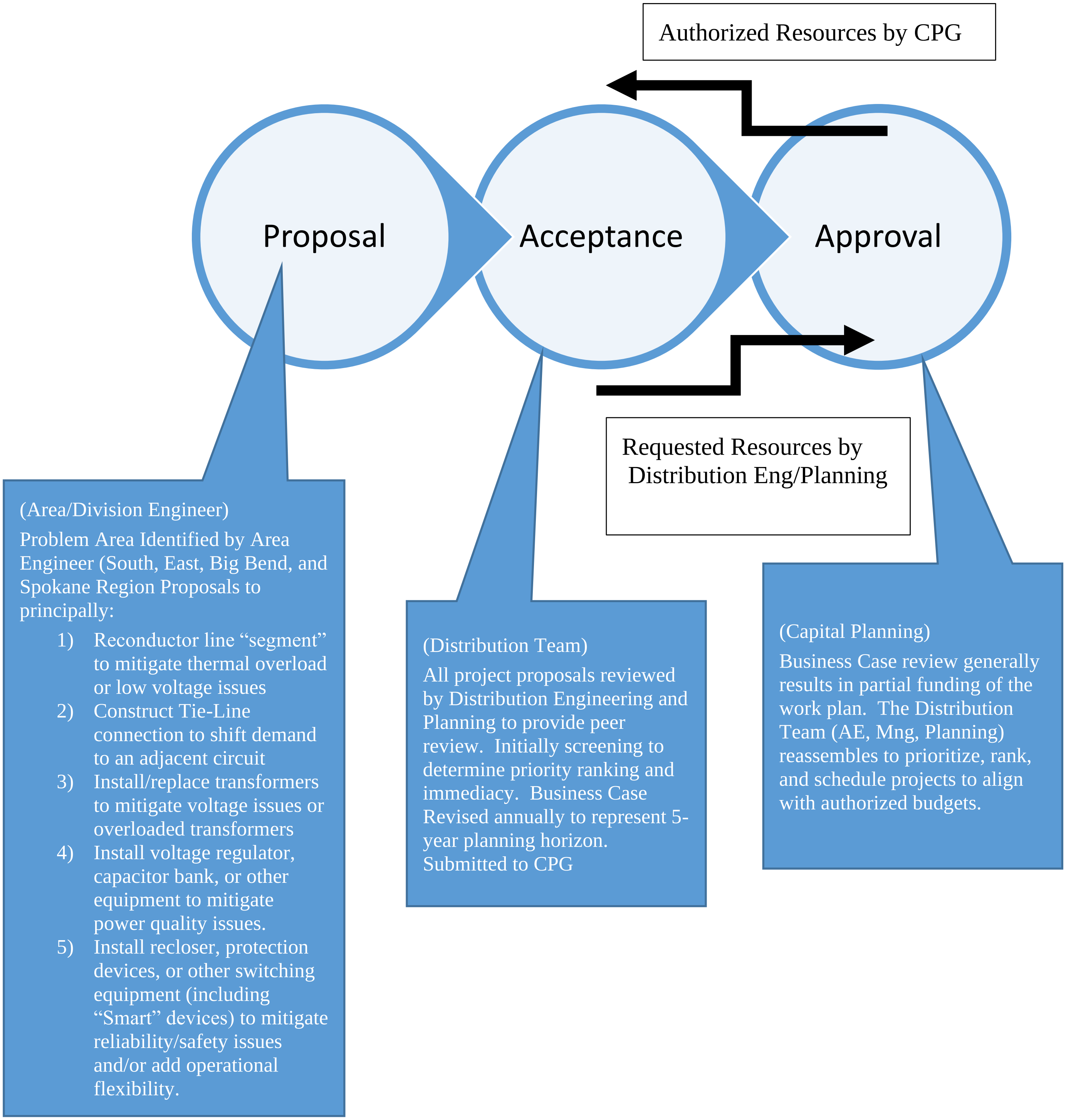
The steering committee meets monthly to review projects and construction processes and discuss near term operating conditions. The team also meets quarterly to focus attention and resources on the system planning needs for grid capacity, service revisions, and substation capacity.

Decision Making Process

The decision model is represented by individual ‘proposals’ coupled with joint review and acceptance by distribution engineering and distribution system planning. The project ‘proposals’ typically consist of a Project Requirement Diagram (PRD) that outlines the scope of the project and includes supporting calculations and documentation. The program’s business case is modified annually to reflect the 5-year work plan. The Capital Planning Group then reviews all of the submitted business cases and prioritizes and allocates resources across the organization. *Distribution infrastructure is not part of the “Engineering Roundtable” with the exception of distribution substations.*

The Distribution System Enhancements business case decision model is illustrated on the next page.

Distribution System Enhancements



Authorized Resources by CPG

Proposal

Acceptance

Approval

Requested Resources by Distribution Eng/Planning

(Area/Division Engineer)

Problem Area Identified by Area Engineer (South, East, Big Bend, and Spokane Region Proposals to principally:

1) Reconductor line “segment” to mitigate thermal overload or low voltage issues
2) Construct Tie-Line connection to shift demand to an adjacent circuit
3) Install/replace transformers to mitigate voltage issues or overloaded transformers
4) Install voltage regulator, capacitor bank, or other equipment to mitigate power quality issues.
5) Install recloser, protection devices, or other switching equipment (including “Smart” devices) to mitigate reliability/safety issues and/or add operational flexibility.

(Distribution Team)

All project proposals reviewed by Distribution Engineering and Planning to provide peer review. Initially screening to determine priority ranking and immediacy. Business Case Revised annually to represent 5-year planning horizon. Submitted to CPG

(Capital Planning)

Business Case review generally results in partial funding of the work plan. The Distribution Team (AE, Mng, Planning) reassembles to prioritize, rank, and schedule projects to align with authorized budgets.

Distribution System Enhancements

The undersigned acknowledge they have reviewed the *Distribution System Enhancements* 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: Date: 1/4/2022
Print Name: Cesar Godinez
Title: Distribution Engineering Manager
Role: Business Case Owner

Signature: Date: 1/6/2022
Print Name: Josh DiLuciano
Title: Director of Electrical Engineering
Role: Business Case Sponsor

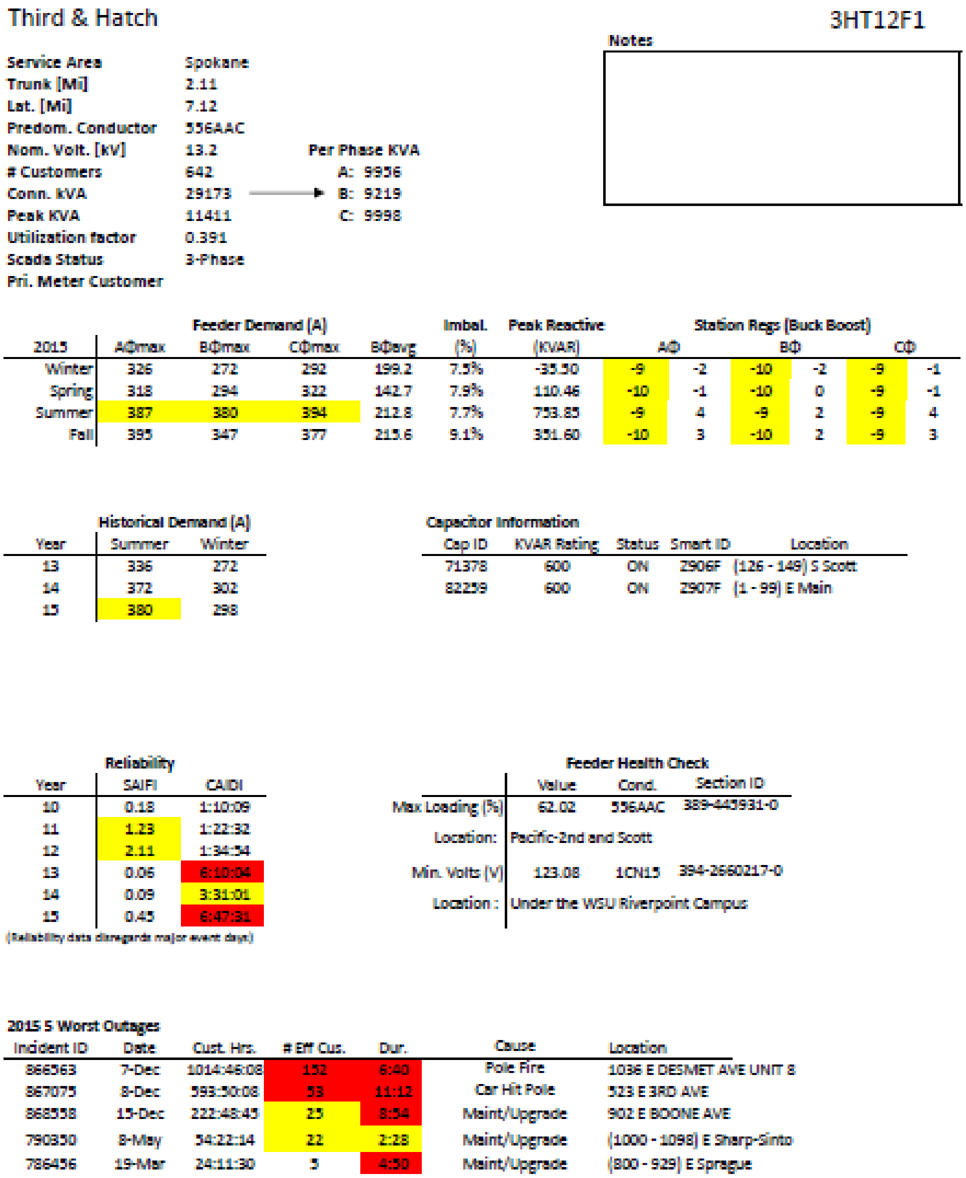
Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Distribution System Enhancements

EXAMPLES SHOWN FOR ILLUSTRATION:

FDR Status Report (provides baseline circuit performance and logistics information) Warning Level (yellow highlight),



Third & Hatch

3HT12F1

Service Area	Spokane		
Trunk [Mi]	2.11		
Lat. [Mi]	7.12		
Predom. Conductor	556AAC		
Nom. Volt. [kV]	13.2	**Per Phase KVA**	
# Customers	642	A:	9956
Conn. kVA	29173	B:	9219
Peak KVA	11411	C:	9998
Utilization factor	0.391		
Scada Status	3-Phase		
Pri. Meter Customer			

Notes

	Feeder Demand (A)				Imbal.	Peak Reactive	Station Regs (Buck Boost)					
2015	AΦmax	BΦmax	CΦmax	BΦavg	(%)	(KVAR)	AΦ		BΦ		CΦ	
Winter	326	272	292	199.2	7.5%	-35.50	-9	-2	-10	-2	-9	-1
Spring	318	294	322	142.7	7.9%	110.46	-10	-1	-10	0	-9	-1
Summer	387	380	394	212.8	7.7%	753.85	-9	4	-9	2	-9	4
Fall	395	347	377	215.6	9.1%	351.60	-10	3	-10	2	-9	3

	Historical Demand (A)	
Year	Summer	Winter
13	336	272
14	372	302
15	380	298

Capacitor Information

Cap ID	KVAR Rating	Status	Smart ID	Location
71378	600	ON	2906F	(126 - 149) S Scott
82259	600	ON	2907F	(1 - 99) E Main

	Reliability	
Year	SAIFI	CAIDI
10	0.18	1:10:09
11	1.23	1:22:32
12	2.11	1:34:54
13	0.06	6:10:04
14	0.09	3:31:01
15	0.45	6:47:31

(Reliability data disregards major event days)

Feeder Health Check

	Value	Cond.	Section ID
Max Loading (%)	62.02	556AAC	389-445931-0
Location:	Pacific-2nd and Scott		
Min. Volts (V)	123.08	1CN15	394-2660217-0
Location :	Under the WSU Riverpoint Campus		

2015 5 Worst Outages

Incident ID	Date	Cust. Hrs.	# Eff Cus.	Dur.	Cause	Location
866363	7-Dec	1014:46:08	152	6:40	Pole Fire	1036 E DESMET AVE UNIT 8
867075	8-Dec	593:50:08	53	11:12	Car Hit Pole	523 E 3RD AVE
868558	15-Dec	222:48:45	25	8:54	Maint/Upgrade	902 E BOONE AVE
790350	8-May	54:22:14	22	2:28	Maint/Upgrade	(1000 - 1098) E Sharp-Sinto
786456	19-Mar	24:11:30	5	4:50	Maint/Upgrade	(800 - 929) E Sprague

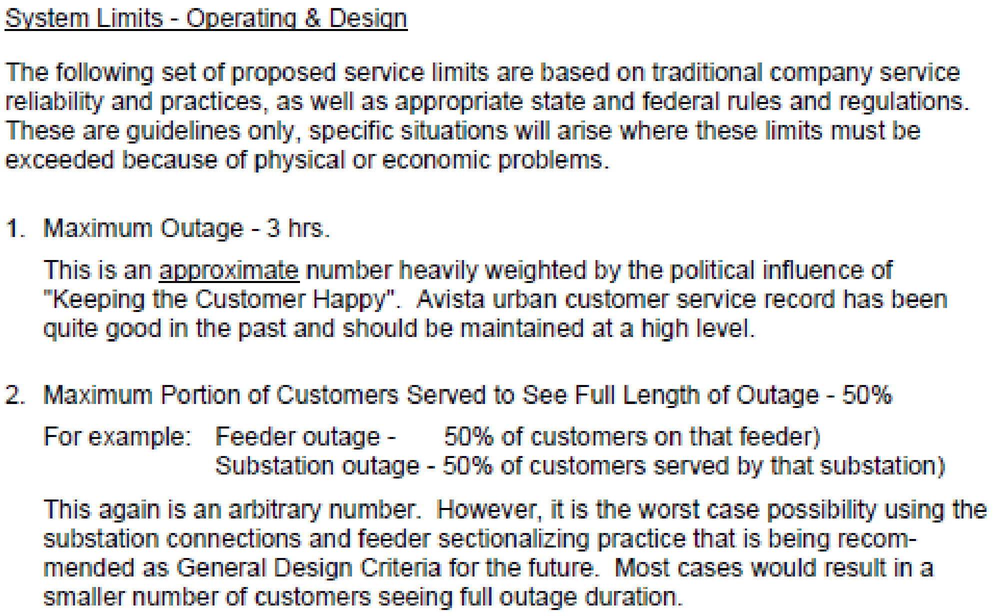
Exh. HLR-2

Distribution System Enhancements

Distribution “500 Amp” Plan (System Planning)

Company standard for the operation and load service planning associated with Avista’s electric distribution grid.

Key elements-- Urban “FRD Tie” system. Requires that reserve capacity margins be maintained so that adjacent circuits can restore service to customers in the event of a planned or forced outage. In summary, no urban circuit should be loaded above its 67% capacity limit.



System Limits - Operating & Design

The following set of proposed service limits are based on traditional company service reliability and practices, as well as appropriate state and federal rules and regulations. These are guidelines only, specific situations will arise where these limits must be exceeded because of physical or economic problems.

1. Maximum Outage - 3 hrs.

   This is an approximate number heavily weighted by the political influence of "Keeping the Customer Happy". Avista urban customer service record has been quite good in the past and should be maintained at a high level.

2. Maximum Portion of Customers Served to See Full Length of Outage - 50%

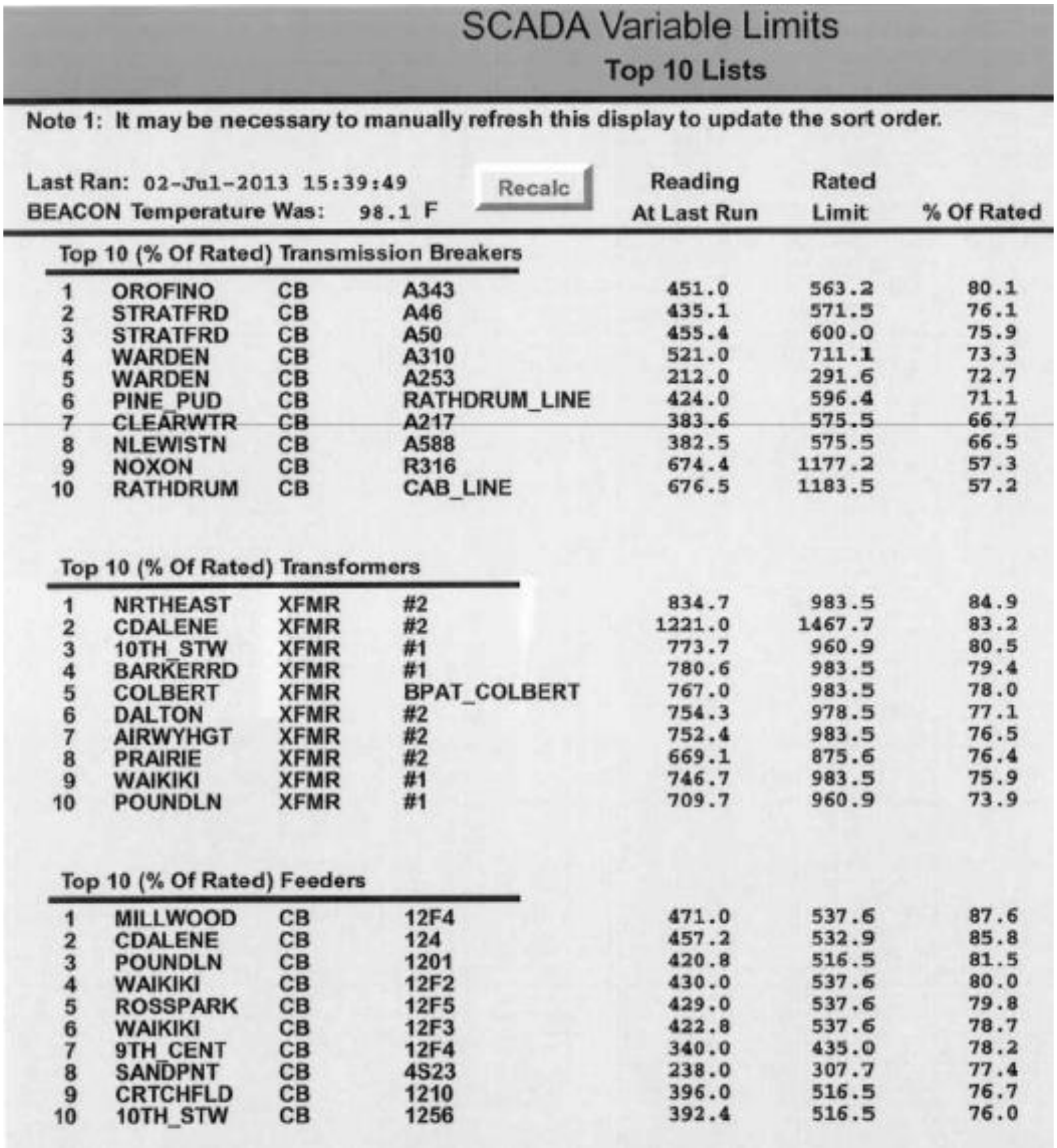
   For example: Feeder outage - 50% of customers on that feeder)
   Substation outage - 50% of customers served by that substation)

   This again is an arbitrary number. However, it is the worst case possibility using the substation connections and feeder sectionalizing practice that is being recommended as General Design Criteria for the future. Most cases would result in a smaller number of customers seeing full outage duration.

Excerpt from “500 Amp” Plan. Source: Distribution SharePoint (3/15/17)

Distribution System Enhancements

Avista's SCADA monitoring system incorporates a temperature compensated thermal ampacity rating system known internally as SVL (Scada Variable Limit). SVL has been in use since 1993. The following indicates a summary screen indicating the top ten most heavily loaded (by % capacity) transmission lines, substation power transformers, and distribution circuits. This screen is continuously monitored by System Operators but also used by Area Engineers to capture data during peak load conditions. It provides additional data to aid with project planning for the distribution system enhancements program.



SCADA Variable Limits

Top 10 Lists

Note 1: It may be necessary to manually refresh this display to update the sort order.

Last Run: 02-Jul-2013 15:39:49
BEACON Temperature Was: 98.1 F

Top 10 (% Of Rated) Transmission Breakers

				Reading At Last Run	Rated Limit	% Of Rated
1	OROFINO	CB	A343	451.0	563.2	80.1
2	STRATFRD	CB	A46	435.1	571.5	76.1
3	STRATFRD	CB	A50	455.4	600.0	75.9
4	WARDEN	CB	A310	521.0	711.1	73.3
5	WARDEN	CB	A253	212.0	291.6	72.7
6	PINE_PUD	CB	RATHDRUM_LINE	424.0	596.4	71.1
7	CLEARWTR	CB	A217	383.6	575.5	66.7
8	NLEWISTN	CB	A588	382.5	575.5	66.5
9	NOXON	CB	R316	674.4	1177.2	57.3
10	RATHDRUM	CB	CAB_LINE	676.5	1183.5	57.2

Top 10 (% Of Rated) Transformers

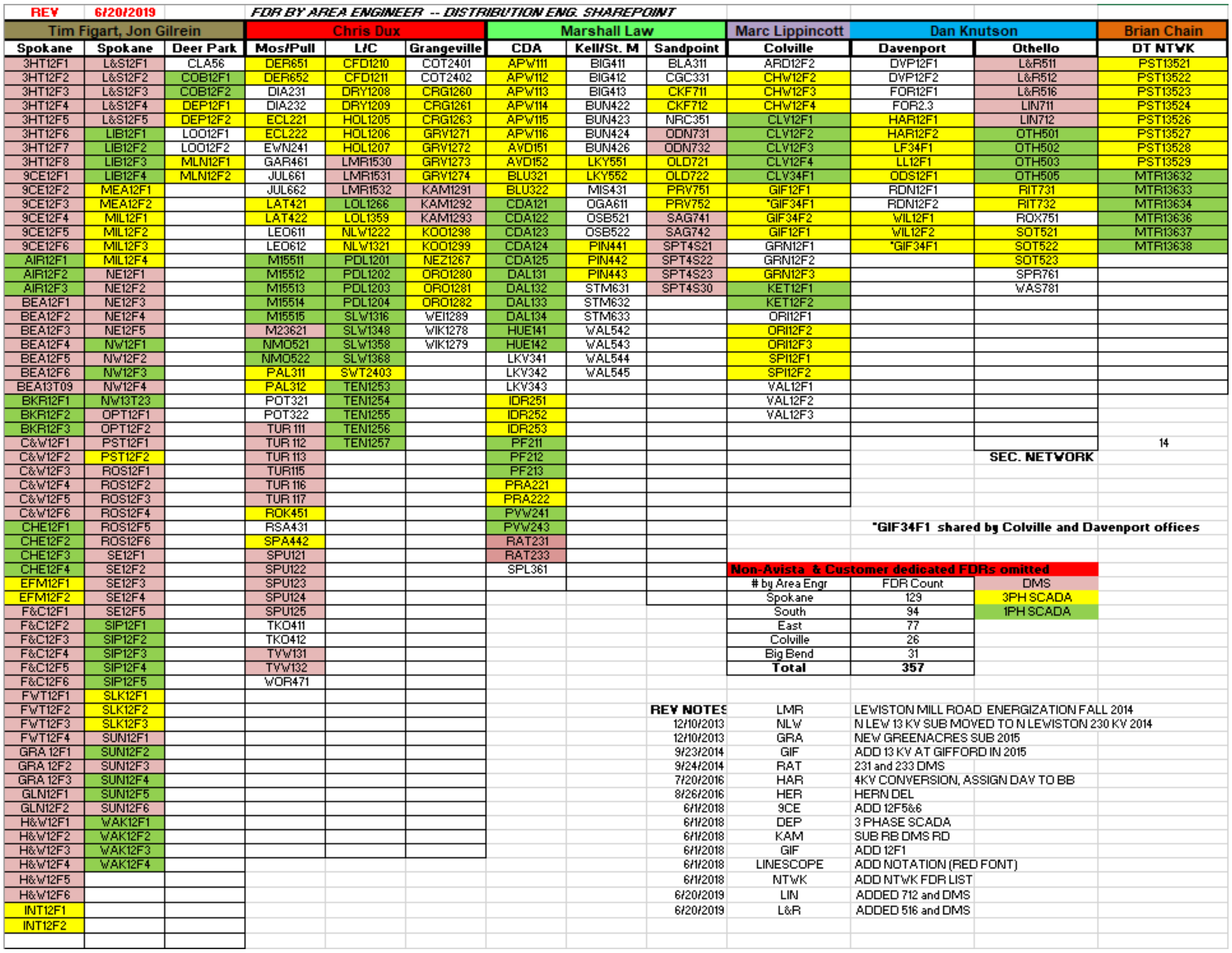
				Reading At Last Run	Rated Limit	% Of Rated
1	NRTHEAST	XFMR	#2	834.7	983.5	84.9
2	CDALENE	XFMR	#2	1221.0	1467.7	83.2
3	10TH_STW	XFMR	#1	773.7	960.9	80.5
4	BARKERRD	XFMR	#1	780.6	983.5	79.4
5	COLBERT	XFMR	BPAT_COLBERT	767.0	983.5	78.0
6	DALTON	XFMR	#2	754.3	978.5	77.1
7	AIRWYHGT	XFMR	#2	752.4	983.5	76.5
8	PRAIRIE	XFMR	#2	669.1	875.6	76.4
9	WAIKIKI	XFMR	#1	746.7	983.5	75.9
10	POUNDLN	XFMR	#1	709.7	960.9	73.9

Top 10 (% Of Rated) Feeders

				Reading At Last Run	Rated Limit	% Of Rated
1	MILLWOOD	CB	12F4	471.0	537.6	87.6
2	CDALENE	CB	124	457.2	532.9	85.8
3	POUNDLN	CB	1201	420.8	516.5	81.5
4	WAIKIKI	CB	12F2	430.0	537.6	80.0
5	ROSSPARK	CB	12F5	429.0	537.6	79.8
6	WAIKIKI	CB	12F3	422.8	537.6	78.7
7	9TH_CENT	CB	12F4	340.0	435.0	78.2
8	SANDPNT	CB	4S23	238.0	307.7	77.4
9	CRTCHFLD	CB	1210	396.0	516.5	76.7
10	10TH_STW	CB	1256	392.4	516.5	76.0

Distribution System Enhancements

FDR by Area. Shown only to illustrate the scale of the effort to monitor our distribution system.



REV 6/20/2019 *FDR BY AREA ENGINEER -- DISTRIBUTION ENG. SHAREPOINT*

Tim Figart, Jon Gilrein			Chris Dux			Marshall Law			Marc Lippincott	Dan Knutson		Brian Chain
Spokane	**Spokane**	**Deer Park**	**Mos/Pull**	**L/C**	**Grangeville**	**CDA**	**Kell/St. M**	**Sandpoint**	**Colville**	**Davenport**	**Othello**	**DT NTWK**
3HT12F1	L&S12F1	CLA56	DER651	CFD1210	COT2401	APW111	BIG411	BLA311	ARD12F2	DVP12F1	L&R511	PST13521
3HT12F2	L&S12F2	COB12F1	DER652	CFD1211	COT2402	APW112	BIG412	CGC331	CHW12F2	DVP12F2	L&R512	PST13522
3HT12F3	L&S12F3	COB12F2	DIA231	DRY1208	CRG1260	APW113	BIG413	CKF711	CHW12F3	FOR12F1	L&R516	PST13523
3HT12F4	L&S12F4	DEP12F1	DIA232	DRY1209	CRG1261	APW114	BUN422	CKF712	CHW12F4	FOR2.3	LIN711	PST13524
3HT12F5	L&S12F5	DEP12F2	ECL221	HOL1205	CRG1263	APW115	BUN423	NRC351	CLV12F1	HAR12F1	LIN712	PST13526
3HT12F6	LIB12F1	LOO12F1	ECL222	HOL1206	GRV1271	APW116	BUN424	ODN731	CLV12F2	HAR12F2	OTH501	PST13527
3HT12F7	LIB12F2	LOO12F2	EWN241	HOL1207	GRV1272	AVD151	BUN426	ODN732	CLV12F3	LF34F1	OTH502	PST13528
3HT12F8	LIB12F3	MLN12F1	GAR461	LMR1530	GRV1273	AVD152	LKY551	OLD721	CLV12F4	LL12F1	OTH503	PST13529
9CE12F1	LIB12F4	MLN12F2	JUL661	LMR1531	GRV1274	BLU321	LKY552	OLD722	CLV34F1	ODS12F1	OTH505	MTR13632
9CE12F2	MEA12F1		JUL662	LMR1532	KAM1291	BLU322	MIS431	PRV751	GIF12F1	RDN12F1	RIT731	MTR13633
9CE12F3	MEA12F2		LAT421	LOL1266	KAM1292	CDA121	OGA611	PRV752	'GIF34F1	RDN12F2	RIT732	MTR13634
9CE12F4	MIL12F1		LAT422	LOL1359	KAM1293	CDA122	OSB521	SAG741	GIF34F2	WIL12F1	ROX751	MTR13636
9CE12F5	MIL12F2		LEO611	NLW1222	KOO1298	CDA123	OSB522	SAG742	GIF12F1	WIL12F2	SOT521	MTR13637
9CE12F6	MIL12F3		LEO612	NLW1321	KOO1299	CDA124	PIN441	SPT4S21	GRN12F1	'GIF34F1	SOT522	MTR13638
AIR12F1	MIL12F4		M15511	PDL1201	NEZ1267	CDA125	PIN442	SPT4S22	GRN12F2		SOT523	
AIR12F2	NE12F1		M15512	PDL1202	ORO1280	DAL131	PIN443	SPT4S23	GRN12F3		SPR761	
AIR12F3	NE12F2		M15513	PDL1203	ORO1281	DAL132	STM631	SPT4S30	KET12F1		WAS781	
BEA12F1	NE12F3		M15514	PDL1204	ORO1282	DAL133	STM632		KET12F2			
BEA12F2	NE12F4		M15515	SLW1316	WEI1289	DAL134	STM633		ORI12F1			
BEA12F3	NE12F5		M23621	SLW1348	WIK1278	HUE141	WAL542		ORI12F2			
BEA12F4	NW12F1		NMO521	SLW1358	WIK1279	HUE142	WAL543		ORI12F3			
BEA12F5	NW12F2		NMO522	SLW1368		LKV341	WAL544		SPI12F1			
BEA12F6	NW12F3		PAL311	SWT2403		LKV342	WAL545		SPI12F2			
BEA13T09	NW12F4		PAL312	TEN1253		LKV343			VAL12F1			
BKR12F1	NW13T23		POT321	TEN1254		IDR251			VAL12F2			
BKR12F2	OPT12F1		POT322	TEN1255		IDR252			VAL12F3			
BKR12F3	OPT12F2		TUR 111	TEN1256		IDR253						
C&W12F1	PST12F1		TUR 112	TEN1257		PF211						14
C&W12F2	PST12F2		TUR 113			PF212					**SEC. NETWORK**	
C&W12F3	ROS12F1		TUR115			PF213						
C&W12F4	ROS12F2		TUR 116			PRA221						
C&W12F5	ROS12F3		TUR 117			PRA222						
C&W12F6	ROS12F4		ROK451			PVW241						
CHE12F1	ROS12F5		RSA431			PVW243						
CHE12F2	ROS12F6		SPA442			RAT231						
CHE12F3	SE12F1		SPU121			RAT233						
CHE12F4	SE12F2		SPU122			SPL361						
EFM12F1	SE12F3		SPU123									
EFM12F2	SE12F4		SPU124									
F&C12F1	SE12F5		SPU125									
F&C12F2	SIP12F1		TKO411									
F&C12F3	SIP12F2		TKO412									
F&C12F4	SIP12F3		TVW131									
F&C12F5	SIP12F4		TVW132									
F&C12F6	SIP12F5		WOR471									
FWT12F1	SLK12F1											
FWT12F2	SLK12F2											
FWT12F3	SLK12F3											
FWT12F4	SUN12F1											
GRA 12F1	SUN12F2											
GRA 12F2	SUN12F3											
GRA 12F3	SUN12F4											
GLN12F1	SUN12F5											
GLN12F2	SUN12F6											
H&W12F1	WAK12F1											
H&W12F2	WAK12F2											
H&W12F3	WAK12F3											
H&W12F4	WAK12F4											
H&W12F5												
H&W12F6												
INT12F1												
INT12F2												

'GIF34F1 shared by Colville and Davenport offices

Non-Avista & Customer dedicated FDRs omitted

# by Area Engr	FDR Count	
Spokane	129	3PH SCADA
South	94	1PH SCADA
East	77	
Colville	26	
Big Bend	31	
Total	**357**	

DMS

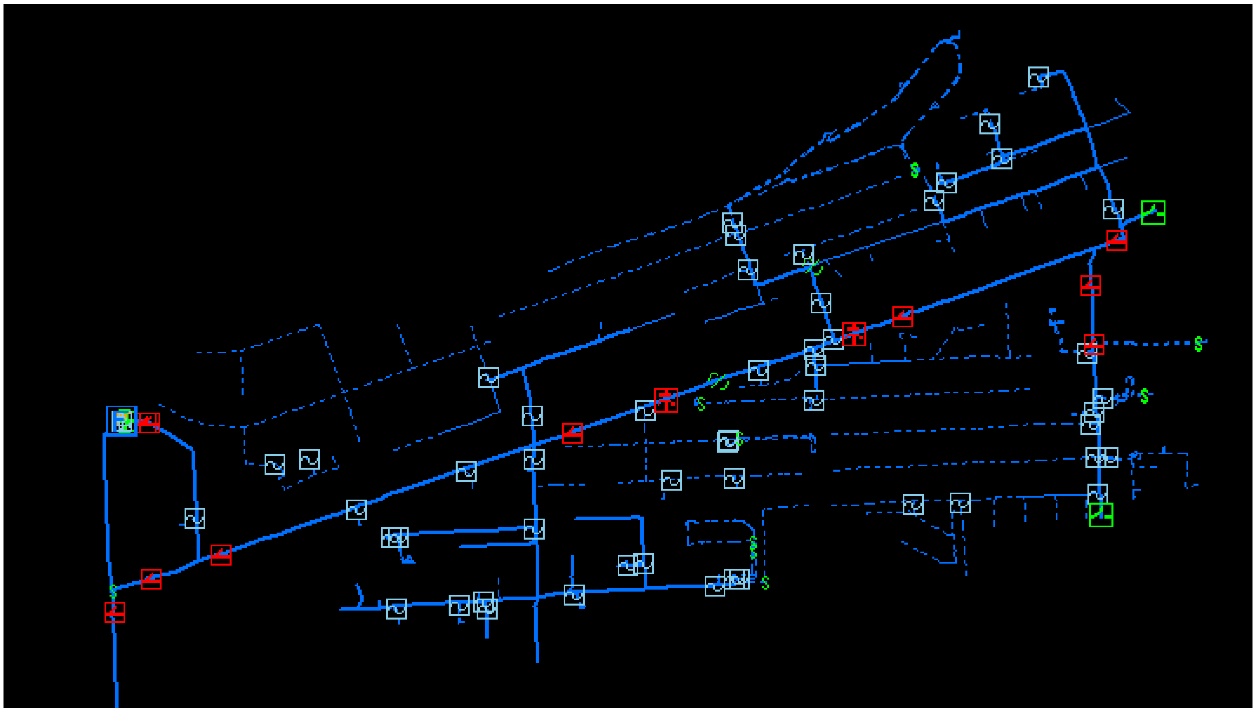
REV NOTES	LMR	LEWISTON MILL ROAD ENERGIZATION FALL 2014
12/10/2013	NLW	N LEW 13 KV SUB MOVED TO N LEWISTON 230 KV 2014
12/10/2013	GRA	NEW GREENACRES SUB 2015
9/23/2014	GIF	ADD 13 KV AT GIFFORD IN 2015
9/24/2014	RAT	231 and 233 DMS
7/20/2016	HAR	4KV CONVERSION, ASSIGN DAV TO BB
8/26/2016	HER	HERN DEL
6/1/2018	9CE	ADD 12F5&6
6/1/2018	DEP	3 PHASE SCADA
6/1/2018	KAM	SUB RB DMS RD
6/1/2018	GIF	ADD 12F1
6/1/2018	LINESCOPE	ADD NOTATION (RED FONT)
6/1/2018	NTWK	ADD NTWK FDR LIST
6/20/2019	LIN	ADDED 712 and DMS
6/20/2019	L&R	ADDED 516 and DMS

Distribution System Enhancements

Synergi Computer Modeling (Millwood 12F4 screen shot)

Computer simulation is the primary tool used to identify and develop strategies to mitigate a thermal overload condition. Note, that Avista's electric distribution system has been developed over the full course of the Company's operating history and infrastructure installed near the turn of the century (1900) is still in-service. Though current Avista construction standards limit the number of overhead primary wires to four (4): #4 ASCR, 2/0 ACSR, 336 AAC, 556 AAC; Avista maintains a fleet of seventy five (75) different primary wires and cables. Many are no longer available commercially and we maintain 'hand coils' salvaged from project work in order to effect maintenance repairs on those conductor segments. We ceased to install overhead copper conductors in the 1950's though today, thousands of miles of #6A, #6CW, and other copper conductors remain in service.

Synergi Computer System: Millwood 12F4 Circuit



Distribution Transformer Change Out Program

EXECUTIVE SUMMARY

The Transformer Change Out Program (TCOP) was originally implemented in 2011. The Program is focused on removing or replacing transformers containing, or potentially containing, Polychlorinated Biphenyls (PCB) oil. In 2020, there were 284 targeted transformers remaining. This impacts customers in WA and ID.

In 2020, the program was funded at $541,000, for 2021 we are requesting $500,000. The benefit to customers is decreasing environmental risk. This program is anticipated to be completed by the end of 2021. If not funded or if deferred, it does increase the risk of environmental hazards (i.e. oil spill).

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Initial draft for 2020 business case refresh*	*6/30/2020*	
1.0				
1.1				
2.0				

Distribution Transformer Change Out Program

GENERAL INFORMATION

Requested Spend Amount	$500,000
Requested Spend Time Period	*1 Year (2021)*
Requesting Organization/Department	Asset Maintenance
Business Case Owner | Sponsor	Amy Jones | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Transformer Change Out Program (TCOP) was originally implemented in 2011. The Program has focused on eliminating transformers containing or potentially containing Polychlorinated Biphenyls (PCB) oil. The areas initially targeted were near the Spokane and Pend Oreille River watersheds and has since moved to all transformers containing PCBs. These transformers have specific work plans for removing them from the system. At the start of 2020, there were 284 targeted transformers remaining and scheduled to be replaced by the end of 2020. However, over the past two (2) years, the carryover from the previous year has been approximately 50%. For 2021, an estimated carryover-total of 150 targeted transformers is expected.

BACKGROUND:

PCBs and PCB wastes are regulated by both the Washington Department of Ecology (Ecology), through the Dangerous Waste Regulations, Chapter 173-303 WAC, and by the U.S. Environmental Protection Agency (EPA) under 40 CFR Part 761, the Toxic Substances Control Act (TSCA). The transformers to be removed early in the program are those that are most likely to have PCB-containing oil and their replacement will reduce the risk of PCB-containing oil spills which are a public safety, environmental, and a public relations concern.

On April 10, 2010, the EPA had issued an Advanced Notice of Proposed Rulemaking (ANPR) on new PCB regulations. Washington State Department of Ecology created an “urban waters initiative” to investigate persistent and bio-accumulative toxins; this initiative included the Spokane River watershed. The Spokane River is listed on the Clean Water Act “impaired” list for PCB contamination. The City of Spokane began a storm water study to find and reduce sources of PCBs in its storm water system. In addition, PCB cleanup is very difficult in any environment and nearly impossible in aqueous environments. These and other efforts reflect how important it is to keep PCBs from entering the environment. As a result, Avista is determined to aggressively remove PCBs from its electrical distribution system in a disciplined manner.

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 TCOP is Asset Condition. However, by removing these targeted transformers, the environmental and public safety risks associated with these transformers will also be addressed.

Customer Benefit: Avista customers will be impacted by this program positively through safe equipment.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Currently there are 264 targeted transformers remaining (as of May 30, 2020). There are environmental risks associated with these transformers (large volume transformer oil spill, hazardous waste cleanup, moderate to low volume or level of PCBs, impacts to waterways, repeated or moderate air emission exceedance). PCB cleanup is very difficult in any environment and nearly impossible in aqueous environments. These and other efforts reflect how important it is to keep PCBs from entering the environment. In addition, environmental spill cleanup for PCBs can be costly. If not funded or deferred, the risk is low due to the small number of remaining transformers.

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.

This Program has been successful throughout previously funded years. It is anticipated that all transformers will be replaced by the end of 2021.

Metrics that will be used to determine successful delivery throughout the program year include:
- Planned vs replaced transformers
- Count of remaining transformers
- Budget to actual spend

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

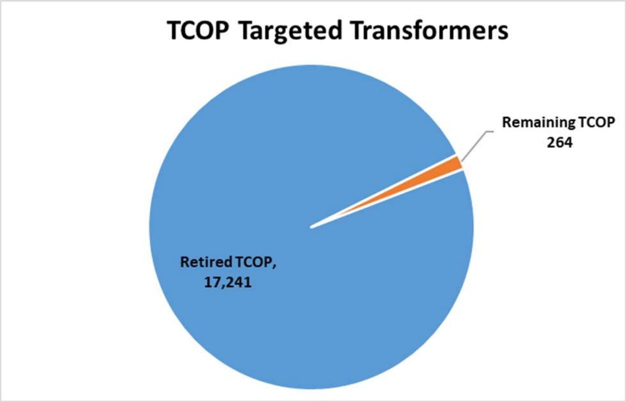
References:

- “Distribution Transformer PCBs” report, February 2010
- Electric Distribution System, 2016 Asset Management Plan

Distribution Transformer Change Out Program

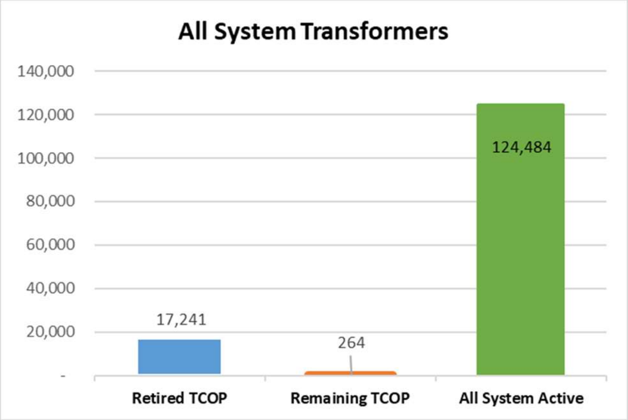
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

17,241 transformers have been replaced since the start of the program. As of 5/30/2020, there are 264 pending replacement due to PCB containing oils. We anticipate 150 remaining at the end of 2020.



This program has been successful in meeting its objective.

Remaining TCOP transformers are included in the All System Active count. The remaining targeted transformers represent .02% of all active transformers. All targeted transformers (retired and remaining) represent approximately 14% of all system transformers.



Option	Capital Cost	Start	Complete
Continue to replace targeted transformers.	$500,000	01 2021	12 2021

No planned replacement program for distribution transformers and the replacement would occur organically through storm replacement or as projects occur on the pole. Substantially higher risk of a PCB containing oil spill occurring.	$0	NA	
Planned replacement of PCB transformers only through programmatic work over the next 20 years.	$670,000	01 2021	12 2041

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

When the program began in 2011, there were over 17,000 targeted transformers. Currently, .02% of the 17,000 are remaining. This program has been successful in replacing targeted transformers.

Metrics considered during the analysis of this program included;

- Count of remaining transformers
- Historical review of yearly planned vs. actual transformers
- Yearly budget to actual spend

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 requested capital cost amount will be spent on replacing targeted TCOP transformers for newer models that do not contain PCBs. The costs associated with the change outs will be for designs, labor, and material associated with each replacement.

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 outcomes of this business case impact each construction office and their remaining TCOP transformers. The work to replace the targeted transformers is widely used for fill-in work for crews. There is also an environmental impact if spills were to occur.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

This Program has been funded since 2011. There were several alternatives that considered different implementation schedules. The current approach is considered the best solution for mitigating environmental risk.

Two alternatives exist as mentioned above.

1. No planned replacement program for distribution transformers. Substantially higher risk of a PCB-containing oil spill occurring. Transformers would be replaced through a reactionary method either through a spill that may occur, through storm or other type of damage

replacement or through random projects. Transformers containing PCB oils would remain active in our system for years through this method.

2. Planned replacement of PCB transformers only through programmatic work. This method would be a very slow pro-active progression. Through this method, transformers containing PCB oils would also remain active in our system for years.

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. spend, and transfers to plant by year.

This program has been in operation since 2011 and is set to be completed by the end of 2021. The newly installed transformers and other materials become used and useful immediately at the time of install. Transformers are replaced throughout the year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program aligns with the company's strategic vision, goals, objectives and mission statement with its focus on customers by reducing environmental impacts through replacement of older transformers containing PCBs.

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 has been in operation since 2011. Currently there are 264 targeted transformers remaining (as of May 30, 2020). The Transformer Change-Out Program (TCOP) work is needed for the following reason. Asset Management periodically reviews maintenance strategies.

The targeted transformers contain, or have the potential to contain, Polychlorinated Biphenyls (PCB) oil. PCBs and PCB wastes are regulated by both the Washington Department of Ecology, through the Dangerous Waste Regulations, Chapter 173-303 WAC, and by the U.S. Environmental Protection Agency under 40 CFR Part 761, the Toxic Substances Control Act. The transformers to be removed early in the program are those that are most likely to have PCB containing oil and their replacement will reduce the risk of PCB containing oil spills which are a safety, environmental, and a public relations concern.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista stakeholders include;

- The Asset Maintenance Department who is responsible for the work.
- The Environmental Department that is responsible for our environmental footprint in our service territory.
- Electric Operations that will perform the construction work.
- Asset Management for tracking system reliability and risk.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

This program is managed by the Asset Maintenance Department and progress is overseen by the Operations Round Table

3.2 Provide and discuss the governance processes and people that will provide oversight

Early in the program, asset condition and outage information were collected and analyzed by Asset Management. This information was reviewed with Asset Maintenance to establish an effective risk mitigation plan that prioritizes work by frequency and duration of outages.

Currently, the Environmental group provides prioritization guidance as needed. Asset Maintenance manages the program and collaborates with Electric Operations and Contractors to coordinate the work. Asset Maintenance tracks the work budget, scope, and schedule.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Through existing work planning documentation and through recommendations from the ORT.

The undersigned acknowledge they have reviewed the Distribution Transformer Change Out 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.

Distribution Transformer Change Out Program

Signature:	Amy Jones	Date:	8/2/20
Print Name:	Amy Jones		
Title:	Asset Maintenance Business Analyst		
Role:	Business Case Owner		

Signature:	David Howell	Date:	8/2/20
Print Name:	David Howell		
Title:	Director of Operations		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Downtown Network – Asset Condition

EXECUTIVE SUMMARY

The Downtown Network Asset Condition budget is intended to enable the replacement of aging equipment inside Avista's Downtown Network service territory, located in Spokane, WA, between I-90 and the Spokane River, and between the Ash/Maple and Browne/Division corridors. This business case's requested budget is $2-4M annually throughout the next five years, based on a combination of historical spends and a projection of levelized replacement costs for the categorized fleets of assets that exist in the Downtown Network. The requested budget is a "middle of the road" option that needs to increase in out years as a bow wave of (primarily) older structural equipment comes due for replacement.

Examples of projects funded in this business case include replacement of failing manhole/vault roofs, changing out dangerous live front network protectors, replacing collapsed/leaking cable splices, and installing new transformers when conditions indicate imminent failure.

Delays or cancellations of funding to this business case will result in increased threats to employee safety (arcflash incidents leading to severe burns and or death) and increased possibilities of catastrophic and potentially fatal public accidents, such as car/semi/bus traffic collapsing through a failed vault roof, or a manhole fire causing mass casualties during crowded Downtown events such as Bloomsday, Hoopfest, or the Lilac Parade.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Brian Chain*	*Initial draft of original business case*	*6/30/2020*	
1.0		*Updated Approval Status*		*Full amount approved*

Downtown Network – Asset Condition

GENERAL INFORMATION

Requested Spend Amount	$2M-4M annually (see Funds Request)
Requested Spend Time Period	5 years
Requesting Organization/Department	C57 Downtown Network
Business Case Owner | Sponsor	Ryan Bradeen | David Howell
Sponsor Organization/Department	Electric Operations
Phase	Execution
Category	Program
Driver	Asset Condition

Downtown Network – Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Downtown Network Asset Condition budget is intended to deal with proactive and reactive replacements of equipment due to age and condition. The budget covers both electrical and structural elements of the Downtown Network system.

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 major driver in this business case is Asset Condition. Our Downtown Network equipment fleets are aging; by managing the overall conditional age of each class of equipment, Avista can minimize system down time (outages) as well as public/employee safety hazards.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Electrically, our network protector fleet is relatively new. However, there remain a few older style “live front” network protectors that are very dangerous to work on while energized. As such, Avista has committed to take outages in order to do any work on these protectors. We are changing these out to newer dead front designs as fast as budget and resources allow. Without replacement we risk either an employee accident (which may also affect the public from a safety perspective), customer outages, or more likely, both.

Our transformer fleet is more widely aged. We test for condition as part of a four-year inspection cycle and replace units as soon as they show signs of failure (usually due to dissolved gas analysis of the oil quality inside each unit). Without replacement, these transformers will fail in place. Generally this means a catastrophic failure such as a ruptured tank, with the possibility of a fairly large oil spill and the likelihood of a transformer vault fire, both of which have severe public safety ramifications.

Our cable fleet is the oldest electrical component on our system. We average several cable failures per year. We need to accelerate the replacement of the oldest style of cable, paper-insulated lead cable (PILC) or we will face even more failures in the years to come. Failures generally cause outages but can also cause manhole fires, as observed on Riverside in 2020.

Structurally, a significant portion of our transformer vaults are approaching 100 years old. An even more significant portion of our manholes are constructed of brick. Despite most structures being underneath downtown arterial streets, they are designed to accommodate horse and buggy loading profiles more than HS20 truck axles or STA busses. Structural failures are a significant public safety risk and generally shut down multiple lanes of arterial streets for months while fixes are retroactively implemented (e.g. Spokane Falls Boulevard in 2018, Washington in 2019, etc).

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.

Successful use of Asset Condition budget will prevent future increases of the “Failed Plant” budget item that is contained within this business case. If the Failed Plant BI is seen increasing, then Asset Condition dollars are not being appropriately supported or allocated.

Appropriate use of the Failed Plant BI is critical to utilizing this as a success metric.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

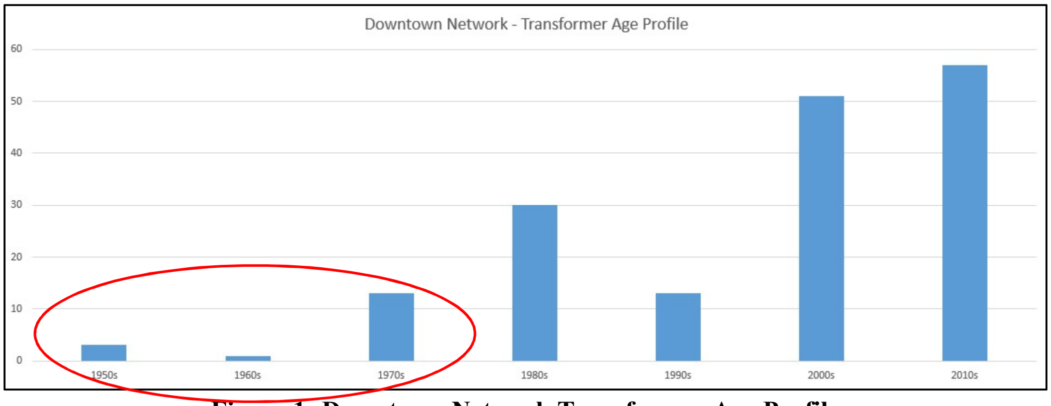


Figure 1: Downtown Network Transformer Age Profile

Downtown Network – Asset Condition

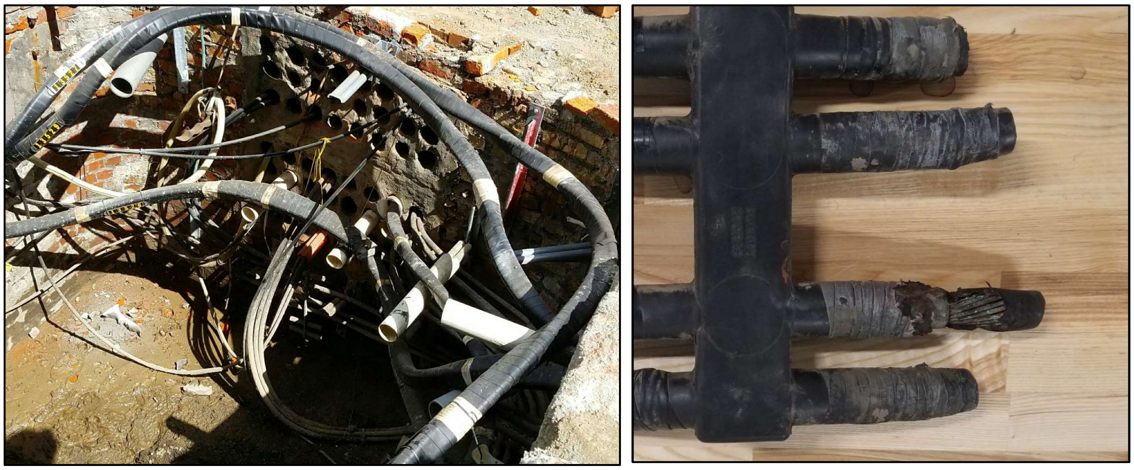


Figure 2: Brick handhole w/assortment of PILC cable / Failed insulation on grid bus (Hotel Ruby Service)

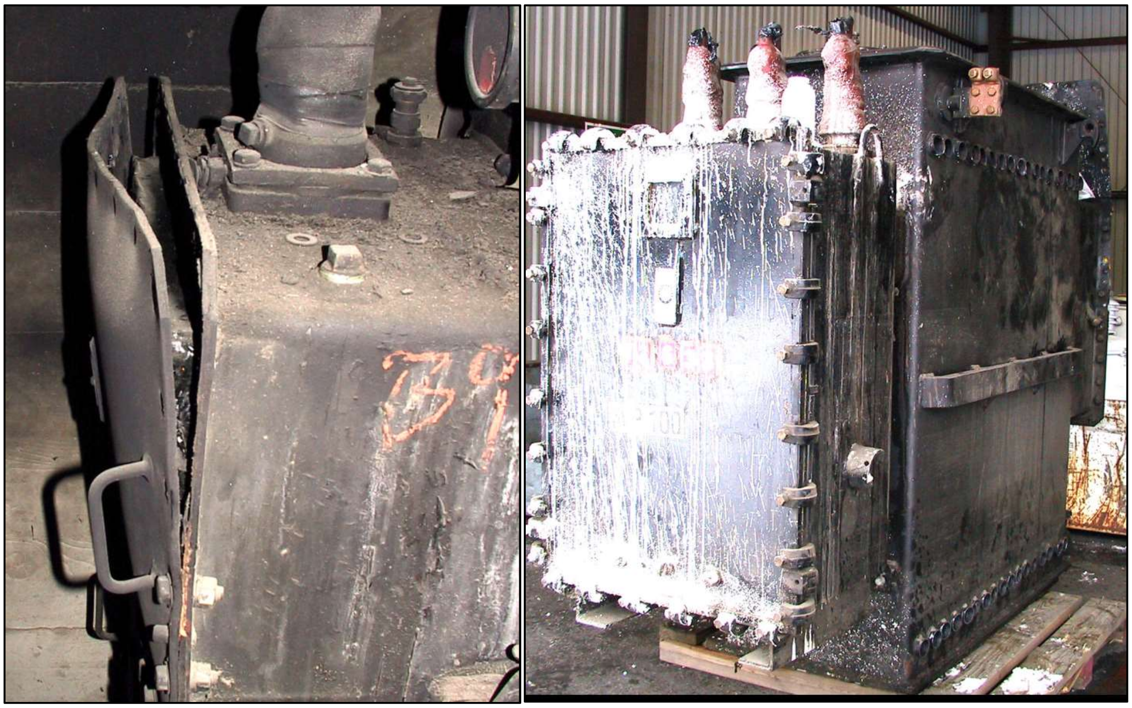


Figure 3: Faulted primary terminations on network transformer / Faulted network transformer

Downtown Network – Asset Condition

Figure 4: Faulted PILC cabling from peak summer 2018 loading period

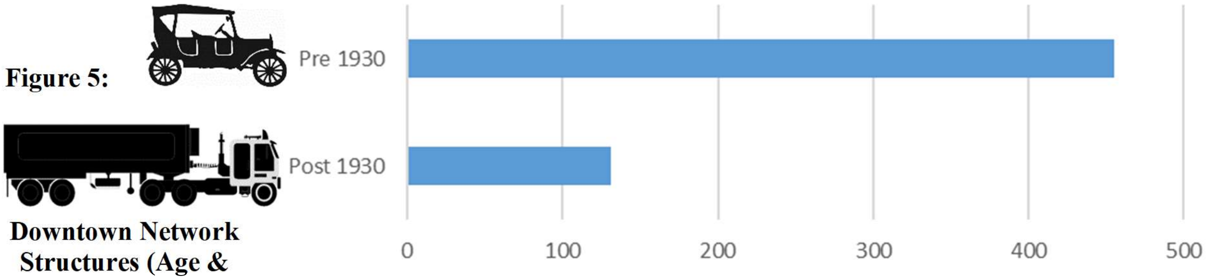


Figure 5: Downtown Network Structures (Age & Design Profile)

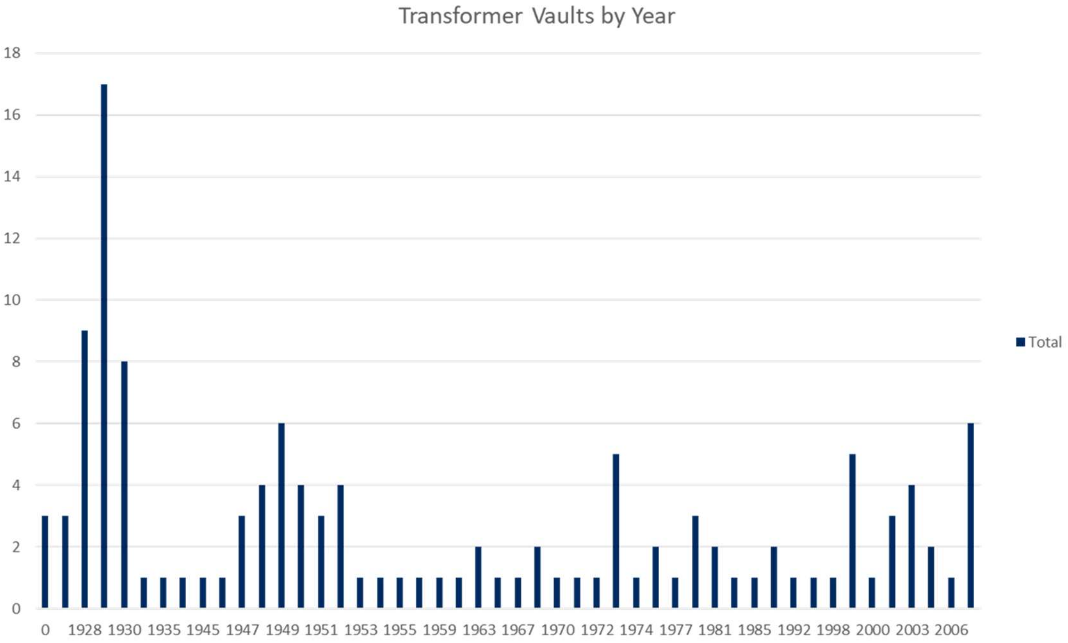


Figure 6: Transformer Vault Age Profile

The following Alternatives are presented as a range of options under which this business case could be funded. Remember that this Asset Condition business case/ER supports a Failed Plant BI, so even the Do Nothing option carries some cost.

Downtown Network's recommendation is to start at the Alternative 2 funding level and systematically increase toward (if not all the way to) the Alternative 3 funding level. This recommendation allows time to onboard and qualify contractors in the extremely difficult downtown environment, build standards and inspection models to support these contractors and our internal crews, and finish the field assessments necessary to more fully document a complete Asset Management program for the Downtown Network equipment fleets.

Alternative 1: Do Nothing/Reactive Replacements

The do nothing option is essentially "breakdown replacements" using only Avista crews. Customer growth and road move related work must be prioritized higher than asset condition projects. City projects and customer growth are currently higher than they have been in the past 15 years and are expected to continue for the next five years. Therefore this option is expected to continue to build a "bow wave" of failed equipment and facilities.

Cost: $1M (for 2020, increasing "failed plant" will increase over budget period)

Alternative 2: Eliminate Worst Known Electrical and Structural Issues

This option mitigates the worst known existing equipment and facility threats (while ignoring anything that has not recently been a visible failure threat). Avista Downtown Network crews must focus on enabling and inspecting limited contract crews, and replacing failed or near-failed equipment such as transformers, protectors, grounds, cable, structures and duct banks. The prioritization of replacements will be considered together based on estimated reduction of risk of catastrophic failure…but without being compared against the entire fleet as a whole.

Cost: $2M (for 2020, increasing "failed plant" will increase over budget period)

Alternative 3: Create/Follow Programmatic Replacement Programs

The proposed programs would incorporate all known data (along with any data that must be sought out in the field) and recommend replacements to conquer the existing bow wave of electrical equipment and structures that has built up due to decades of underfunding. A consultant proposal to do this work for Avista is already in hand and ready to approve, but does require O&M funding commitment from both Engineering and Operations.

This option incorporates various sources of recent surveys and inspections, in order to create programmatic replacement programs for all classes of equipment and structures. This will involve creating adjusted age profiles that direct the replacement of the right assets at the right time. It will lead to better use of capital dollars due to the identification of synergies between different classes of equipment. It will also reduce Avista liability in the busy and high risk service territory Downtown, while building better relationships with both our customers and the City of Spokane.

Cost: $5.7M

Option	Capital Cost
Reactive Replacements, Rely on Failed Plant BI	$1M, increasing
Eliminate Worst Known Electrical & Structural Issues	$2M, increasing
Create/Follow Complete Systematic Replacement Programs	$5.7M

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Our electrical fleet downtown consists of:

- 181 network transformers and 181 network protectors
- A budget estimate to replace the entire fleet of transformers and protectors (without replacing associated structural elements) is $48M...
- Given an industry standard life assumption, a levelized (present value) annual investment for just transformers and protectors should be **$1.2M.**
- There is approximately 96,000 feet of primary cabling in the Downtown Network. Assuming standard industry life cycles, a levelized (present value) annual investment for triplex primary cable should be around **$600k.**
- There is approximately 125,000 feet of secondary cabling in the Downtown Network. The levelized (present value) annual investment for secondary cable should be around **$1.1M.**

Downtown Network – Asset Condition

- The Downtown service area is the oldest in the company and it is most obvious when looking at building services. Many buildings are refreshing switchgear, providing us the perfect opportunity to also refresh the often 80+ year old service cabling. Presently services are only replaced after catastrophic failures and during customer-requested upgrades (rare, but largely funded by the customer).
- The Downtown Network street light fleet consists of approximately 200 lights. A 2019 pole by pole survey marked 64 of these as "severely deteriorated" and 3 more as "unsafe". Cabling and conduit between these lights is often re-purposed 4 kV PILC DC cable dating back a century (which is why many "underground-fed" lights are now connected with overhead duplex, on poles that are not rated for such a connection). We have done no proactive replacements of light strings for decades due to a lack of funding. The street lights compare very poorly when viewed down the street from the City of Spokane's ongoing streetlight refresh projects (something that the City has been very vocal about).
- Based on the estimates above, a total levelized annual investment of **$3.4M** would be sufficient to keep up with our aging Downtown electrical fleet.
- Realize that many decades passed Downtown with less investment than necessary, on a levelized basis, which has created a bow wave. This means that the VROM-based levelized annual investments listed above are likely lower than what is actually needed. For example, the age profile shown below indicates that 16 transformers are presently past industry-standard end of life.
- Present funding levels only support replacement of two transformers per year (outside of growth, and assuming Failed Plant across all asset classes does not negatively impact our limited Asset Condition budget). Further analysis (an adjusted age profile) would likely add to the number of units past recommended end of life. Similar conditions can be observed for other asset classes.
- 73% of the ~600 manholes in the Downtown Network were constructed prior to 1916. An annual budget of **$700k** is enough to fund a levelized replacement program; however, the bow wave built up by over a century of underfunding replacements will take more support.
- Transformer vault structures in the Downtown Network have an average age of around 80 years. Levelized replacements could be funded with only **$500k** per year; however, the bow wave built up by more than a century of underfunding replacements will take more support.

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 annual amount requested will fund replacements of the following:

- The worst ranked network vault transformers, based on visual and DGA inspections from prior maintenance years, as shown in the Transformer Replacement Program document available on the Downtown Network sharepoint site.
- Live front network protectors (ten remain on the system at this point in time).
- PILC cable splices (refer to the Downtown Network GIS Online system, which identifies every leaky splice location as a manhole unable to be entered, per WAC.
- Services and street lights that are ranked as unsafe per survey results documented in Downtown Network GIS Online system.
- Manholes with known poor structural condition (roofs, walls).
- Transformer vaults with known poor structural condition (roofs, walls, grates).

Annual job planning is performed at the end of each prior year; job estimates are prioritized by Downtown Network management, engineering, and foremen, and cut off when budget runs out. In past years, the Asset Condition budget has been fully allocated at the beginning of the year and fully spent by around September of each year. At that point the budget has been throttled for the remainder of the year; despite knowing about severely deteriorated installations (cracked/spalling manhole roofs in traffic, multiple leaky splices/cable in one hole, live front protectors, etc), no work is performed on them.

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 outcome of this business case affects most especially, Distribution Operations, and Claims. Successful replacement of assets will lessen impacts to Failed Plant emergency responses and subsequent damage claims made by customers and the public.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See alternatives discussed at beginning of Section 2, for a look at the possibilities considered for Downtown Network's Asset Condition program as a whole.

On a micro level, alternatives for each individual project are discussed by the Downtown Network management, engineering, and foremen, as part of the annual job planning exercise. For some projects further Scoping Documents are developed; these often consider possible alternative solutions. These are available on the Downtown Network shared drive.

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.

This Business Case transfers to plant monthly; dollars are "used and useful" as soon as the smaller individual projects contained within this Business Case are energized.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This Business Case invests in the heavily utilized core of Spokane. It supports both the general public and a specialized business community that relies on extremely reliable power. It puts our customers first by ensuring that equipment failures do not negatively impact our reliability track record while also improving items (live front breakers, manhole/vault roofs and grates) that directly impact anybody who lives, works, or visits downtown Spokane.

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

As discussed earlier in Section 2.1, a simple analysis of the replacement cost of both electrical and structural components of the Downtown Network clearly shows that Avista has underinvested in refreshing equipment. Even with questionably long average lifespans of equipment (e.g. transformer vaults aging past 100 years) there is a bow wave of work to be done in order to catch up. Continued underinvestment will only make the problem worse.

From a big picture standpoint, there will come a time when equipment fleet replacement levels *will* catch up, however. For the most part this does not occur within the 5 year planning horizon. We will need to watch for when it does occur though, and draw down or redirect spending when appropriate. For example, the network protector fleet is relatively new. We have ten live front breakers left to replace and after that, protector replacements are of a questionable priority.

If all other classes of equipment had no bow wave of replacements to be addressed, this should result in a decrease in necessary funding at the end of 2021, when the live front replacements are scheduled to be completed. However, the needs of the structural portion of the system, which are much older and dilapidated, will easily subsume the dollars going toward live front replacements (and then some).

The conversation about shifting dollars from protector replacements to structural replacements is one example of the kind of discussion that goes on as part of Downtown Network's annual job planning exercise. This is the forum that will allow Downtown Network management, engineering, and foremen to continue evaluating prudency. Similar discussions will be ongoing, reflected on both the job planning board and in future request years.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

- Downtown Network
- Claims
- Operations
- Distribution Operations
- System Operations
- Generation Control Center
- Regional Business Managers

2.8.2 Identify any related Business Cases

This business case supersedes ER 2058, which used to encompass both ER 2062 (Asset Condition) and ER 2063 (Performance & Capacity). ER 2058 has been defunct for several years.

3.1 Steering Committee or Advisory Group Information

Projects (both the Vault Integration Project and smaller programmatic capacity-driven projects) are prioritized by Engineering (Brian Chain, Landen Grant) and Downtown Network management (Ryan Bradeen, David Howell), based on input from the field personnel as well as data gathered from various systems and surveys.

3.2 Provide and discuss the governance processes and people that will provide oversight

Job planning and budget monitoring is a constantly iterative process Downtown. An annual job planning board is constructed ahead of the beginning of each year, including carry over from the prior year, known upcoming projects, and slack for unknown customer-driven and failure-driven projects.

Budget tracking and balancing occurs on a monthly basis throughout the year and is reviewed with Engineering (Brian Chain and Landen Grant) and Downtown Network management (Ryan Bradeen and David Howell). Adjustments are made as necessary to ensure that required projects have the budget resourcing they need to be completed, and also to make sure that the overall budget is not being exceeded without approval.

See the following chart for high points of this process.

Offramps are available at each step of this process that allow individual jobs to be stopped or delayed if more information comes to light that makes the project less prudent (e.g. delay in connected customer work, City re-pave jobs that impact our schedule, or de-prioritization of the job in question due to other discoveries on the system as a whole).

Downtown Network – Asset Condition

Annual Planning Exercise

(Project Intake, Estimating and Prioritization)

Area Manager, Area Engineer, Foremen

Job Scoping & Design

(Addition of Details, Better Estimate)

Area Engineer

Job Execution

(Discovering "unknowable" Unknowns)

Foremen and Crew

Monthly Budget Monitoring

(Comparison of Expenditures vs Scope vs Total Budget)

Area Manager, Area Engineer

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Presently, decisions to add, delete, or modify projects on the job planning board are tracked in versions of the planning board spreadsheet, stored on the Downtown Network shared drive.

Downtown Network – Asset Condition

The undersigned acknowledge they have reviewed the Downtown Network – Asset Condition 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: Ryan Bradeen Date: 1-5-2022

Print Name: Ryan Bradeen

Title:

Role: Business Case Owner

Signature: David Howell Date: 8/2/20

Print Name: David Howell

Title: Operations Director

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Downtown Network – Performance & Capacity

EXECUTIVE SUMMARY

The Downtown Network Performance & Capacity budget is intended to enable the installation of new and upgraded equipment to cover deficiencies in Avista's ability to serve customers inside the Downtown Network service territory, located in Spokane, WA, between I-90 and the Spokane River, and between the Ash/Maple and Browne/Division corridors. This business case's requested budget is $1.2M based on historical spends.

Examples of projects funded in this business case include larger vaults to allow for additional grid transformers to be installed, larger duct banks to support additional grid cable to be installed, and larger transformers to support increasing grid loading. This business case also covers the ongoing installation of fiber-optic communications to network protectors for control and data acquisition, to increase efficiency in construction and improve reliability for customers inside the Downtown Network.

Delays or cancellations of funding to this business case will result in trends down in reliability to Avista's Downtown Network customers, less efficient construction overall and, worst case, the inability to serve Downtown Network customers under contingency conditions during peak load periods.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Brian Chain*	*Initial draft of original business case*	*6/30/2020*	
1.0		*Updated Approval Status*		*Full amount approved*

Downtown Network – Performance & Capacity

GENERAL INFORMATION

Requested Spend Amount	$1.3M-2.2M annually (see Funds Request)
Requested Spend Time Period	5 years
Requesting Organization/Department	C57 Downtown Network
Business Case Owner | Sponsor	Ryan Bradeen | David Howell
Sponsor Organization/Department	Electric Operations
Phase	Execution
Category	Program
Driver	Performance & Capacity

Downtown Network – Performance & Capacity

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Customer growth in the Downtown Network, on a collective basis, drives the need for upgrades of Avista's system further upstream of the radial service feeding the customer. Per Avista's ESR, upgrades to the network itself are done at Avista's cost. Without these upgrades, the system will lack the capacity to service customers without overloading network cables. These capacity issues are identified in a similar manner to those on Avista's transmission system, with ongoing powerflow studies performed in PowerWorld, using real time data whenever possible (e.g. AMI metering output).

Beyond these basic capacity issues, which are fixed on a programmatic basis, a very large specific project is being funded under this business case, due to the lack of support for individual business case funding. The Vault Integration Project, chartered at $5.2M, is installing fiber-optic based SCADA (System Control and Data Acquisition) to all of Avista's ~100 transformer vaults. With this system in place, our capacity planning will be much improved (due to even more real time data being available to assist modeling). Our operational procedures will also be vastly improved, with remote monitoring and control mitigating the hazards of individual vault visits in many cases. Our reliability will be improved, as outage responses can be sped up due to readily-available information.

1.2 Discuss the major drivers of the business case

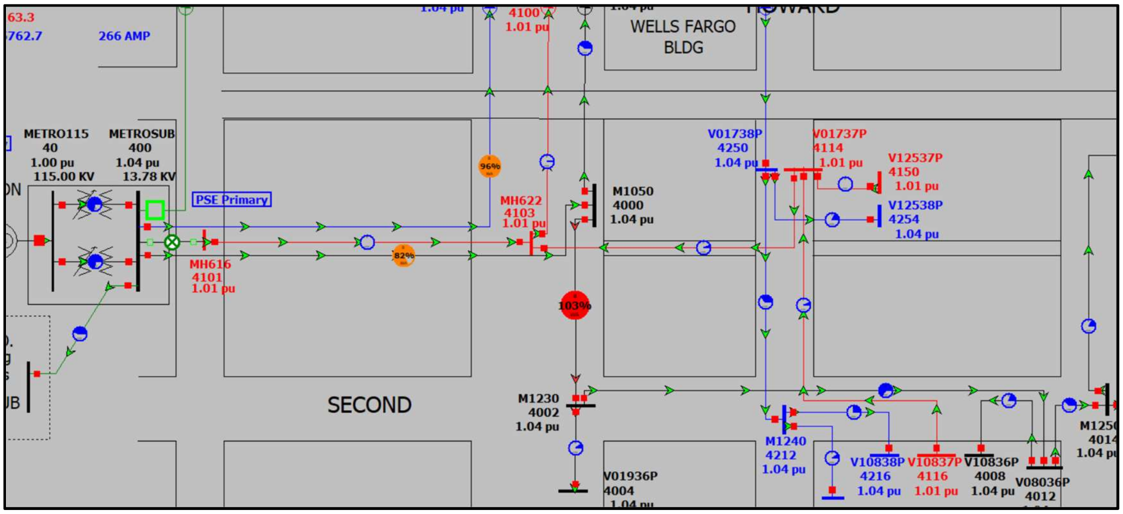
The major driver in this business case is Performance & Capacity; however, with regard to the Vault Integration Project, almost every other business driver also applies.

As discussed above, the benefit to our customers is similarly wide ranging. At the core, the benefit is that the system remains reliable due to capacity increases being installed where they are necessary in order to maintain reliable service by avoiding cable overloads and subsequent outages. However, the inclusion of the Vault Integration Project also provides increased response times when there are outages, better safety for our crews by mitigating in person vault visits, and better data available for capacity planning. This data allows us to use our PowerWorld model accurately and delay capital projects until they are definitively proven as necessary, thereby lowering upward pressure on rate increases toward all customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Downtown Network – Performance & Capacity

Cable overloads that are identified in PowerWorld that are not fixed prior to the next peak demand period will result in customer outages. Due to the nature of the Downtown Network these outages will be widespread (at least ¼ of downtown Spokane). An example of the modeling software is shown below; note that while "System Normal" overloads are watched for (as with the rest of our radial distribution system), the real focus in the Network is "Contingency" modeling, to see what happens next when each element of the system is lost. In this sense, the Downtown Network modeling works to produce projects in a fashion that is much more similar to Avista's Transmission Network than it is to the radial distribution system.



Additionally, the Vault Integration Project mitigates a host of issues as discussed above. Much of the rest of the network industry has already implemented similar measures. Avista is doing both our customers and employees a disservice by not following suit, with customers paying for upgrades which may have been forestalled given better operational knowledge, and employees (cablemen) taking risks which may have been fully mitigated by operating dangerous electrical equipment remotely via communications.

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.

Continued investment in network capacity where shown as necessary should continue the low amount of outage minutes experienced by Downtown Network customers.

Capital investment in this business case after the next two years (where investment is asked to increase in order to allow for faster completion of the Vault Integration Project) should have less "upward pressure" as individual overloads predicted by the PowerWorld model are shown not to actually be an issue compared to real time measurements.

In person vault visits during switching should reduce dramatically as new operational procedures are implemented as part of the Vault Integration Project. These procedures are already in draft format and being reviewed/approved by Safety & Health, L&I, and System/Distribution Operations.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Refer to the Vault Integration Project Charter and Scoping Memo for more detail around the spending on this project.

https://sp2016.corp.com/sites/sp/DTNetwork/_layouts/15/start.aspx#/SitePages/Home.aspx?RootFolder=%2Fsites%2Fsp%2FDTNetwork%2FShared%20Documents%2FCommunications&FolderCTID=0x0120000A381BA032775F47AF043FFE7EB5DCE1&View=%7BF2BD4327%2D2C21%2D4CDD%2D8022%2D8008F47F9D84%7D

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 business case supports the installation of new assets that support growth on the system or improved operational efficiencies, not asset replacements.

The individual capacity increases that are installed as part of this business case are modeled and driven on an annual basis. Without additional capacity, cable overloads will result and large scale network quadrant outages will occur. Alternatives for each individual small cable or transformer upgrade are considered by Engineering on every single capacity issue.

The Vault Integration Project portion of this Business Case will result in reduced O&M vault visits as described in the attached Charter.

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Reduced O&M and overtime expenditures were considered in the original Vault Integration Project charter. The improvement to Downtown Network crew safety was also a factor; transformer vault entry in the middle of downtown arterial streets is perhaps the worst traffic control problem that any crew at Avista will ever encounter. The project reduces the amount of "patrol" work that a crew must perform at the end of cutover jobs; these jobs often extend to the end of allowable crew working hours i.e. the network patrol must occur at the end of a very long shift when crews are most likely to have an accident while blocking a manhole entry in the middle of 1st Ave while crawling down a ladder into an energized vault.

See attached project Charter.

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 Vault Integration Project portion of this Business Case is scheduled to be spent over the next few years (depending on level of budget support and amount of other critical capacity upgrades that cohabit this Business Case). Presently we are about 40% installed with one quadrant (Metro West) commissioned and one quadrant (Metro East) partially installed.

The Vault Integration Project portion of this Business Case reduces upward pressure on O&M going forward as described in the attached Charter. Reduced truck rolls, regular time and overtime crew callouts, and vault visits in the middle of busy downtown streets should all be reduced. Estimated O&M reductions are in the $50-100k annual range, based on cableman salaries, overtime rates, and overheads. Annually these do vary based on the number of outages that occur.

Note that it is also expected that more accurate real time field measurements should result in delayed capital expenditures to mitigate perceived capacity issues that do not show up in the real time data. This should provide downward pressure inside the Downtown Network Performance & Capacity Business Case.

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 Vault Integration Project will impact System and Distribution Operations processes. Many issues in the field that would result in a crew callout will now, at a minimum, have remote monitoring operations that precede the callout. In many cases, the results of these remote monitoring steps should mitigate the need for the callout entirely.

Ongoing work with System and Distribution Operations management is producing new procedures to guide operations as it incorporates this new system. Note that it is difficult to implement new procedures across only a portion of the system; full benefits can only be realized after enough funding is provided to finish the project.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

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.

Capacity upgrades completed as part of the normal course of business under the “Program” portion of this Business Case generally transfer to plant monthly, as they are used and useful immediately upon becoming energized.

The Vault Integration Project expenditures have been transferring to plant as network quadrants become commissioned i.e. data starts flowing into the SCADA historian software from our fiber connected field devices. At this point the data is available for both operations and future capital planning, and again, it is expected that this data will put downward pressure on the cost of both of these.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Without solutions to network capacity issues, blackouts will result. The programmatic portion of this annual spend is intended to prevent these reliability issues by providing appropriate upstream capacity to support customer load. This puts our customers at the forefront by providing the reliability they have come to expect from Avista in downtown Spokane.

The Vault Integration Project improves employee safety, streamlines operational efficiency, and provides information that guides our future investments in our system. All of these, and especially the latter, put downward pressure on the overall future cost of service to 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

Project prudency is explained further in the attached Project Charter, for the Vault Integration Project. The project sunsets as expenditures finish up over the next two years. No review of prudency has been scheduled prior to project completion.

A project offramp could be taken at the end of the Metro quadrant portions of the project, leaving Post Street unfinished. This would severely hamper our ability to implement new procedures that take full advantage of the new communications system.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Customers and stakeholders that interface with the Vault Integration Project are identified in the Attached project charter and scoping memo.

2.8.2 Identify any related Business Cases

This business case supersedes ER 2058, which used to encompass both ER 2062 (Asset Condition) and ER 2063 (Performance & Capacity). ER 2058 has been defunct for several years.

3.1 Steering Committee or Advisory Group Information

Projects (both the Vault Integration Project and smaller programmatic capacity-driven projects) are prioritized by Engineering (Brian Chain, Landen Grant) and Downtown Network management (Ryan Bradeen, David Howell), based on input from the field personnel as well as data gathered from various systems and surveys.

3.2 Provide and discuss the governance processes and people that will provide oversight

Job planning and budget monitoring is a constantly iterative process Downtown. An annual job planning board is constructed ahead of the beginning of each year, including carry over from the prior year, known upcoming projects, and slack for unknown customer-driven and failure-driven projects.

Budget tracking and balancing occurs on a monthly basis throughout the year and is reviewed with Engineering (Brian Chain and Landen Grant) and Downtown Network management (Ryan Bradeen and David Howell). Adjustments are made as necessary to ensure that required projects have the budget resourcing they need to be completed, and also to make sure that the overall budget is not being exceeded without approval.

See the following chart for high points of this process.

Offramps are available at each step of this process that allow individual jobs to be stopped or delayed if more information comes to light that makes the project less prudent (e.g. delay in connected customer work, City re-pave jobs that impact our schedule, or de-prioritization of the job in question due to other discoveries on the system as a whole).

Annual Planning Exercise

(Project Intake, Estimating and Prioritization)

Area Manager, Area Engineer, Foremen

Job Scoping & Design

(Addition of Details, Better Estimate)

Area Engineer

Job Execution

(Discovering "unknowable" Unknowns)

Foremen and Crew

Monthly Budget Monitoring

(Comparison of Expenditures vs Scope vs Total Budget)

Area Manager, Area Engineer

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Presently, decisions to add, delete, or modify projects on the job planning board are tracked in versions of the planning board spreadsheet, stored on the Downtown Network shared drive.

Downtown Network – Performance & Capacity

The undersigned acknowledge they have reviewed the Downtown Network – Performance & Capacity 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: Ryan Bradeen
Date: 12/28/20
Print Name: Ryan Bradeen
Title: Network Operations Manager
Role: Business Case Owner

Signature: David Howell
Date: 8/2/20
Print Name: David Howell
Title: Operations Director
Role: Business Case Sponsor

Signature:
Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Electric Replacement and Relocation

EXECUTIVE SUMMARY

The Electric Replacement and Relocations (Road Moves) program is driven by compliance mandated by the “Franchise Agreement” contracts with local city and state entities and “permits” issued by Railroad owners. Within each agreement are provisions for relocation of utilities at the request of the right-of-way (ROW) owner. Under a Franchise Agreement or Permit, Avista is allowed to occupy space within a ROW owned by the respective jurisdiction in order to serve its customers. Electric relocations occur every year during the construction season, but are unplanned, so historical trends are used to estimate the annual cost to fully fund all the relocation projects. The annual costs of electric relocations have very little variance year to year, therefore fully funding the business will likely ensure all electric relocations under Franchise Agreements or Permits will be completed. This is mandatory work to maintain compliance with existing franchise and operating permits with state highway districts and railroads. This impacts WA and ID Customers.

The Electric Relocations business case is unplanned and demand driven work, contractually obligated, and adds high risk to the company if not completed. Funding allocation is based on historical spending trends. The average historical spend for Electric Relocation over five years is $2.7 million (three-year average = $3.1 million). Because electric relocations are directly correlated with the number of highway and street projects, the reason for the upward trend in spend is likely an increase in transportation project spending.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Initial draft of 2020 Business Case Refresh*	*6/30/2020*	
1.0				
1.1				
2.0				

Electric Replacement and Relocation

GENERAL INFORMATION

Requested Spend Amount	$3,000,000 annually
Requested Spend Time Period	Ongoing Program
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Amy Jones | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Electric Distribution and Transmission Replacement and Relocations (Road Moves) program is driven by compliance mandated by the "Franchise Agreement" contracts with local city and state entities and "permits" issued by Railroad owners. A "Franchise Agreement" generally refers to a non-exclusive right and authority to construct, maintain, and operate a utility's facility using the public streets, dedications, public utility easements, or other public ways in the Franchise Area pursuant to a contractual agreement executed by the City and the Franchisee. Although each Franchise Agreement or permit is a little different, they all serve a similar purpose in providing utility access along city, county, state and railroad right-of-way (ROW). The agreement(s) make provisions for Avista to install electric equipment along these ROW's in order to provide service to Avista customers.

Within each agreement are provisions for relocation of utilities at the request of the ROW owner. These requests are usually driven by road and or sidewalk re-design projects.

> For reference, **franchise 95-0990** recorded with Spokane County paragraph VI states ***"If at any time, the County shall cause or require the improvement of any County road, highway or right-of-way wherein Grantee maintains facilities subject to this franchise by grading or regarding, planking or paving the same, changing the grade, altering, changing, repairing or relocating the same or by constructing drainage or sanitary sewer facilities, the grantee upon written notice from the county engineer shall, with all convenient speed, change the location or readjust the elevation of its system or other facilities so that the same shall not interfere with such County work and so that such lines and facilities shall conform to such new grades or routes as may be established."***
>
> For example, a State Department of Transportation (DOT) is widening an intersection or highway, which requires Avista to relocate their overhead or underground electric facility to accommodate the new DOT design. A smaller example for instance is a local municipality is installing new ADA ramps on the corners of local street intersections, which sometimes requires Avista to relocate a utility pole to accommodate the new ramp design.

The asset conditions replaced through Electric Relocations can vary since the relocations are unplanned and therefore not coordinated with Avista's Asset Maintenance programs. Most assets in an Electric Relocation project are replaced because they are unsalvageable and close to their useful life. In the case of relocating newer assets, efforts are made to re-use as much material as possible.

Under a Franchise Agreement or Permit, Avista is allowed to occupy space within a ROW owned by the respective jurisdiction in order to serve its customers. Electric relocations occur every year during the construction season, but are unplanned, so historical trends are used to estimate the annual cost to fully fund all the relocation projects. The annual costs of electric relocations have very little variance year to year, therefore fully funding the business will likely ensure all electric relocations under Franchise Agreements or Permits will be completed.

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

This major driver of this business case is Mandatory & Compliance. Franchise agreements, typical state highway and railroad permits, and DOT prescribe that the utility will relocate at their expense when in conflict with entity activities. Mandatory work to maintain compliance with existing franchise and operating permits with state highway districts and railroads.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This program has been funded for several years and ensures compliance with our Franchise agreements and/or railroad permits. If not funded, we would be out of compliance with our Franchise agreements and/or railroad permits. The work would need to occur and would be funded under another business case.

Work under Franchise Agreements or Permits are contractual, agreed upon, and if the terms of the agreement or permit are not executed a breach of contract will likely ensue. Also, state and local government departments which oversee highways, roads, and city streets incorporate the guidelines set forth in the American Association of State Highway Transportation Officials (AASHTO) Roadside Design Guide into the design of the highways and roads. The guidelines are based on the type of roadway and posted speed, but generally do not allow for any fixed objects inside the traveled way or sides of the roadway (“clear zones”) for public safety. As a result, nearly all new road projects require utilities to relocate or remove all poles inside and outside the traveled way. The new roadside design guidelines allow for placement of new facility in a location that improves the safety of the driving public, thus reduces risk to Avista. Avista designers coordinate with each state or local road project to ensure the new relocations meet the clear zone standards yet minimize cost. Most Franchise Agreements have provisions to prohibit the ROW owner from requiring the utility to move the same facility more than once over a span of years, usually five.

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.

Measures to determine successful delivery on business case objectives include:

- YTD Spend
- Compliance with Franchise agreements and/or railroad permits

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

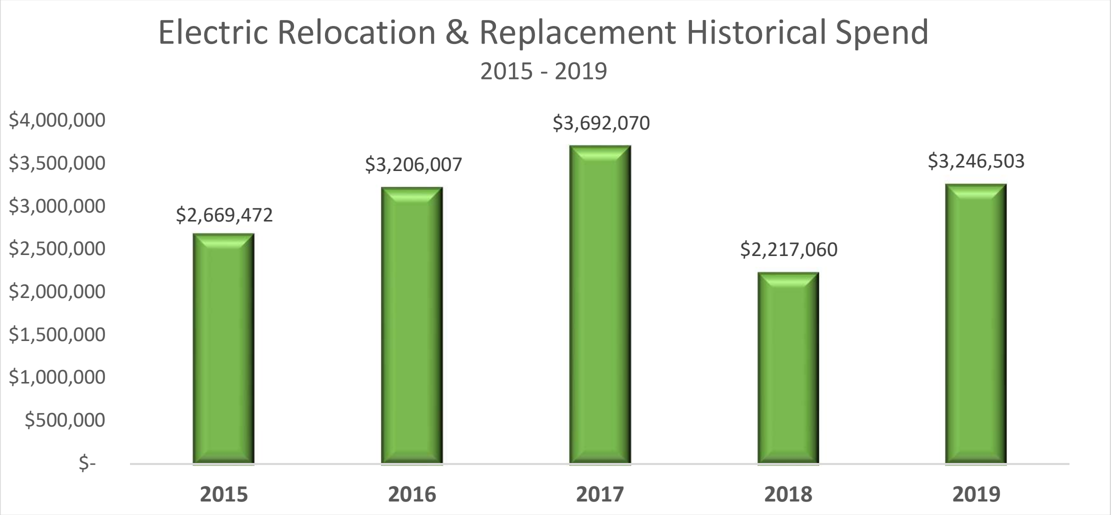
NA

Option	Capital Cost	Start	Complete
Relocate/replace facilities in conflict with street and highway projects where established franchise agreements and/or permits exist.	*$3,000,000 annually*	*Continuous Program*	
UNFUNDED: Avista would be out of compliance with established franchise agreements and/or permits if work is not completed.	*$0*		

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The Road Moves business is unplanned work, contractually obligated, and adds high risk to the company if not completed, no alternative analysis is considered. This program is demand driven and unplanned work. Funding allocation is based on historical spending trends.

The graph below shows the historical spend for Road Moves (2015 – 2020 YTD - May). The average spend over the five years is $2.7 million. Because electric relocations are directly correlated with the number of highway and street projects, the reason for the upward trend in spend is likely an increase in transportation project spending.



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 funding will enable us to relocate/replace facilities in conflict with street and highway projects where established franchise agreements and/or permits exist. The funding will ensure we are in compliance with our existing franchise agreements and/or railroad permits.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

If funded, the outcome of this business case will have minimal impact on existing operations. This funding has been in place for several years to maintain compliance with our franchise agreements and railroad permits. If not funded, the work is required to maintain compliance with our franchise agreements and/or railroad permits and will need to occur.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The work covered by this funding is mandatory to maintain compliance with our franchise agreements and/or railroad permitting. Because the Road Moves business is unplanned work, contractually obligated, and adds high risk to the company if not completed, no alternative analysis is considered. This program is demand driven and unplanned work.

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. spend, and transfers to plant by year.

This is an ongoing project. All investments/assets are used and useful at time of install.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This work is required to maintain compliance with our franchise agreements and/or railroad permits. This work focuses on our Customers and performance (safety and compliance).

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.

The work covered by this funding is mandatory to maintain compliance with our Franchise Agreements and/or railroad permitting.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal customers and stakeholders are the local area operation engineers and area construction managers

The primary external stakeholders in the business include all state and local transportation governments as well as customers since they live in the territory governed by these agencies and use the transportation system.

2.8.2 Identify any related Business Cases

NA

3.1 Steering Committee or Advisory Group Information

The Road Move work is overseen by the local area operations engineers and area construction managers.

3.2 Provide and discuss the governance processes and people that will provide oversight

The work is mostly unplanned and non-specific in nature but occurs regularly and historical averages are used to estimate a quantity. Electric Relocations (Road Moves) are agreed to and executed per the jurisdictional Franchise Agreement or Permit.

The governance in place over the business case is set by the Operations Roundtable (ORT) group, which sets forecasted budgets, monitors the incurred costs and submits any additional funds requests as needed. Oversight of the program is provided by the local area operation engineers and area construction managers manage the work as it is identified throughout the given construction season.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

For the funding: Decision making, prioritization and change requests will be documented and monitored through the Operations Roundtable (ORT).

For the work: Each office will work with their Area Engineer and impacted jurisdiction/Railroad in determining priority.

The undersigned acknowledge they have reviewed the **Electric Replacement and Relocation (Road Moves)** and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Electric Replacement and Relocation

Signature: Amy Jones Date: 08/01/2020
Print Name: Amy Jones
Title: Asset Maintenance Business Analyst
Role: Business Case Owner

Signature: David Howell Date: 8/2/20
Print Name: David Howell
Title: Director of Operations
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Electric Storm

EXECUTIVE SUMMARY

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. This business case is to fund a rapid response to unexpected damages and outages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and all other defined retirement units damaged during weather storm events. The damage can be due to high winds, heavy ice and snow loads, lightning strikes, flooding, or wildfires as an example. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. This impacts customers in WA and ID.

The annual budget amount is determined based on the historical average rate of capital restoration work including restoration activity related to MED's of relativity minor restoration impact. Request excludes costs related to very large major event days (MEDs). If not funded, the work will still occur as needed for outages caused by weather storm events or other natural disasters and would be absorbed through other business cases.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Initial draft of Business Case refresh 2020*	*7/1/2020*	
Draft	*Julie Lee*	*Revise Funds Request for 2022 5 yr plan*	*7/1/2021*	*Updated Exec Summ,Sec 2.1*

Electric Storm

GENERAL INFORMATION

Requested Spend Amount	$6,000,000 annually
Requested Spend Time Period	Ongoing program
Requesting Organization/Department	Operations
Business Case Owner | Sponsor	David Howell | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The Electric Storm Business Case (BC) is focused on restoring Avista’s transmission, substation, and distribution systems (damaged plant) into serviceable condition during a weather storm event or other natural disasters where assets are damaged. These events are random and often occur with short notice. This business case funds a rapid response to unexpected damages, so customer outages are minimized. The business case provides funds for replacing poles, cross arms, conductor, transformers, and other defined retirement units damaged during storm events. The damage can be due to high winds, heavy ice and snow loads, lightning strikes, flooding, or wildfires. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers.

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 primary driver for the Electric Storm BC is **Failed Plant and Operations**. The work is a key component to minimizing customer outage times and contributes to Avista’s reliability indices like SAFI and CAIDI. The secondary driver for this business case is **Customer Service Quality and Reliability**.

Benefits to Customers
This business case allows funding for a rapid response to unexpected damages and service interruptions so customer outage times are minimized. The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. The Electric Storm BC is to fund a rapid response to unexpected damages and outages, so customer outages are minimized. If this business case is not funded the costs to restoring power to our customers will be absorbed by another business case. The needed work will continue to occur.

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 primary measure that will be used to determine success is outage duration including other reliability measures such as Avista's reliability indices like SAFI and CAIDI. These measures will demonstrate the impact of the work charged to this business case.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

N/A

Option	Capital Cost	Start	Complete
Unadjusted Average - Includes all MED costs; subject to more volatiility in funding needs in the year	*10,700,000 annually*	*Continuous Program*	
Adjusted Average - Excludes very large MED costs; less volatility in funding needs in the year	*6,000,000 annually*	*Continuous Program*	
Minimum Funding - Excludes all MED costs; additional funding needed in the year as MEDs occur	*4,000,000 annually*	*Continuous Program*	

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The annual budget amount is determined based on the historical average rate of capital restoration work.

Electric Storm

Figure 1 shows the historical costs (2015-2020) for the distribution/transmission storm business case. From 2015-2020, the average annual cost for capital storm response was $10.7 million dollars, with a range of $3.6MM (2018) to $28.2MM (2015). 2015 experienced an anomaly with a historic 100-year windstorm event. 2020 hosted 7 MED's. Consequently, 2015 and 2020 results are excluded from the calculation for the proposed funding level. The average spend 2016-2019 is 5.5MM. This includes some MED activity of comparatively minor restoration impact during these years. Excluding all MED costs, the average spend 2016-2019 is $4M. Already in 2021, May YTD the spend is 10.5M. Our proposed funding for 2022-2026 is $6M per year. Further funding for significant MED's will be requested as needed.

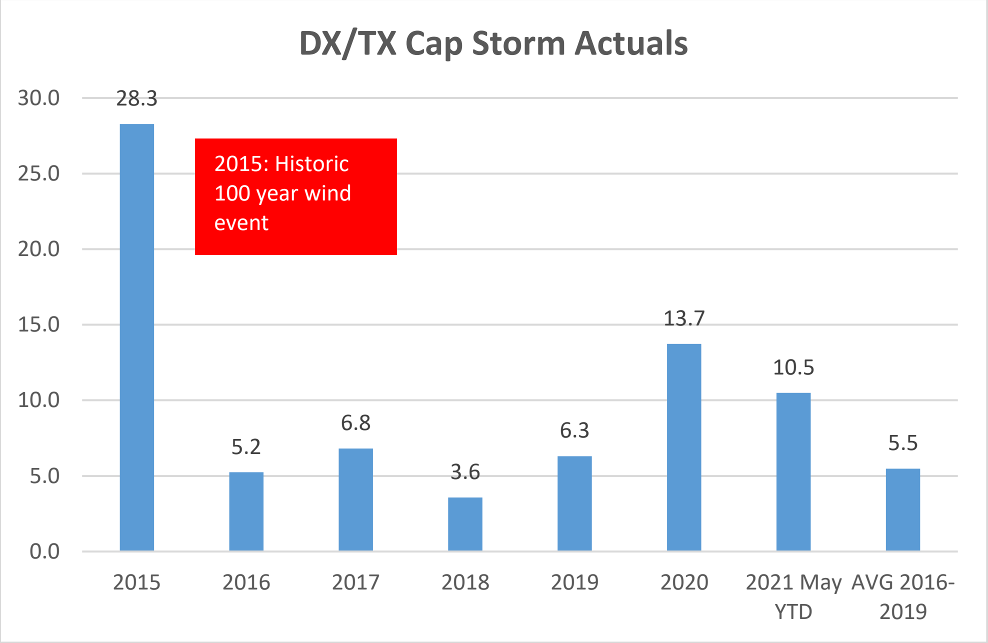


Figure 1: Storm Historical Costs

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 requested capital cost amount will be spent as needed, driven by customer outages as a result of a weather storm or natural disaster event. Historical spend is an indication of future spend.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Work under this business case occurs when repair is needed to facilities that are damaged during weather storm events or natural disasters. Depending on the severity and the duration of the specific outages, various business functions and processes may be impacted. Impacted areas can affect one office area or multiple Avista service territories.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The alternative to this business case request is not funding. 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 will have to be repaired, regardless of funding.

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. spend, and transfers to plant by year.

Weather storm events or natural disasters are a continuous risk. Work will occur as needed as a result of damaged facilities related to these events. Many times, multiple events may occur within one year in different office areas. Past data shows there has not been a year where a storm has not happened. Since this is often emergency work, assets become used and useful and transferred to plant immediately.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The Electric Storm business case aligns with the company's strategic goal of **Safe and Reliable Infrastructure**. The work is a key component to minimizing customer outage times and thus contributes to Avista's reliability indices like SAFI and CAIDI.

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

The importance of quickly replacing damaged facilities is vital to providing reliable service to our customers. The Electric Storm BC is to fund a rapid response to unexpected damages caused by weather storm events or natural disasters, so customer outage times are minimized. If this business case is not funded, the costs to restore power to our customers will be absorbed by a different business case, as the work will need to occur.

The YTD spend is tracked and reviewed each month during the Electric Operations Roundtable (ORT) meetings. The ORT reviews monthly spend and manages any additional funds requests.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The Electric Storm work is overseen by the local area operations engineers and area construction managers. In the event of larger scale storms or natural disasters, like the historical storm event in November 2015, a formal Incident Command System (ICS) is created to manage the resources needed to respond. Leaders will declare Emergency Operating Procedures (EOP) and Stakeholders from every area of the company are involved on safely restoring power to our electric customers.

2.8.2 Identify any related Business Cases

N/A

3.1 Steering Committee or Advisory Group Information

The Electric Storm work is overseen by the local area operations engineers and area construction managers. The work is unplanned and non-specific in nature but occurs regularly. In the event of larger scale storms or natural disasters, like the historical storm event in November 2015, a formal Incident Command System (ICS) is created to manage the resources needed to respond. Other large events are managed through an EOP with the Director of Operations.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance in place over the business case is set by the Operations Roundtable (ORT) group, which sets forecasted budgets, monitors the incurred costs and submits any additional funds requests as needed. Electric Storm work is overseen by the local area operations engineers and area construction managers.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision making, prioritization and change requests will be documented and monitored though the Operations Roundtable (ORT).

Electric Storm

The undersigned acknowledge they have reviewed the ***Electric Storms 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: David Howell Date: 1/3/22
Print Name: David Howell
Title: Director of Operations
Role: Business Case Owner

Signature: David Howell Date: 1/3/22
Print Name: David Howell
Title: Director of Operations
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Joint Use Projects

EXECUTIVE SUMMARY

Joint Use is the regulated use of utility poles and other structures by 3rd party telcommunications companies in order for them to provide their services to the customers we have in common. Avista licenses 76 unique entities that are attached to over 150,000 poles across Avista’s service territory and is required by federal, state and local laws to allow non discriminatory access to those assets. Even though this relationship is mandated by law, and is compliance driven, Avista agrees that this practice provides a direct benefit to our customers who desire those services.

Part of this requirement includes the obligation of Avista to replace infrastructure to taller stronger structures in order to accommodate or “make ready” those facilities for new attachments. This make ready work falls under capital expense and Avista is allowed to recover the actual costs from the requesting attacher. Avista is also allowed to recover a portion of the cost of replacing & maintaining shared infrastructure via a regulated yearly pole rental fee. Avista would face potential regulatory and or civil legal action if timelines and obligations are not met due to a lack of funding.The outcome of these actions could result in significant financial loss and penalties.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Stephen Schulte*	*Initial draft of original business case*	*6/302020*	

Joint Use Projects

GENERAL INFORMATION

Requested Spend Amount	$2.75m
Requested Spend Time Period	*Year to year*
Requesting Organization/Department	Operations/Joint Use
Business Case Owner | Sponsor	Stephen Schulte | David Howell
Sponsor Organization/Department	Operations/Joint Use
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

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? Access to safe and reliable utility infrastructure by third parties is not only a crucial element of the connected world in which we live but it is also mandated by regulators at the federal and state levels. Avista therefore has a duty to repair, replace or add infrastructure to accommodate those requests.

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 major drivers of this business case are the joint use and licensee's who request new pole attachments or who must upgrade their existing systems to meet the burgeoning and ever increasing demand for reliable and cost efficient communication needs. This has a direct benefit to not only Avista customers but Avista itself as we are also consumers of those same telecommunicaitons products. As mentioned previously fair and non discriminatory access to investor owned utility infrastructure is codified in Federal and State laws dating back to the Federal Telecommunicaitons Act of 1934 which laid the groundwork for the current system of asset sharing.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred. This work is needed currently and will be needed on an ongoing basis not only for existing wired telecommunication providers but for wireless providers who are more often than not reliant upon existing vertical utility assets to locate their equipment. These technologies are commonly referred to as 4G, 5G and LTE. The risk of not executing to meet these demands could result in regulatory action, resultant fines, and possible civil litigation that could far outweigh any short term savings. Damage to Avista's reputation and loss of customer trust could also result whose monetary costs are incalculable.

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.

Avista's joint use team utilizes several systems to track compliance and adherence to Federal, State and local regulations.On physical and practical level, success is more often realized when 2nd and 3rd parties construct their facilities, and follow up quality control is performed. Anectodally the joint use team has been approached by Avista customers who are very happy with their new telecommunication service that was made possible solely by the ability of the provider to attach their cables to Avista utility poles.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem. Tracking, invoicing and budget information is located on the joint use drive located on Avista network drive c01m289.

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.

[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, attach as supporting documentation)]

Option	Capital Cost	Start	Complete
Replace capital assets when requested	*2.75*	*Ongoing*	*Ongoing*
[Alternative #1]	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2]	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Current joint use capital business case amounts were derived from historic spend data coupled with projected activity that is based on trends seen in the joint use request tracking sheet. Avista receives a direct benefit of joint use related capital work by way of receiving a new asset at a decreased cost to rate payers. Due in large part to the dedication of fair and non discriminatory access to utility infrastructure, and the timeliness of completing requested capital make ready work.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

Joint Use Projects

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.** Given the current workload, and requests for capital asset replacement in support of joint use, current funding levels will be fully spent by the end of the budget year. Similar funding levels will be required on an ongoing basis with additional funding request sought as conditions warrant. The majority of assets being replaced should not add any additional operating costs beyond current levels such as wood pole test and treat, vegetation management etc.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[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. Additional workload resulting from increased joint use make ready could be experienced by several workgroups including but not limited to; Distribution Operations, Maximo, Real Estate, GIS, Asset Management, Transmission Operations.

[For example, how will the outcome of this business case impact other parts of the business?]

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative. No realistic alternatives exist nor were discussed. The only alternative would be to cease performing this work which would result in regulatory/legal action and customer dissatisfaction.

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. spend, and transfers to plant by year. This capital work related to this business case are ongoing and immediate. Transfers to plant occur on a monthly basis and the assets become used and useful immediately following physical construction.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization. The investment that is made in Avista’s physical plant to accommodate joint use telecommunications benefits the shared customer base of Avsita and the joint use providers. It places our customer at the center of our focus and helps Avista to provide a safe, reliable and cost effective services. It also helps to provide a safe working environment for all workers who require access to the electric distribution system.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

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. Joint Use requested capital make ready work is and will always be a prudent investment as the majority of assets that are being replaced are typically near the end of their life and Avista benefits from a newer, stronger structure. Pole replacements and new assets are typically the solution of last result and are only offered after careful consideration and review. High dollar cost replacements such as transmission pole receive addtitional scrutiny and review for appropriateness and cost effectiveness.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case. Avista Electric rate payers, Distribution operations, Distribution Engineering, Electric Design.

2.8.2 Identify any related Business Cases. The Joint Use business case was carved out of the Miscellaneous Capital Overhead Expense business case so that it could be more closely monitored and tracked.

[Including any business cases that may have been replaced by this business case]

3.1 Steering Committee or Advisory Group Information. The advisory group for this business case is the Operations Resource Team. It consists of the Manager of Operations Analytics (Julie Lee), Operations Analyst (Sherry Bentley), Facilitor of the Operations Round Table (Amy Jones), Manager of Distribution Engineering (Caesar Godinez), Operations Engineers (Brian Chain and Tim Figart), Operations Director (David Howell), and the Joint Use Program Adminstorator (Steve Schulte). Meetings are held at least once per quarter and as needed depending on necessary required changes or requests.

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

3.2 Provide and discuss the governance processes and people that will provide oversight. The business case spending levels are tracked and monitored by the Manager of Operations Analytics (Julie Lee) and Operations Analyst (Sherry Bentley) in Utility Accounting with monthly spend reporting to the Operations Director (David Howell).

3.3 How will decision-making, prioritization, and change requests be documented and monitored . Desicision for funding increases will be discussed during the Operations Resource Team meeting. If additional funding is deemed necessary then the business case owner Steve Schulte will complete the necessary documentation which will then be forwarded along to the Capital Planning Group for consideration. All documentation will be kept on file in the joint use server share in a ‘budget’ folder.

The undersigned acknowledge they have reviewed the Joint Use Projects 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:	Stephen Schulte	Date:	7/2/20
Print Name:	Stephen Schulte		
Title:	Joint Use Administrator		
Role:	Business Case Owner		

Signature:	David Howell	Date:	7/20/20
Print Name:	David Howell		
Title:	Director of Electric Operations		
Role:	Business Case Sponsor		

Joint Use Projects

Signature: ____________________ Date: __________

Print Name: ____________________

Title: ____________________

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

LED Street Lights

EXECUTIVE SUMMARY

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for vehicle driver and pedestrian safety. Avista manages streetlights for many local and state government entities to provide such street, sidewalk, and/or highway illumination for their streets by installing overhead streetlights. Upon light burn-out, lights are converted to LED. This work occurs in WA and ID.

Since this is a service our customer's pay for, they benefit from lighting service being restored upon light burn-out. Based on our historical burn-out rate, a spend of approximately $750,000 is needed. If this business case is not approved, failed lighting may not get replaced, resulting in customer dissatisfaction and increased public safety risks.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Amy Jones*	*Business Case Refresh Draft*	*7/2/2020*	

LED Street Lights

GENERAL INFORMATION

Requested Spend Amount	$750,000 annually
Requested Spend Time Period	Ongoing program
Requesting Organization/Department	Electric Operations
Business Case Owner | Sponsor	Amy Jones | David Howell
Sponsor Organization/Department	Operations
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for driver and pedestrian safety. Because they have an overhead distribution system in most urban areas, Avista provides a convenient streetlight service in almost every local and state government entity they serve, and manages the streetlights to provide street, sidewalk, and/or highway illumination.

Initially, the LED Change-Out Program was on an accelerated five-year schedule (2015 – 2019) to change-out all existing Avista owned streetlights to LED (Light Emitting Diode).

In the spring of 2018, upon Asset Management review, Avista executives, directors, and team leaders decided to adapt the replacement strategy to replace lights as they burned out.

Background:

The desire to begin the LED Change-Out Program in 2015 stems from a delay in energy savings, negative financial impacts, associated personal injury and property theft risks, and resource needs. Benefits are also found in the 2013 Asset Management Street Light Plan.

- Each 100 watt and 200-watt HPS light replaced will save 65 watts and 128 watts, respectively, per fixture. Once all the 100 watt and 200-watt HPS streetlights are replaced, the annual energy savings will be 9,903 MWH each year.
- With respect to the financial impacts of converting to LED streetlight technology, the customer internal rate of return is 8.46%, assuming the current cost of materials and life expectancy of the photocells and LED streetlight fixtures.
- From a public safety perspective, the consequence of converting to LED streetlights in lieu of replacing burned-out HPS bulbs shows a risk reduction of nearly eight times less for potential injury, a serious fatal accident, and property theft.
- Lastly, company resource demands are reduced after the initial conversion to LED technology. The average annual labor man-hours for current practices of changing burned-out HPS bulbs is estimated at 5,200 man-hours and 2,600 equipment hours, while the average man-hours required during the life of the LED fixtures are 3,200 man-hours and 1,800 equipment hours.

LED Street Lights

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 primary driver for converting overhead streetlights from High-Pressure Sodium (HPS) lights to LED lights is Asset Condition. By focusing on Asset Condition, there will be a significant improvement in energy savings, lighting quality for customers, and resource cost savings.

Secondly, converting streetlights to LED technology helps bring Avista in compliance with the Washington State Initiative 937 (or the Clean Energy Initiative), which ensures that at least fifteen percent of the electricity Washington state gets from major utilities comes from clean, renewable sources, and that Washington utilities undertake all cost-effective energy conservation measures. LED streetlight technology is part of the mentioned energy conservation measure.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for driver and pedestrian safety. Due to having an overhead distribution system in most urban areas, Avista provides a convenient streetlight service in almost every local and state government entity they serve, and manages the streetlights to provide street, sidewalk, and/or highway illumination.

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.

Measures to determine success include:

- Count of Replacements per year.
- Energy savings per year.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

- LED Replacement Analysis - One Pager
- 2013 Street Light Asset Management Plan - Final

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.

A lifetime material usage analysis on the HPS light fixtures estimated a mean time to failure (MTTF) for the various light fixture components. Table 1 shows the results for each streetlight component.

Component Groups	Material Usage Quantities	Replacement Ratio	MTTF (Years)
fuse	641	1%	84

Lamp	7,930	15%	7
photocell	5,151	10%	10
starter board	1,126	2%	48
streetlight fixture	683	2%	55

Table 1: 2011 Mean Time to Failure (MTTF) for HPS Streetlights

Upon completion of all streetlights changed out to LED fixtures, energy savings can be measured on an individual light fixture basis and then extrapolated to the entire system. Also, once all the streetlights are converted to LED, the number of service requests for streetlight burn-out should drop from the number of service requests prior to 2015.

Option	Capital Cost	Start	Complete
RECOMMENDED: Base Case (current practice of replacing burned-out HPS bulbs or replacing a fixture if broken)	$750,000	Ongoing program	
ALT #1: Optimized Case (planned replacement of HPS bulbs and photocells)	$1.67M	1/1/2015	Ongoing - 15-year cycle replacement
ALT #2: LED Case (change-out all fixtures to LED)	$2.32M	1/1/2021	5- or 10-years cycle bulb vs photocell.

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Three alternative cases were initially considered in the analysis of converting the streetlight to LED technology. **Base Case** replaces failed streetlight components only when they fail. The second case, called the **LED Case**, replaces the current HPS streetlights with new LED fixtures and implements a planned replacement at fifteen years for the fixture and photocell. At the time of the initial analysis, a fifteen-year replacement strategy proved more cost effective over the lifecycle than running LED lights to failure. Thirdly, the **Optimized Case** represents keeping the current HPS light fixtures and performing planned replacements of the bulbs and photocells at five-year cycles for the bulbs and ten-year cycle for the photocells.

In 2018, the replacement strategy moved from a five-year proactive program strategy to a run to failure (or “burn-out”) strategy. A run to failure strategy is the same as the Base Case mentioned above. By the end of 2018, nearly all Avista owned cobrahead streetlights had been converted to LED, with the majority of the remaining HPS streetlights in Idaho; mainly Coeur d Alene, Lewiston, Moscow, and Grangeville. However, thousands of customer area lights and thousands of decorative streetlights remained as HPS throughout the entire service territory and were being converted to LED on a burn-out replacement strategy. Because LED conversions of area lights and decorative streetlights have nearly the same cost savings and energy savings as the cobrahead streetlights, the program sponsors supported Asset Maintenance’s proposal to expand the scope of the program to include both types of lights. Starting in 2019, all area and decorative streetlights changed out will be charged to the LED Change Out Program.

Key assumptions made in the alternative's analysis are outlined below.

- The **Base Case** and the **Optimized Case**, because they propose using HPS fixtures, have the same failure characteristics shown in Table 2.

Table 1, HPS Light Component Failure Characteristics

Component	Initial Population Failure Rate (10%) by Year___	Initial Population Failure Rate (20%) by Year___	Mean Time to Failure (50% of the initial population will have failed by ____ Years)
100-Watt Bulb	3.4	4.4	6.7
Photocells	5.7	7.3	10.6
Starter Board	7.4	10.5	16.3

Table 2 shows the failure characteristics assumed for LED fixtures and components based on manufacturer's information and an assumed failure shape characteristic.

Table 2, Assumed LED Light Component Failure Curves

Component	Initial Population Failure Rate (10%) by Year___	Initial Population Failure Rate (20%) by Year___	Mean Time to Failure (50% of the initial population will have failed by ____ Years)
New Style Photocell	7.9	10.2	14.9
LED Light Fixture	12.1	15.5	22.6

For each of the cases, a model was created to help compare the risks, resource needs, potential energy savings, and financial impacts of each case. In the end, the **LED Case** will save customers money over the **Base Case**. While the **Optimized Case** provides a better financial return to our customers compared to both the Base Case and LED Case. The customers will still see savings over the life of the LED fixtures compared to today's practices in the Base Case and eliminate the need for 2.3 Megawatts of generation at night.

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 LED Change Out Program currently replaces LED lights upon failure (burn-out). Funding calculations are based on historical spend (2019 spend was approx. $678,000).

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 impacts of the LED Change-Out Program span across many departments at Avista. Operations is responsible for managing the work and executing the light change-outs in the field, primarily by Avista's servicemen and local reps. Avista's Operations Support Group (Mobile Dispatch) and EAM Technology are responsible for creating work orders for all change-outs and dispatching them to the field. The Customer and Shared Services department, particularity the Enterprise Systems – CC&B, is impacted by the project because the customer billing changes upon converting to LED light fixtures.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Three alternative cases were initially considered in the analysis of converting the streetlight to LED technology. **Base Case** replaces failed streetlight components only when they fail. The second case, called the **LED Case**, replaces the current HPS streetlights with new LED fixtures and implements a planned replacement at fifteen years for the fixture and photocell. The analysis noted that inside the new LED Case model, a fifteen-year replacement strategy proved more cost effective over the lifecycle than running LED lights to failure. Thirdly, the **Optimized Case** represents keeping the current HPS light fixtures and performing planned replacements of the bulbs and photocells at five-year cycles for the bulbs and ten-year cycle for the photocells

For each of the cases, a model was created to help compare the risks, resource needs, potential energy savings, and financial impacts of each case. In the end, the **LED Case** will save customers money over the **Base Case**. While the **Optimized Case** provides a better financial return to our customers compared to both the Base Case and LED Case. The customers will still see savings over the life of the LED fixtures compared to today's practices in the Base Case and eliminate the need for 2.3 Megawatts of generation at night.

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. spend, and transfers to plant by year.

This is an ongoing program that started in 2015.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The LED Change-Out Program is in alignment with the company's strategic vision of delivering reliable energy service and the choices that matter most to our customer's. As part of the program, infrastructure is replaced with longer lasting equipment. By providing more efficient equipment and quality lighting, this results in an energy savings and an increase in driver and pedestrian safety for our customers and communities we serve.

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

Any local or state government which has jurisdiction over streets and highways has an obligation to the general public they serve to provide acceptable illumination levels on their streets, sidewalks, and/or highways intended for driver and pedestrian safety. Due to having an overhead distribution system in most urban areas, Avista provides a convenient streetlight service in almost every local and state government entity they serve, and manages the streetlights to provide street, sidewalk, and/or highway illumination.

Results of this program include; significant improvement in energy savings, lighting quality for customers, and resource cost savings.

Secondly, converting streetlights to LED technology helps bring Avista in compliance with the Washington State Initiative 937 (or the Clean Energy Initiative), which ensures that at least fifteen percent of the electricity Washington state gets from major utilities comes from clean, renewable sources, and that Washington utilities undertake all cost-effective energy conservation measures. LED streetlight technology is part of the mentioned energy conservation measure.

The YTD spend is tracked and reviewed each month during the Electric Operations Roundtable (ORT) meetings. The ORT reviews monthly spend and manages any additional funds requests.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The LED Change-Out Program extends across multiple departments at Avista impacting them directly or indirectly. Each department identified as a stakeholder will nominate an engaged representative to act as the liaison between the program and their department. The department stakeholder representative will also take part to promote their department's interests in the business. Some internal departments include; Construction Services, Distribution Engineering, Warehouse and Investment Recovery, Supply Chain, External Communications, Mobile Dispatch, Enterprise Asset Management, Customer Enterprise Technology, and Regional Business Managers.

External stakeholders in the program include all state, county, and local agencies that have a streetlight account with Avista, as well as neighborhood councils, and local law enforcement agencies. All external stakeholders have a vested interest in the business because the streetlights illuminate their streets and sidewalks for the purpose of public safety.

2.8.2 Identify any related Business Cases

- **Grid Modernization:** With HPS lights changed out as they fail, Grid Modernization is likely to find and convert more HPS lights on selected feeders. (The System Wide DFMP says on page 34 that designers should change HPS lights when performing work in the supply space of a pole.)

3.1 Steering Committee or Advisory Group Information

The ORT acts as the advisory group for the LED Change Out Program.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance in place over the business case is set by the Operations Roundtable (ORT) group, which sets forecasted budgets, monitors the incurred costs and submits any additional funds requests as needed. LED Change Out Program work is overseen by the local area operations engineers and area construction managers**.**

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision making, prioritization and change requests will be documented and monitored though the Operations Roundtable (ORT).

The undersigned acknowledge they have reviewed the **LED Street Lights** 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: Amy Jones Date: 12/27/2021

Print Name: Amy Jones

LED Street Lights

Title: Asset Maintenance Business Analyst

Role: Business Case Owner

Signature: David Howell Date: 8/2/20

Print Name: David Howell

Title: Director of Operations

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Meter Minor Blanket

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high-level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

The meter minor blanket is used to charge the labor associated with new electric meter installations in Washington and Idaho due to the replacement of failed plant (meters) that can no longer gather or communicate accurate consumption data.

The Meter Minor Blanket Business Case is driven by tariff requirements that mandate Avista's obligation to serve existing customer load within our franchised area. Annual spending is approximately $250k per year.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*David Howell*	*Copy and update from 2017 business case*	*11/3/21*	
2.0				

Meter Minor Blanket

GENERAL INFORMATION

Requested Spend Amount	$250k
Requested Spend Time Period	1 year – Reoccurring annually
Requesting Organization/Department	Z08/Electric Meter Shop
Business Case Owner | Sponsor	Geena Duczek | David Howell
Sponsor Organization/Department	A50/ Electric Operations
Phase	Execution
Category	Program
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

The meter minor blanket is used to charge the labor associated with new electric meter installations in Washington and Idaho due to the replacement of failed plant (meters) that can no longer gather or communicate accurate consumption data. Failed plant is a result of various reasons including but not limited to, age, weather/environmental damage, hardware failure, or radio communication failures.

A meter must be installed as soon as possible to accurately capture customer energy consumption data. For this reason, Avista must sustain a continuous stock of each electric meter type and budget the required labor to install these meters.

The Meter Minor Blanket Business Case is driven by tariff requirements that mandate Avista's obligation to serve existing customer load within our franchised area.

1.1 What is the current or potential problem that is being addressed?

Replacement of failed electric meters

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 Driver – Failed Plant. It is necessary to have an operating meter to properly bill our customers and provide customers benefits in areas with AMI (Automatic Meter Reading).

Meter Minor Blanket

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

The work is required, when there is a failed meter, to properly measure and charge customers for electric energy services.

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.

Electric meters are approved by the commission to monitor and charge customers for usage as well as provide customer benefits related to AMI services.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The historical rate of labor and material costs related to meter replacement following a failure is approximately $250k/yr.

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.

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, attach as supporting documentation)]

Option	Capital Cost	Start	Complete
Replace the meter in kind	*$250k*	*01 2021*	*Ongoing*
[Alternative #1]	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2]	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Request is based on historical trends related to meter failures.

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.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

Director Offset - N/A – Replacement of failed plant.

Indirect Offset – Replacement of an older asset with a newer asset. Potential for an extended life.

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 replacement of failed meters supports the billing department to enable them to properly bill customers for usage.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Refurbish and repair inhouse - As Avista's population of digital meters grows and the mechanical meter population shrinks the less viable this option becomes. This is because digital meters require special equipment and training to repair, which is not available to our technicians. Also, of note is that mechanical meters are no longer manufactured by our meter vendors because they have moved to the digital market. It is very rare for our technicians to remove a mechanical meter from the field because of failure. The majority, if not all, of the meter failures we experience each year are from the digital meter families.

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.

This business case is a program that is ongoing each year. Transfers to plant occur monthly.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This work is required to ensure Avista properly bills our customers for electric energy consumption.

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

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The meter minor blanket business case is reviewed as part of the Operations Round Table (ORT) capital project steering committee monthly.

3.2 Provide and discuss the governance processes and people that will provide oversight.

The manager of the electric meter shop is responsible for director oversight of the business case and to ensure project charges are appropriate. The overall business case performance is the responsibility of the Electric Operations Director and administered through the Operations Round Table capital project steering committee.

3.3 How will decision-making, prioritization, and change requests be documented and monitored.

Changes to the process to manage the business cased will be documented within this business case.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Meter Minor Blanket busines 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: Geena Duczek Date: 11/3/21
Print Name: Geena Duczek
Title:
Role: Business Case Owner

Signature: David Howell Date: 11/3/21
Print Name: David Howell
Title: Electric Operations Director
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Growth Business Case

EXECUTIVE SUMMARY

Avista defines these investments as "customer requests for new service connections, line extensions, transmission interconnections, or system reinforcements to serve a single large customer." We have often in the past referred to new service connects as "growth," as in growth in the number of customers, however, these investments are beyond the control of the Company, and as such they do not reflect a plan or strategy on the part of Avista. Responding quickly to these customer requests is a requirement of providing utility service. Typical projects include installing electric facilities in a new housing or commercial development, installing or replacing electric meters, or adding street or area lights per a request from an individual customer, a city, or county agency. As would be expected, fluctuation in the number of new customer connections is largely dependent on local economic conditions both in the housing and business sectors. New customers are served for electric in WA and ID and gas in WA, ID, and OR.

Both connects forecast and 12-month rolling Cost Per Service information are used to calculate costs directly related to providing service to customers. Electric and Gas devices are also included in this business case - Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of the Meters, Transformers, and ERTs are used as replacements for Wood Pole Management, and Periodic Meter Changes, for example. The costs are allocated based on an estimate of how many devices of each type will be used for replacement, rather than new connects.

Growth Business Case Funds request:

ELEC & GAS	2022	2023	2024	2025	2026
Connects Forecast: Res & Comm	12,404	11,079	11,105	11,198	11,109
Extensions, Services	57,236,575	52,303,821	52,423,509	52,855,517	52,443,093
Lighting	2,119,067	2,182,639	2,248,118	2,315,561	2,385,028
Meters & Devices	5,449,239	5,318,044	5,131,301	5,197,450	5,233,388
Transformers & Network Protectors	8,510,394	7,544,517	7,569,018	7,632,452	7,563,661
Business Case Total	**73,315,274**	**67,349,021**	**67,371,946**	**68,000,979**	**67,625,170**

The 5 yr average annual spend for this business case has been around $73M. Requests for service are variable in number and in cost, sometimes requiring significant investment for system reinforcements such as gas reg stations and electric distribution infrastructure. This funds request is based on ordinary expectation as supported by forecast and input from electric and gas operations engineers.
For 2022, there are updated impacts to Growth costs, see 2.1 for more detail.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Julie Lee*	*Initial draft of business case*	*6/26/20*	
Final	*Julie Lee*	*Final version of business case*	*7/31/2020*	
Draft	*Julie Lee*	*Draft version of business case*	*7/9/2021*	*Exec summary, Sec 2.1,2.2 updated*

Growth Business Case

GENERAL INFORMATION

Requested Spend Amount	$344M
Requested Spend Time Period	5 years
Requesting Organization/Department	Energy Delivery
Business Case Owner | Sponsor	David Howell | Heather Rosentrater
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Mandatory
Driver	Customer Requested

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The New Revenue – Growth Business Case is driven by tariff requirements that mandate obligation to serve new customer load when requested within our franchised area. Growth is also seen as a method to spread costs over a wider customer base, keeping rate pressure lower than would otherwise be experienced.

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

Customer Requested: The New Revenue – Growth Business Case serves as support of several focus areas in Avista. We seek to serve the interests of our customers, in a safe and responsible manner, while strengthening the financial performance of the utility. Our growth contributes to strong communities, ongoing value to our customers, and the device portion of the business case keeps our system safe and reliable.

All new customers on Avista's system are benefitted by this business case. In addition, all customers who have their metering or regulation changed, or who have transformers replaced, benefit from this business case.

Transmission Interconnects:

- Periodically, Avista receives requests from 3rd party generation customers seeking interconnection on our Transmission facilities. Two types of customers seek service on our system:
    - First, those who want to wheel on our Transmission system. For this type of customer, Avista receives Transmission revenue for wheeling service. These customers are classified as New Revenue, as the construction costs are offset by ongoing revenues much like new retail customers.
    - The second category of generators are those that sell their output directly to Avista under PURPA contracts. Their output is contained in Avista's gross margin calculation as power supply costs.
- For the first class of customer, a financial analysis shall be performed, as justification for the construction costs to be included as New Revenue – Growth, and the capital so constructed shall be treated as growth for ratemaking purposes.
- PURPA customers' facilities shall be constructed under our existing non-revenue programs.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Avista is required to serve appropriate new load, complying with our Certificate of Convenience and Necessity, and as part of our Obligation to Serve.

The New Revenue – Growth Business Case will provide funds for connecting new Electric and Gas customers in accordance with our filed tariffs in each state.

Our obligation to serve, mandates that we must extend service to new customers in our franchised service areas. We do not currently have an alternative to serving new customers. All projects are subject to our Line Extension Tariffs, filed with each State Utility Commission.

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.

We periodically review and update the line extension tariffs to ensure we are not creating excessive rate pressure in connecting new customers.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

Option	Capital Cost	Start	Complete
Serve new customer load, and purchase appropriate devices	$67M-$73M per year	01 2022	12 9999
No other alternatives allowed under current tariff	$M	MM YYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

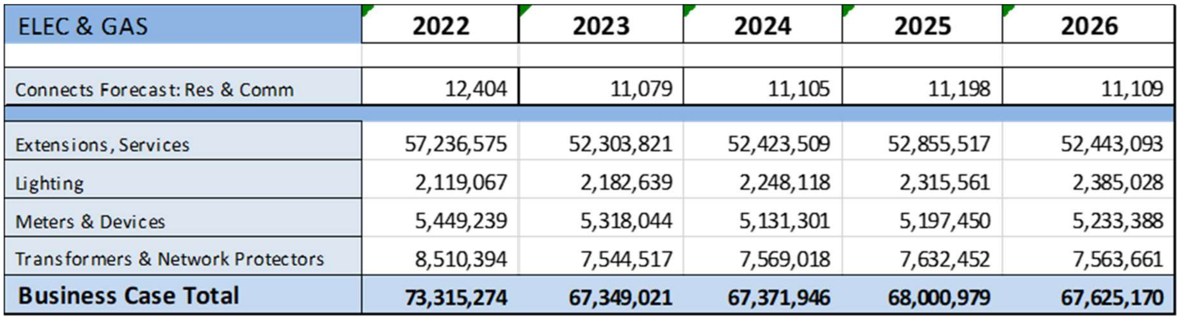
Avista uses a rolling 12-month Cost Per New Service spreadsheet to measure ER1000, Electric New Revenue, and ER1001, Gas New Revenue spending. Device blankets are subject to demand for both new revenue and non-revenue installation and replacement.

Enclosed is a spreadsheet showing projected spend through 2026 with a breakout by Expenditure Request for the New Revenue – Growth Business Case. Connects forecast and 12 -month rolling Cost Per Service information are used. Electric and Gas devices are also included, such as Meters, Transformers, Gas Regulators, and ERTs (Encoder Receiver Transmitter). Many of the Meters, Transformers, and ERTs are used as replacements for Transformer Change Out Program, Wood Pole Management, and Periodic Meter Changes. These costs are allocated based on an estimate of how many devices of each type will be used for replacement, rather than new connects. Those splits are shown on the spending summary.

Impacts: Updated forecasts for elec and gas connects for 2022 are 13% higher than forecasted previously. Schedule 51 changes for WA Elec will result in less customer contributions going forward. Transformer costs are 30% higher than costs included previously.

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.

As requests for services and lighting are received, design and the subsequent execution processes begin immediately. Similarly, as the gas and electric meters, devices, and transformers needs are identified by program managers and engineers, the purchasing department will place orders.



ELEC & GAS	2022	2023	2024	2025	2026
Connects Forecast: Res & Comm	12,404	11,079	11,105	11,198	11,109
Extensions, Services	57,236,575	52,303,821	52,423,509	52,855,517	52,443,093
Lighting	2,119,067	2,182,639	2,248,118	2,315,561	2,385,028
Meters & Devices	5,449,239	5,318,044	5,131,301	5,197,450	5,233,388
Transformers & Network Protectors	8,510,394	7,544,517	7,569,018	7,632,452	7,563,661
Business Case Total	**73,315,274**	**67,349,021**	**67,371,946**	**68,000,979**	**67,625,170**

There are no offsets to O&M.

[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.

In some instances, providing a service may require build-up of distribution infrastructure to support customer load.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

In some instances, there may be alternative ways to serve a customer. Customer project coordinators and engineers determine the solution that best serves the customer while considering subsequent customers and Avista's infrastructure.

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. spend, and transfers to plant by year.

Work timeline is primarily driven by the request of the customer. The transfer to plant occurs monthly.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This business case is about connecting customers to Avista's facilities. The work directly reflects our focus area for customers as well as our mission statement."We must hold our customer's interests at the forefront of all our decisions" and "We improve our customer's lives through innovative energy solutions."

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

Providing service to customers upon request is mandated. As needed CPC's and engineers review requests to determine solutions that best meet the needs of the customer and Avista. These extraordinary requests lend themselves to more visibility and oversight.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

New customers. For meters, devices and transformers - program managers.

.

2.8.2 Identify any related Business Cases

3.1 Steering Committee or Advisory Group Information

The Energy Delivery Director Team assumes the role of advisory group for the New Revenue – Growth Business Case, with quarterly reporting to the Board of Directors through the Financial Planning & Analysis department. The appropriate extension and service tariffs are designed and updated by the Avista Rates Department, in cooperation with Construction Services, and the Financial Planning & Analysis department. All Customer Project Coordinators are trained regularly, by Rates and Finance, on tariff application.

3.2 Provide and discuss the governance processes and people that will provide oversight

For the Electric and Gas New Revenue ERs: Operations managers and directors receive monthly Cost of Service reports providing 12-month rolling average costs for the construction areas. This allows for review of trending of costs for decision-making regarding processes and resources.

For the Metering and Devices ERs: Monthly Capital ER and project results reports are distributed. These provide updated variance information facilitating oversight by the Electric Meter Shop and Gas Engineering department.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

This business case consists of many separate requests, primarily independent of each other. Requests for services and extensions are supported by work order documentation. Extensions over $100k are assigned a specific project number to allow for more visible management awareness. Should the forecast for new connects or devices or the average cost of service significantly change from budget, the Capital Planning Group will be notified as to the new spending forecast.

The undersigned acknowledge they have reviewed the Growth 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: David Howell David Howell Date: 7/9/21
Print Name: David Howell
Title:
Role: Business Case Owner

Signature: Heather Rosentrater Heather Rosentrater Date: 10-10-21
Print Name: Heather Rosentrater
Title:
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Primary URD Cable Replacement 2017

1 GENERAL INFORMATION

Requested Spend Amount	$1,000,000
Requesting Organization/Department	Asset Maintenance
Business Case Owner	Cody Krogh
Business Case Sponsor	Bryan Cox
Sponsor Organization/Department	Asset Maintenance
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Cable condition and outage information is collected and analyzed by Asset Management. This information is reviewed with Asset Maintenance to establish an effective construction plan that prioritizes work based on faults and number of customer impacted. Asset Maintenance then collaborates with Electric Operations to coordinate the work. Asset Maintenance tracks the work budget, scope, and schedule.

2 BUSINESS PROBLEM

The primary driver for the Underground Residential Development (URD) Cable Replacement Program is to improve system reliability by removing URD cable with a high failure rate. The other driver is to reduce O&M costs related to responding to customer outages caused by the failed cable.

This work is needed to complete the replacement of the un-jacketed first generation underground primary distribution cable referred to as URD cable. This first generation URD cable was installed from 1971 to 1982. There was over 6,000,000 feet of URD cable installed during this time period. Subsequent to installation the URD cable began to experience an increasing failure rate. From 1992 to 2005 the cable failure rates quadrupled from 2 faults to 8 faults per 10 miles of cable. The faults reached a peak of 238 annual failures in 2007. Increased capital funding to replace this URD cable from 2005 through 2009 helped stabilize the failure rates. Continued funding and replacement of the cable has enabled a downward trend in failures as shown below in table 1. Cable installed after 1982 has not shown the high failure rate.

This work is required to continue to reduce primary URD cable failures and increase reliability. Historically there have been over 200 cable faults per year. The average cost to respond to a fault in 2015 was about $3000 per event due to the challenging nature of the work to locate and repair the cable underground. The estimated remaining pre-1982 cable is around 1,000,000 circuit feet.

Primary URD Cable Replacement 2017

The tables below demonstrate the effectiveness of this program to reduce faults and outage expenses through the replacement of the defective cable. The trend of cable faults and expenses decrease over time as the older cable is removed from the system.

Table1: URD Cable Replacement Results

KPI Description	Projected URD Cable - Primary OMT Events	Actual URD Cable - Primary OMT Events	Projected Number of Feet Replaced	Actual Number of Feet Replaced
2009	143	136	178,000	213,000
2010	119	93	178,000	217,883
2011	94	95	178,000	225,823
2012	70	72	178,000	117,247
2013	45	93	0	35,874
2014	45	88	0	35,515
2015	45	64	0	24,155

Table 2: URD Cable Replacement Cost Impact

Metric Description	Projected Avoided Outage Benefit due to URD Cable - Pri Caused Outages	Actual Avoided Outage Benefit due to URD Cable - Pri Outages
2009	$1,038,613	$1,056,113
2010	$1,228,275	$1,295,225
2011	$1,368,561	$1,352,648
2012	$1,516,159	$1,481,504
2013	$1,744,539	$1,494,738
2014	$1,898,311	$1,580,378
2015	$1,997,052	$1,720,020

Reference:

Electric Distribution System, 2016 Asset Management Plan

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
[Recommended Solution] Continue to Replace	$1M	04 2017	12 2037

The Primary URD Cable Replacement Program requires design resources and construction labor to complete the field work. There is also some analytics/engineering to identify remaining cable segment locations. Given the projected low capital spend level, the majority of the construction labor will be performed by Avista Crews. Contract crews are typically used to plow in the cable, bore conduit or trench and install conduit in the trench. Avista crews then pull the cable into the conduit and complete the installation.

The Do Nothing approach presents significant reliability risk and added O&M cost. The historic positive results from the URD cable replacement program shown above in section two provide strong justification for continuing the current funding plan.

Over 6,000,000 feet of URD was installed before 1982. Programmed replacement of the problem cable has been on-going at varying funding levels. The estimated remaining pre-1982 cable is around 1,000,000 circuit feet. At the current proposed funding rate of $1M per year this program is planned for the next 20 years. Reduced funding would extend this time and result in additional outages and O&M expenses.

The URD Cable Replacement Program aligns with Avista's strategic vision by increasing reliability to the electric distribution system. Safe and Reliable infrastructure is the focus area for this program.

The projected annual capital spend of $1M per year is reasonable based on the realized reduction in faults from previous work and this spend level enables continued replacement of the high failure rate cable. Repair of the cable has not shown to be cost effective because the cable typically faults in another location.

Avista customers will be positively impacted by this program by realizing fewer outages from the URD cable failure. This results in improved system reliability. Avista electric operations is positively impacted through converting this work to planned work that enables more efficient use of labor. It also reduces O&M expenses. Asset Management is responsible for tracking URD cable outages from Outage Management Tool (OMT) and tracking replacement locations and cost. The Asset Maintenance group is responsible for identifying cable segments and managing the coordination of work.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Primary URD Cable Replacement and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 4-14-2017
Print Name: Cody Krogh
Title: Mgr Asset Maintenance
Role: Business Case Owner

Signature: Date: 4-17-17
Print Name: Bryan Cox
Title: Sr Dir of HR Operations
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Cody Krogh	4/14/2017	Bryan Cox	4/14/2017	Initial version

Template Version: 03/07/2017

Protection System Upgrades for PRC-002

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

NERC reliability standard PRC-002-2 defines the disturbance monitoring and reporting requirements to have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances. The methodology of Attachment A of the NERC standard was performed to identify the affected buses within the Avista BES. The Protection Systems must be capable of recording electrical quantities for each BES Elements it owns connected to the BES buses identified.

Non-compliance can carry a fine of up to a million dollars per day based on severity. This business case is important to customers because it allows analysis of system faults for the BES that can lead to continued stability and reliability of the electric system.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2016-07

Cost of Solution: $12,000,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Randy Spacek	Initial Version	7/11/2017	Initial Version
2.0	Glenn Madden	Revised to remove DRAFT watermark	5/28/2019	
3.0	Karen Kusel / Glenn Madden	Update to 2020 Template	06/2020	

Protection System Upgrades for PRC-002

GENERAL INFORMATION

Requested Spend Amount	$12,000,000
Requested Spend Time Period	5 Years
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Josh Diluciano
Sponsor Organization/Department	Electrical Engineering
Phase	Execution
Category	Project
Driver	Mandatory & Compliance

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]

NERC reliability standard PRC-002-2 defines the disturbance monitoring and reporting requirements to have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances. The methodology of Attachment A of the NERC standard was performed to identify the affected buses within the Avista BES. The Protection Systems must be capable of recording electrical quantities for each BES Elements it owns connected to the BES buses identified.

The present Protection Systems are either electromechanical or first generation relays not capable of meeting the NERC PRC-002-2 standard requirements of fault recording. The scope of the project is to upgrade the existing Protection Systems on various 230 kV and 115kV terminals to Fault Recording (FR) capability per PRC- 002 requirements at Beacon, Boulder, Rathdrum, Cabinet Gorge, North Lewiston, Lolo, Pine Creek, Shawnee, and Westside Substations. Implementation is a phased approach with 50% compliaint within 4 years and fully compliant within 6 years of the effective date 7/1/16. The total number of affected terminals is 49.

Non-compliance can carry a fine of up to a million dollars per day based on severity.

1.1 What is the current or potential problem that is being addressed?

PRC-002-2 went into effect on 7/1/2016, we have six years to bring our protection system into compliance with this updated standard.

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

Mandatory & Compliance is the main driver for this project. But this will also allow more information to be collected to facilitate analysis of BES disturbances.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Avista is required to comply with PRC-002 by July 1, 2022.

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.

System Planning Assessments, Relay & Protection Design Reporting for PRC-002.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

NERC Reliability Standard PRC-002-2

NERC Project 200711 Disturbance Monitoring:

DL-2007-11_DM_Imp_Plan_2014Sep01_clean

PRC-002 Bus Fault Summary & Anaylsis 2016.xlsx

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 present Protection Systems are either electromechanical or first generation relays not capable of meeting the NERC PRC-002-2 standard requirements of fault recording.

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, attach as supporting documentation)]

The Protection System upgrade of 49 terminals impacts the resources of Engineering and GPSS over a 5 year period. The NERC standard requires compliance by specific dates. By missing the compliance date set forth by NERC, Avista not only risks monetary penalties based on severity but reputational damage as well.

Cost estimates per terminal from previous Protection System upgrades at a total installed cost of $150k.

Protection System upgrades is the preffered solution. The relay replacement will not only provide the recording capability but will improve system reliability, reduce maintenance and support other NERC standard requirements (PRC-023, PRC-004).

In the past, Avista has attempted to put in a single digital fault recorder that complicated the wiring and CT circuits within a station. All recorders have since been removed.

Option	Capital Cost	Start	Complete
Upgrade Protection Systems	$4.86M	02 2017	10 2022
Do Nothing	$0M		
Installation of a digital recorder on each BES bus to provide the SER and FR data.			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

Since this is a compliance mandate, we also looked at other standards and relay options.

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.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[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.]

2020 - $3,200,000

2021 – $5,420,000

2022 – $2,480,000

2023 – $150,000

O&M costs may be reduced with this equipment replacement.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

Delay of the other projects due to resource scarcity.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See Section 2.0 for alternative discussion.

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. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Project is currently underway, construction is in progress at multiple sites and will conclude in 2022 and closeout of project will occur in 2023. Transfers to plant are completed when the work at each location is completed.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

Fault recording at substations enables root cause analysis, which can lead to improved reliability. Additionally the work is mandatory from NERC.

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

NERC required projects are vetted through NERC as to the viability of requiring the work to be done and the associated benefit. The investment is likely to result in improved reliability to the BES.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

The Engineering Roundtable process is used to identify projects requmng Transmission, Substation, or Protection (TS&P) engineering support. The committee is responsible to track TS&P project requests, facilitate prioritization of TS&P capital projects across Engineering, Operations, and Planning), and to ensure projects are completed consistent with the company's mission and corporate strategies.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Protection System Upgrades for PRC-002 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: Glenn J Madden Date: 12-23-20
Print Name: Glenn Madden
Title: Manager, Substation Engineering
Role: Business Case Owner

Signature: Date: 1/5/2021
Print Name: Josh DiLuciano
Title: Director, Electrical Engineering
Role: Business Case Sponsor

Signature: Damon Fisher Date: 1/5/2021
Print Name: Damon Fisher
Title: Principle Engineer
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Exh. HLR-2

New Saddle Mountain 230/115kV Station Phase 1 Integration

1 GENERAL INFORMATION

Requested Spend Amount	$38,000,000
Requesting Organization/Department	Transmission Planning
Business Case Owner	Scott Waples
Business Case Sponsor	Heather Rosentrater
Sponsor Organization/Department	T&D
Category	Project
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

- Ken Sweigart – Manager, Substation Engineering
- Project Engineer/Project Manager – Brian Chain

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

2 BUSINESS PROBLEM

In the fall of 2013, Grant employees contacted Avista System Planning about performance issues within Grant's system that are exacerbated by Avista's load in the Othello area. The issue was escalated to Columbia Grid through the Regional Planning process. It was identified through this process and Avista System Planning that the system performance analysis indeed indicates an inability of the System to meet the performance requirements P1, P2 and P6 categories in Table 1 of NERC TPL-001-4 in current heavy summer scenarios, and P6 categories in heavy winter scenarios.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Alt 1: Status Quo			
Alt 2: Build new 115kV Transmission Line			
Alt 3: Close "Star" Points			
Alt 4: Install Generation			
Alt 5: Build Saddle Mountain 230/115kV Substation Phase 1 Project with associated support projects	*$38M*	*2017*	*2021*

Alternative 1:

This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations.

New Saddle Mountain 230/115kV Station Phase 1 Integration

Alternative 2:

This alternative is not recommended as it does not mitigate the low voltage issues in the Othello area.

Alternative 3:

This alternative is not recommended due to its high cost. It is anticipated that $75M of reconductoring would be needed to mitigate any potential violations comparable to the preferred alternative.

Alternative 4:

This alternative is not recommended due to its high financial costs, the potential for must run operation and the lead time on this project will be well beyond the time this project is needed per NERC requirements.

Alternative 5:

This alternative is the most cost effective option considered and provides enough voltage support and capacity into the area for the next 50 years. This alternative mitigates all identified deficiencies in the Othello area documented in the 2016 Planning Annual Assessment. This alternative is the best solution for the long term.

Solution:

Alternative 5: The scope recommended consists of two phases:

PHASE 1:

1) Construct a 3 – position 230 kV double bus double breaker arrangement with space for 2 future positions at the line crossing of the Walla Walla – Wanapum 230 kV and Benton – Othello 115 kV transmission lines.
2) Construct a 3 position 115 kV breaker and a half arrangement with space for 3 future positions.
3) Install 250 MVA Transformer
4) Rebuild entire 8.28 miles of Othello – Warden No.1 115 kV line with minimum 205 MVA capacity
5) Rebuild 2.88 miles of Othello – Warden No. 2 115 kV line with minimum 205 MVA capacity

COST: $38M

IN SERVICE: 12/31/2020

PHASE 2: See Associated Phase 2 BC Narrative

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Saddle Mountain 230/115kV Station (New) Integration 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: Date: 8/11/2017
Print Name: Scott Waples
Title: Director of Planning & AM
Role: Business Case Owner

Signature: Date: 8/14/17
Print Name: Heather Rosentrater
Title: VP Energy Delivery
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*<Author name>*	*mm/dd/yy*	*<name>*	*mm/dd/yy*	*Initial version*

Template Version: 03/07/2017

Saddle Mountain 230-115kV Station (New) Integration Project Phase 2

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

Large commercial customers in the Othello area have continued to expand their businesses. The business expansion has created demands on the electric system that are not able to be adequately backed up with the reliability that they deserve. Meeting the increased load demands are possible, but equipment failures could cause outages that would be time consuming and difficult to restore quickly.

This business case would replace the Othello City substation with a new station having 2-30MVA transformers. The business case also includes substancial upgrades to the transmission system in the area to integrate the new Othello City substation with the new Saddle Mountain substation. This business case is important to customers so that they can continue to have the reliability of the electric system that they have become accustomed to receiving.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-64

Cost of Solution: $25,650,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Unknown	Initial Version	2017	
2.0	Karen Kusel / Glenn Madden	Update to 202 Template	6/2020	

Saddle Mountain 230-115kV Station (New) Integration Project Phase 2

GENERAL INFORMATION

Requested Spend Amount	$11,000,000
Requested Spend Time Period	4 Years
Requesting Organization/Department	Transmission / System Planning
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Planning
Category	Project
Driver	Mandatory & Compliance

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]

This business case would replace the Othello City substation with a new station having 2-30MVA transformers. The business case also includes substancial upgrades to the transmission system in the area to integrate the new Othello City substation with the new Saddle Mountain substation.

1.1 What is the current or potential problem that is being addressed?

There are performance issues in the Othello area, it is also difficult to maintain the equipment at the Othello 115kV Substation due to load deam on all feeders.

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

Mandatory & Compliance are the main priority of this project due to TPL-001-4 non-compliance at this time. There are also Performance & Capacity issues that will be remedied with this project. Overall, this rebuild will relieve load and outage concerns for large commercial customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Due to increased load in the area, we are risking large customer outages due to equipment failure.

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.

System Planning Assessments.

Saddle Mountain 230-115kV Station (New) Integration Project Phase 2

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

Project Report: Saddle Mountain Study.pdf

2016 Avista System Planning Assessment Report (Page 56)

Othello City Substation Area Load Analysis

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.

System Planning Assessments.

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, attach as supporting documentation)]

Alternative 1: Status Quo. This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations.

Alternative 2: Build new 115kV Transmission Line. This alternative is not recommended as it does not mitigate the low voltage issues in the Othello area.

Alternative 3: Close “Star” Points. This alternative is not recommended due to its high cost. It is anticipated that $75M of reconductoring would be needed to mitigate any potential violations comparable to the preferred alternative.

Alternative 4: Install Generation. This alternative is not recommended due to its high financial costs, the potential for must run operation and the lead time on this project will be well beyond the time this project is needed per NERC requirements.

Alternative 5: Build Saddle Mountain 230/115kV Substation Phase 2 Project with associated support projects. This alternative is the most cost effective option considered and provides enough voltage support and capacity into the area for the next 50 years. This alternative mitigates all identified deficianencies in the Othello area documentes in the 2016 Planning Annual Assessment. This alternative is the best solution for the long term.

Phase 1: See Associated Phase 1 Business Case Narrative.

Phase 2:

1) Rebuild Othello Substation to 115kV Ring Bus with 5 positions.
2) Build new Transmission line from Saddle Mountain 115kV to Othello Substation 115kV.

This alternative is the most cost effective option considered and provides enough voltage support and capacity into the area for the next 50 years. This alternative mitigates all identified deficiencies in the Othello area documented in the 2016 Planning Annual Assessment. This alternative is the best solution for the long term.

Saddle Mountain 230-115kV Station (New) Integration Project Phase 2

Option	Capital Cost	Start	Complete
Recommended Solution: Build Saddle Mountain 230/115kV Substation Phase 2 Project with associated support projects	$11M	01 2020	12 2021
Alternative 1: Status Quo	$0M		
Alternative 2: Build new 115kV Transmission Line			
Alternative 3: Close "Star" Points	$75M		
Alternative 4: Install Generation			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

System Planning Assessments, previous outage information.

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.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[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.]

2020 - $2,500,000

2021 – $24,650,000

2022 – $1,000,000

2022 – Closeout

O&M will be comparible to before this project.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system in the Othello area.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See Section 2.0 for alternative discussion.

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. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Design work was begun in 2020, construction will be completed by 2022 and closout may continue into 2023. Transfers to plant will occur when the new station is commissioned and energized.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

This project will alleviate concerns regarding large customer outages and will provide the ability to maintain major substation equipment.

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

The scope for the project, which is to increase transformation in the Othello area as well as to increase reliability by creating the switching station is the least cost option. Adhering to the scope and project objectives will be reviewed regularly by the project team including the project engineer and the project manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Saddle Mountain 230/115kV Station (New) Integration Project Phase 1 was completed in 2020.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

The Engineering Roundtable initially is designated as the Steering Committee for this project, with a more project-specific Steering Committee to be potentially identified at a later date.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Saddle Mountain 230-115kV Station (New) Integration Project Phase 2 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: Glenn J Madden Date: 1-3-2022
Print Name: Glenn Madden
Title: Manager, Substation Engineering
Role: Business Case Owner

Signature: Date: 1/3/2022
Print Name: Josh DiLuciano
Title: Director, Electrical Engineering
Role: Business Case Sponsor

Signature: Damon Fisher Date: 1/4/2022
Print Name: Damon Fisher
Title: Principle Engineer
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

SCADA - SOO and BuCC

EXECUTIVE SUMMARY

This business case provides for replacement of existing technology, as well as for deployment of new applications and technology as required to address expanding regulatory and business requirements. This program (Supervisory Control and Data Acquisition - System Operations Office and Backup Control Center) replaces and upgrades existing electric and gas control center telecommunications and computing systems as they reach the end of their useful lives, require increased capacity, or cannot accommodate necessary equipment upgrades due to existing constraints. Some system upgrades may be necessitated by other requirements, including NERC reliability standards, federal gas standards, system growth, and external projects (e.g. Smart Grid). The customers who benefit are all electric and gas residential, commercial, and industrial customers (CD.AA).

The estimated costs for the upcoming five years are $4.35M. The amount requested is based partially upon historical spending needs, and partially on known upcoming major projects. Within the program's yearly authorized spend amount, specific budgetary items to be implemented are determined based on asset condition, life-cycle management, technology enhancements, and requests by affected stakeholders including System Operations, Distribution Operations, and Power Supply.

There are multiple risks if this program is not adequately funded. The clearest risk would be to public and personnel safety. The control systems supported by this business case provide real-time visibility, situational awareness, and control of Avista's electric and gas systems. Degradation of these capabilities due to lack of capacity, capability, or aging systems would present increased safety risk. Additionally there is significant compliance risk. These control systems provide the capabilities required to achieve compliance with numerous reliability standards and requirements. For the electrical system these include the NERC standards BAL, COM, CIP, EOP, INT, PER, PRC, TOP, and VAR. For the gas system these include the PHMSA "Pipeline Safety: Control Room Management/Human Factors" rule (49 CFR Parts 192 and 195.) The expenditure of these funds is necessary to operate Avista's electric and gas systems in a safe, reliable, and compliant manner.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Craig Figart	Initial draft of original business case	07.1.2020	
0.2	Craig N Figart	Draft version of 2020 business case	07.17.2020	Updated Executive Summary
1.0	Craig N Figart	Final version of 2020 business case	09.21.2020	Based on Magruder input.
2.0	Jeremiah Webster	formatting to keep the fonts consistent, removed some of the blue help text, and deleted the comments	12.15.2020	
3.0	Craig N Figart	Updated per $350k capital funding increase for 2021 due to EMS upgrade	07.05.2021	

SCADA - SOO and BuCC

GENERAL INFORMATION

Requested Spend Amount	$4.35M
Requested Spend Time Period	5 years
Requesting Organization/Department	T&D - SCADA/EMS/DMS - System Operations
Business Case Owner | Sponsor	Craig N Figart | Mike Magruder
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

In order to effectively operate the Transmission & Distribution (T&D) Systems, sufficient business and computing hardware and software is necessary. This business case provides for replacement of existing technology in alignment with manufacturer product roadmaps for application and technology lifecycles, as well as for deployment of new applications and technology as required to address expanding regulatory and business requirements. Technology continues to change and T&D Systems continue to incorporate improved technology.

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

Asset Condition is the major driver of the business case. Other drivers are Customer Service Quality & Reliability and Performance & Capacity. This business case is crucial in a key aspect of Our Vision; “Delivering reliable energy service…” It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

There are multiple risks if this program is not adequately funded. The clearest risk would be to public and personnel safety. The control systems supported by this business case provide real-time visibility, situational awareness, and control of Avista’s electric and gas systems. Degradation of these capabilities due to lack of capacity, capability, or aging systems would present increased safety risk. Additionally there is significant compliance risk.

These control systems provide the capabilities required to achieve compliance with numerous reliability standards and requirements. For the electrical system these include the NERC standards BAL, COM, CIP, EOP, INT, PER, PRC, TOP, and VAR. For the gas system these include the PHMSA “Pipeline Safety: Control Room Management/Human Factors” rule (49 CFR Parts 192 and 195.)

SCADA - SOO and BuCC

The expenditure of these funds is necessary to operate Avista's electric and gas systems in a safe, reliable, and compliant manner.

In addition to the risks related to public and personnel safety, compliance risk would be increased without this investment. Non-compliant operational capabilities and practices would result in negative audit findings, significant financial penalties, and litigation expenses. Obsolete equipment would remain in service until failure. Additional capacity for growth may or may not be suitable for required expansions to meet other needs (e.g. Regulatory, Smart Grid.)

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.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Not applicable

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.

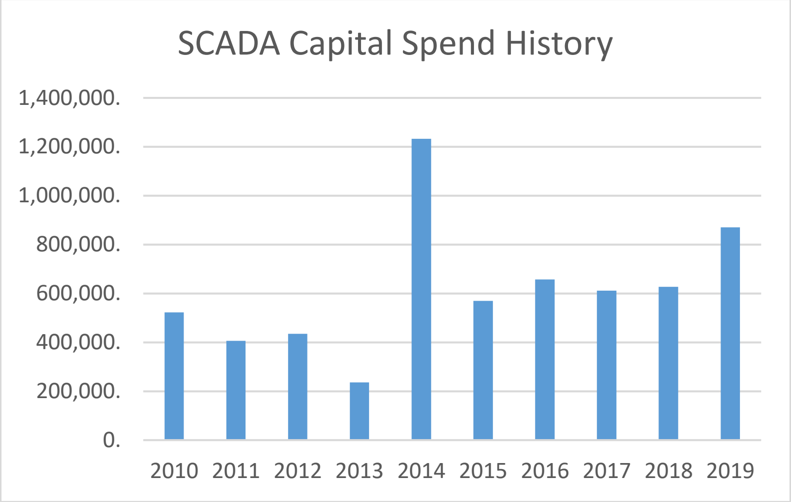
Not applicable

Option	Capital Cost	Start	Complete
Do nothing	$0		
Fully Funded "SCADA – SOO and BuCC" business case	$1.35M	01/2021	12/2021

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The below SCADA Capital Spend History chart provides a visual for past expenditures. On average, SCADA spends around $700,000 per year. This five year capital request was prepared using this $700,000 average number for the last three years. The first two years include significantly larger requests, however, most notably due to the EMS Upgrade project that we will be wrapped up in 2021. The last EMS Upgrade occurred in 2014 as can be seen in the chart below.

SCADA - SOO and BuCC



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 five year capital request of $4.35M is comprised of $1.35M in 2021. The most significant project driving SCADA's typical capital project expenses above the average $700,000 is the estimated $300,000 additional capital required to complete the EMS Upgrade project.

The completion of this EMS Upgrade project will eliminate $11k annually in O&M costs associated with extended operating system support.

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 EMS upgrade project is required to be completed in order to upgrade hardware and software that is no longer supported. The EMS upgrade project will also better accommodate operation under the Energy Imbalance Market.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Not applicable

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. spend, and transfers to plant by year.

This is a continuous program. Work is started and completed throughout each year, and in some cases, such as major upgrades, spans multiple years. Technology continues to change and T&D Systems continue to incorporate improved technology.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This business case is crucial in a key aspect of Our Vision; “Delivering reliable energy service…” It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service.

SCADA - SOO and BuCC

This business case is key in accomplishing the Our Focus item of "Safe & Reliable Infrastructure." Providing remote monitor and control capabilities to operators is essential in achieving "optimum life-cycle performance - safely, reliably, and at a fair price."

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

Further justification of the need of this business case is listed below.

- There are numerous mandates in effect which compel these expenditures, numerous NERC Standards, and PHMSA's Control Room Management rule, in particular (49 CFR Parts 192 and 195).
- There is no practical risk mitigation should we fail to meet these requirements.
- This is a continuous program. Work is started and completed throughout each year, and in some cases, such as major upgrades, spans multiple years.
- This business case is crucial in a key aspect of Our Vision; "Delivering reliable energy service…" It is essential in providing sufficient control center technology tools, situational awareness, and monitor/control capabilities to achieve reliable energy service.
- This business case is key in accomplishing the Our Focus item of "Safe & Reliable Infrastructure." Providing remote monitor and control capabilities to operators is essential in achieving "optimum life-cycle performance - safely, reliably, and at a fair price."
- The amount requested is based partially upon historical spending needs, and partially on known upcoming major projects.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

- Our Stakeholders include:
  - Operations
    - System Operators
    - Power Schedulers
    - Distribution Operators
    - Gas Controllers
    - Energy Accounting & Risk Management
    - Neighboring utility control centers
    - RC West Reliability Coordinator
  - Technicians
    - Protection/Control/Metering Technicians
    - Telecommunication Technicians
  - Engineering

        - Protection/Integration Engineering
        - Substation Engineering
        - Generation Engineering
        - Distribution System Operations
    - Enterprise Technology
        - Oracle Database Administrators
        - Security Engineering
        - Network Engineering
        - Network Operations

2.8.2 Identify any related Business Cases

Not applicable

3.1 Steering Committee or Advisory Group Information

The steering committee for this business case is made of the following:

- Director of System Operations and Planning
- Manager of Energy Management Systems (EMS/DMS)
- Senior System Operations Project Manager

3.2 Provide and discuss the governance processes and people that will provide oversight

The steering committee provides governance and oversight of this business case. The Manager of EMS/DMS has monthly meetings scheduled within the Energy Management Systems group to track progress of the various capital projects that comprise the total business case.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision-making, prioritization, and change requests at the individual capital project level are taken care of within the Energy Management Systems group under manager supervision. Any need for substantial change requests to capital projects that would deviate from the original Capital Project Request (CPR) are documented and submitted to Project Accounting as a revised CPR. If the sum total of all SCADA capital projects is expected to exceed the approved Business Case funding, then a Business Case Change Request must be approved by the Steering Committee and submitted to Project Accounting.

The undersigned acknowledge they have reviewed the Business Case Justification Narrative – SCADA -SOO and BuCC – 2020 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: Craig N Figart Date: Jul 5, 2021
Print Name: Craig N Figart
Title: Manager of SCADA/EMS
Role: Business Case Owner

Signature: Michael A Magruder Date: July 8, 2021
Print Name: Mike Magruder
Title: Energy Delivery Director, System Operations & Planning
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

AVISTA

Capital Investment Business Case

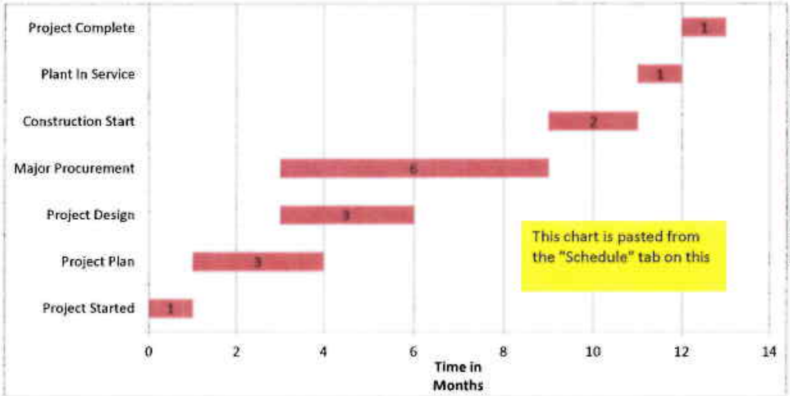
Investment Name:	**Spokane Smart Circuit**
Requested Amount	**$22M**
Duration/Timeframe	5 Year Project
Dept.., Area:	Business Process Improvement
Owner:	Heather Rosentrater
Sponsor:	Don Kopczynski
Category:	Project
Mandate/Reg. Reference:	n/a

Assessments:	
Financial:	High - Exceeds 12% CIRR
Strategic:	Reliability & Capacity
Operational:	Operations improved beyond current levels
Business Risk:	ERM Reduction >10 and <= 15
Project/Program Risk:	High certainty around cost, schedule and resources
Assessment Score:	116.1666667

		Cost Summary - Increase/(Decrease)			
Recommend Project Description:	**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
At this time the utility's distribution system has little real time information and is unable to respond to dynamic loading and faulted conditions very quickly. This project will install a Distribution Management System that will allow real time system information to be used to control the distribution system. Intelligent end devices such as capacitor banks, air switches and reclosers will be installed and will provide sensing and control of the distribution circuits. Substations control and communication equipment will be upgraded to allow for the control and aggregation of field data. A wireless mesh network will be installed to provide backhaul from end devices to the substations. The project will automate distribution equipment on 58 feeders and in 14 substations.	Distribution Automation reducing system losses and outage impacts	$ 22,000,000	$ -	$ -	8

			Cost Summary - Increase/(Decrease)			
Alternatives:		**Performance**	**Capital Cost**	**O&M Cost**	**Other Costs**	**Business Risk Score**
Status Quo:	System continues to operate as today.	n/a	$ -	$ -	$ -	20
Alternative 1: Brief name of alternative (if applicable)	A distribution automation system is implemented on 14 substations and 59 of the distribution circuits.	Distribution Automation reducing system losses	$ 22,000,000	$ -	$ -	8
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Timeline



This chart is pasted from the "Schedule" tab on this

Construction Cash Flows (CWIP)

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ 18,781,582	$ -	$ -	$ 18,781,582
2012	$ 2,146,190	$ -	$ -	$ 2,146,190
2013	$ 1,072,228	$ -	$ -	$ 814,228
2014	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -
2016	$ -	$ -	$ -	$ -
2017	$ -	$ -	$ -	$ -
2018	$ -	$ -	$ -	$ -
Future	$ -	$ -	$ -	$ -
Total	$ 22,000,000	$ -	$ -	$ 21,742,000

Milestones (high level targets)

October-09	Project Started	June-12	Plant In Service	mm/dd/yy	open
October-09	Project Plan	March-13	Project Complete	mm/dd/yy	open
June-10	Project Design	mm/dd/yy	open	mm/dd/yy	open
October-09	Major Procurement	mm/dd/yy	open		
October-09	Construction Start	mm/dd/yy	open		

Milestones should be general. In some cases it may be as simple as project start, project complete. Use your judgement on project progress so that progress can be measured.

Associated Ers (list all applicable):	Current ER 2529
Mandate Excerpt (if applicable):	I937 renewable portfolio standard

Additional Justifications:

This project is in conjunction with a federal smart grid grant. Avista is contractually obligated to complete the scope of work and could risk up to $20M in lost grant moneys.

AVISTA

Capital Investment Business Case

Resources Requirements: *(request forms and approvals attached)*

Internal Labor Availability: ☐ Low Probability ☐ Medium Probability ☑ High Probablity
Contract Labor: ☑ YES ☐ NO

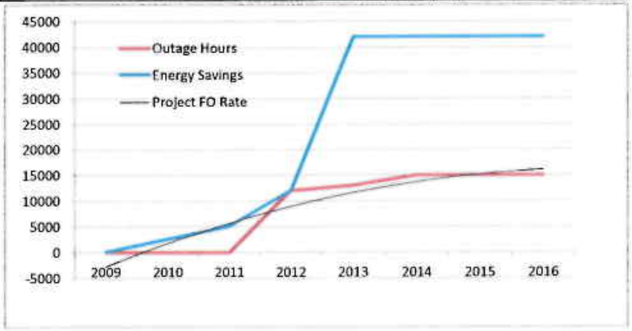
Enterprise Tech: ☐ YES - attach form ☑ NO or Not Required
Facilities: ☐ YES - attach form ☑ NO or Not Required
Capital Tools: ☐ YES - attach form ☑ NO or Not Required
Fleet: ☐ YES - attach form ☑ NO or Not Required

Check the appropriate box. The internal and contract labor boxes should be checked to indicate if the resource owners have been contacted and to provide a general sense of how likely staff will be provided (this does not require a firm committment).

Key Performance Indicator(s)

Expected Performance Improvements

KPI Measure:	Avoided Outage Hours
	Reduced system losses (MWh/Yr)



Prepared signature John Gibson

Reviewed signature
Director/Manager

Other Party Review signature
(if necessary)
Director/Manager

This space is to be used for photographs, charts, or other data that may be useful in evaulating the project

To be completed by Capital Planning Group

Rationale for decision	Review Cycles 2012-2016	
	Date	**Template**

Printed: 01 02 2014
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Spokane Valley Transmission Reinforcement Project

EXECUTIVE SUMMARY

This section is reserved to provide a ***brief*** *description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

Local load growth, specifically at the local paper mill occurring in 2007 is a strong driver for a transmission system expansion in the Spokane Valley area. Additionally, there are NERC TPL-001-4 events not meeting performance requirements that are mitigated by completing the project. The worst performance issue mitigated by the completion of the project is the NERC TPL-001-4 category P2.4 event of an internal Breaker Fault (Bus-tie Breaker) on A717 at Boulder Station. System performance analysis indicates an inability of the System to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer Scenarios for the P2 contingency. An Operating Procedure to open Boulder A717 can be used to mitigate the system deficiencies. Portions of the project have been completed prior to 2016.

The remaining portions of the Spokane Valley Transmission Reinforcement project are constructing the Irvin Substation and rebuilding a portion of the Beacon – Boulder #2 115 kV Transmission Line. All system defeciencies are mitigated and the desired operational flexibility to serve large industrial customers is realized. This business case is important to customers because its completion likely allows customers to continue to receive electrical service with the reliability that they have grown accustom to receiving.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-48

Cost of Solution: $19,00,000 (includes completed projects) over $15 years

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	4/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	06/2020	

Spokane Valley Transmission Reinforcement Project

GENERAL INFORMATION

Requested Spend Amount	$6,800,000 (Remaining Projects)
Requested Spend Time Period	3 Years
Requesting Organization/Department	Transmission/System Planning
Business Case Owner | Sponsor	Glenn Madden | Josh Diluciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Project
Driver	Mandatory & Compliance

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]

Completion of this project is required to mitigate a NERC TPL-001-4 system deficiency. The transmission system in the Spokane Valley currently fails TPL-001-4(P2.4), which is an internal Breaker Fault (Bus-tie Breaker) on A717 at the Boulder Station. In addition the system fails the NERC TPL-001-4 P2 Contingency for the 2017 Heavy Summer Scenario. Completion of this project is required to ensure Avista maintains compliance with NERC regulations and Avista's planning documents.

1.1 What is the current or potential problem that is being addressed?

Being currently out of compliance of NERC TPL-001-4 and potential breaker faults which could lead to large customer outages.

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 major driver of the business case is Mandatory & Compliance. Completion of this project is required to ensure Avista maintains compliance with NERC regulations and Avista's planning documents.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

There are risks to the reliability of electric service with delays to the completion of this project.

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.

Future System Planning Assessments will show the BES improvements made by completing this project.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

2016 Avista System Planning Assessment.pdf

Irvin Project Final.pdf

IrvinvSubstationvProject - Rev C.pdf

SP-2009-03 Summary of Work - Irvin Project.pdf

SP-2011-07 2011 Spokane Valley Transmission Reinforcement.pdf

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.

Not Applicable.

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, attach as supporting documentation)]

Recommendation: Alternative 2, complete the Spokane Valley Transmission Reinforcement project. Remaining project scope includes the following:

Construct the Irvin Station terminating the Beacon – Boulder #1 and #2, Irvin – IEP, and Irvin – Opportunity 115 kV transmission lines as a breaker and a half configuration: $5 million.

Rebuild the existing Beacon – Boulder #2 115 kV Transmission Line from Beacon to Millwood to 795 ACSS conductor: $2 million.

Alternative 1: Status Quo

This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations.

Alternative 2: Revert to before the CDA Reconfiguration Project

Revert the system to the condition prior to the Coeur d'Alene Reconfiguration Project creating the Boulder-Rathdrum and Post Falls –Ramsey 115 kV transmission lines. Operational concerns will present themselves specifically with a P2.1 planned outage followed by a forced Pl event in the Coeur d'Alene area. (The P2.1 and Pl event combination is not a TPL-001-4 event.) Operational flexibility constrained by large industrial customers will continue to persist.

Option	Capital Cost	Start	Complete
Complete Project (Irvin Substation and BEA-BLD #2 115kv Line Rebuild)	$6.8M	01 2020	12 2021
Alt 1: Status Quo	$0M		
Alt 3: Revert to before the CDA Reconfiguration Project			

Spokane Valley Transmission Reinforcement Project

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

Load Growth, changes to compliance standards and System Planning Assessments were considered.

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.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[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.]

2020 - $3.9M

2021 - $2.9M

O&M will be reduced by replacing the transmission line which will help offset the cost of O&M of inspection and maintenance requirements of the substation and its equipment.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system in the Spokane Valley area.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Status Quo would possibly lead to NERC fines and large customer outages. Reverting to before the CDA Reconfiguration project would negate the benefits of having completed that project.

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. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Construction at Irvin Substation will continue in the Fall of 2020 and be complete in the Spring of 2021. The Beacon – Boulder #2 transmission rebuild will be completed in late 2021.

Transfers to Plant will occur as the substation and transmission line are deemed in-service and energized.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

This project will provide a solid foundation for customer reliability in the Spokane Valley.

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

The scope for the project, which is to increase reliability in the Spokane Valley by creating the switching station is the least cost option. Adhering to the scope and project objectives will be reviewed regularly by the project team including the project engineer and the project manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

- Glenn Madden - Manager, Substation Engineering
- Project Engineer/Project Manager (PE/PM)- Various

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

This project has been reviewed by the Engineering Roundtable.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and upcoming project.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site.

Exh. HLR-2

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Spokane Valley Transmission Reinforcement 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: Glenn J Madden Date: 1-3-2022
Print Name: Glenn Madden
Title: Manager, Substation Engineering
Role: Business Case Owner

Signature: Date: 1/4/2022
Print Name: Josh DiLuciano
Title: Director, Electrical Engineering
Role: Business Case Sponsor

Signature: Damon Fisher Date: 1/4/2022
Print Name: Damon Fisher
Title: Principle Engineer
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Substation – New Distribution Station Capacity Program

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

New distribution substations added to the system for load growth and reliability are critical to the long term operation of the system. As load demands, increase and customer expectations rise regarding reliability, incremental distribution substation capacity is required. This allows for improved operational flexibility, better system reliability, and easier routine maintenance scheduling as equipment is more easily taken out of service because load can be transferred.

Capacity on the electric system to be able to take components out of service on a planned basis so that maintenance or replacements can be made has reduced as load demands have increased. Having the right amount of backup capacity in each area is critical for the continued appropriate management of the electric system. This business case is important because through it, customers can likely continue to receive electric service at a level that they have grown accustom to receiving.

Service: ED – Electric Direct

Jurisdiction: Various. Each rebuild project has its own Jurisdiction.

Engineering Roundtable Request Number: Various. Each rebuild project has its own ERT Request.

2020 Expected Spend: $7,600,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	04/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	06/30/2020	

Substation – New Distribution Station Capacity Program

GENERAL INFORMATION

Requested Spend Amount	$6,000,000 per year
Requested Spend Time Period	On Going
Requesting Organization/Department	T&D
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Program
Driver	Performance & Capacity

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]

New distribution substations added to the system for load growth and reliability are critical to the long term operation of the system. As load demands, increase and customer expectations rise regarding reliability, incremental distribution substation capacity is required. This allows for improved operational flexibility, better system reliability, and easier routine maintenance scheduling as equipment is more easily taken out of service because load can be transferred.

1.1 What is the current or potential problem that is being addressed?

As load demands, increase and customer expectations rise regarding reliability, incremental distribution substation capacity is required.

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

Performance and Capacity – Increasing load on an aging electrical system. And the better the asset condition, the fewer equipment failures and possible customer outages there are.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This is a continuing effort to stay ahead of the curve to avoid reliability issues.

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.

System Planning Assessments and Studies.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

System Planning Assessments on System Planning Sharepoint site.

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.

Not Applicable.

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, attach as supporting documentation)]

This program adds new distribution substations to the system in order to serve new and growing load as well as for increased system reliability and operational flexibility. New substations under this program will require planning and operational studies, justifications, and approved Project Diagrams prior to funding.

Alternatives considered include:

Do Nothing: Maintain (to the best of our ability) all obsolete or end-of-life apparatus. Repair or replace equipment on emergency basis only. Some repairs would not be possible due to obsolescence. Considerably more, and longer, customer outages would result. Although there is zero Capital cost connected with keeping the status quo there are some associated O&M and other system sustainment costs.

Extension of distribution feeders from neighboring substations and increased capacity at those substations would be required at a minimum. The negative impact is most certainly reduced reliability and difficulty in long term maintenance and system operation. Increased liability would result.

Solution: Anticipated load growth requires the addition of two new substations per year over the 2017-2026 horizon

Option	Capital Cost	Start	Complete
Recommended Solution	$6M	Annually	Annually
Alternative #1: Do Nothing	$0		
Extend Existing Distribution Feeders			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

System Planning Assessments.

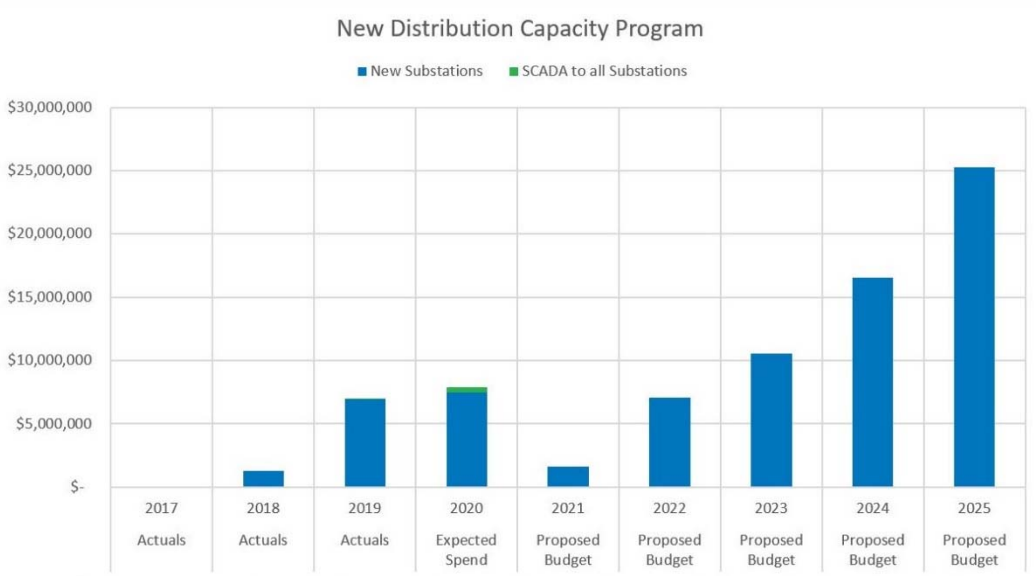
Substation – New Distribution Station Capacity Program

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.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[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.]

Below is a graph showing previous years actual spend on this Business Case, the Expected Spend for 2020 and budget requests for the future.



O&M will increase due to the addition of electric substation and associated transmission and distribution lines. This will include inspections and maintenance of equipment.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Status Quo – Obsolete equipment drives up maintenance costs and outage risks. Extending Distribution Feeders – higher risk of load issues and customer outages.

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. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

See graph above, Section 2.2. Transfers to plant will occur when a substation is in-service or energized. Adhering to project timelines will save capital carrying costs.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

These projects will help Avista stay ahead of the curve of load growth and equipment age to prevent customer outages.

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

Failure to adjust to load changes and customer needs will lead to equipment failures, customer outages and expensive emergency projects.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

- Glenn Madden - Manager, Substation Engineering
- Project Engineer/Project Manager (PE/PM) – Various

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

The Engineering Roundtable manages the prioritization of projects within this business case as supported by Asset Management studies and input from company subject matter experts. The Engineering Roundtable is comprised of representatives from the following departments: Asset Management, Compliance, System Planning, System Operations, Telecommunications, Transmission Contracts, Protection Engineering, Substation Engineering, Transmission Engineering, and Substation Support.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Substation – New Distribution Station Capacity 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: Glenn J Madden Date: 12-23-2020
Print Name: Glenn Madden
Title: Manager, Substation Engineering
Role: Business Case Owner

Signature: Date: JDD ~~1/5/2020~~ 1/5/2021
Print Name: Josh DiLuciano
Title: Director, Electrical Engineering
Role: Business Case Sponsor

Signature: Damon Fisher Date: 1/5/2021
Print Name: Damon Fisher
Title: Principle Engineer
Role: Steering/Advisory Committee Review

Substation – Station Rebuilds Program

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

Replacing and upgrading major substation apparatus and equipment as it approaches end of life or becomes obsolete is necessary to maintain safe and reliable operation of Avista's transmission and distribution systems. Rebuilding significant portions of stations may be necessary to accommodate the replacement of failing or obsolete equipment since new standard-use apparatus and equipment is often of higher capacity and newer technology and may need to meet updated equipment spacing and operating standards.

Failure to replace old 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. This Business Case is important for customers because it is critical toward Avista's ability to continue to provide the reliable electrical service that customers have grown accustom to receiving.

Service: ED – Electric Direct

Jurisdiction: Various. Each rebuild project has its own Jurisdiction.

Engineering Roundtable Request Number: Various. Each rebuild project has its own ERT Request.

2020 Expected Spend: $18,900,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	4/14/2017	
2.0	Jeff Schlect	Consolodation of capital maintenance and major rebuild business cases	5/19/2017	
3.0	Karen Kusel / Glenn Madden	Update to 2020 Template	6/30/2020	

Substation – Station Rebuilds Program

GENERAL INFORMATION

Requested Spend Amount	$20,000,000 per year
Requested Spend Time Period	On Going
Requesting Organization/Department	T&D – Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Program
Driver	Asset Condition

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]

Replacing and upgrading major substation apparatus and equipment as it approaches end of life or becomes obsolete is necessary to maintain safe and reliable operation of Avista's transmission and distribution systems. Rebuilding significant portions of stations may be necessary to accommodate the replacement of failing or obsolete equipment since new standard-use apparatus and equipment is often of higher capacity and newer technology and may need to meet updated equipment spacing and operating standards. 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).

Major apparatus include 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.

Failure to replace old 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.

1.1 What is the current or potential problem that is being addressed?

Aging apparatus and equipment plus changes in customer needs and compliance requirements.

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 major driver of the business case is Asset Condition. Good asset condition leads to fewer customer outages.

Substation – Station Rebuilds Program

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This is an on-going program to stay ahead of the curve of asset age and 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.

General age of all major substation equipment.

System Planning Assessments.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

System Planning Assessments, Maximo Work Orders.

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.

As of July 2020, here are samples of data we use to view asset information used to determine viable options for substation rebuilds.

Equipment Type	Average Manuf Year
Air Switch	2005
Breaker Recloser	2000
Circuit Switcher	1991
HV Circuit Breaker	1996
Power Transformer	1986
Switchgear Breaker	1985
Voltage Regulator	2002

Equipment Type	Oldest Mfg Yr and Substation
Air Switch	1930 - Leon Jct
Breaker Recloser	1924 - South Lewiston
Circuit Switcher	1968 - Osburn
HV Circuit Breaker	1952 - Sunset
Power Transformer	1946 - Garfield
Switchgear Breaker	1963 - Chester
Voltage Regulator	1960 - Bunker Hill

Location	Avg Age of Major Equipment
Coeur Shaft Mine 13kV	1961
Chester 115kV	1974
Rockford 115kV	1975
Post Falls 115kV	1977
Dry Gulch 115kV	1978
Wallace 115kV	1979
Metro 115kV	1979
South Lewiston 115kV	1980
Roxboro 115kV	1981
Leon Jct. 115kV	1981

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, attach as supporting documentation)]

The recommended approach is to replace station apparatus and equipment as needed due to asset condition and consider broader station rebuilds when the majority of assets in the impacted area of a station 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 degradation of reliability and mitigating the frequency and duration of outages due to equipment failure.

Option 1: Do nothing - Not recommended

Option 2: Maintain current funding level - Current spending on the Asset Condition risk category is $12.85 million annually. Project prioritization will be supported by Asset Management and substation subject matter experts for prioritization of work within this risk category. Project and funding levels will be reviewed on an annual basis.

Option 3: Reduce current Asset Condition capital improvements. Not recommended. May lead to a reduction in the level of reliability and or operating flexibility that can be achieved by the transmission and distribution systems.

Option	Capital Cost	Start	Complete
Maintain present level of Station Rebuilds	$20M	On Going	On Going
Alternate 1: Do nothing	$0M		
Alternate 2: Maintain minimum level of Station Rebuilds	$0-12M	-	

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*
-

Substation – Station Rebuilds Program

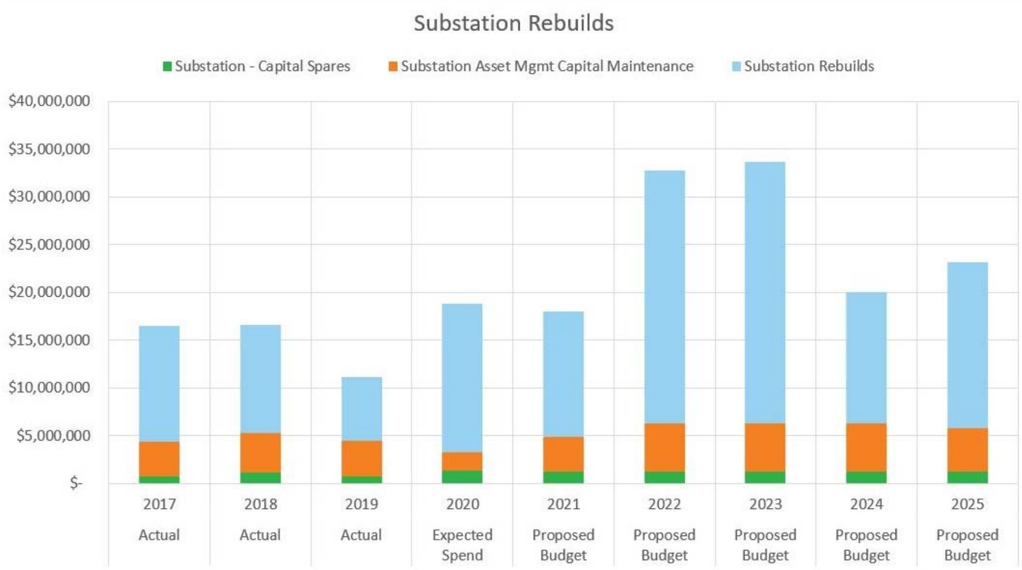
Reference key points from external documentation, list any addendums, attachments etc. System Planning Assessments and Asset Management information.

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.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[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.]

Ongoing improvements to the BES via substation rebuilds will result in system reliability, fewer customer outages and smaller O&M costs.



2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Reduce the numbers of capital improvements or Doing Nothing causes equipment to age and become obsolete and difficult to maintain.

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. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Ongoing average of two rebuilds per year with multiple projects being in various stages of design, construction and closeout.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

These projects will help Avista stay ahead of the curve of load growth and equipment age to prevent customer outages.

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

Customer outages are longer and larger when older equipment fails.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

The Engineering Roundtable manages the prioritization of projects within this business case as supported by Asset Management studies and input from company subject matter experts. The Engineering Roundtable is comprised of representatives from the following departments: Asset Management, Compliance, System Planning, System Operations, Telecommunications, Transmission Contracts, Protection Engineering, Substation Engineering, Transmission Engineering, and Substation Support.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Substation - Station Rebuild 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: Date: 12-23-2020
Print Name: Glenn Madden
Title: Manager, Substation Engineering
Role: Business Case Owner

Signature: Date: JDD ~~1/5/2020~~ 1/5/2021
Print Name: Josh DiLuciano
Title: Director, Electrical Engineering
Role: Business Case Sponsor

Signature: Damon Fisher *Damon Fisher* Date: 1/5/2021
Print Name: Damon Fisher
Title: Principle Engineer
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Transmission Minor Rebuild

EXECUTIVE SUMMARY

The Transmission Minor 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 Failed Plant and Asset Condition.

The implementation of this business case will be considered successful if these projects are all completed on an annual basis or the dates identified in the Engineering Roundtable Project List.

The Transmission Minor Rebuild Business Case covers the follow-up work to Wood Pole Inspections, Aerial Patrol inspections, and Ad Hoc ground inspections and Air Switch Replacements.

During routinely scheduled inspections, issues are discovered regarding the condition of assets, including items such as rotten poles, broken/split/rotten crossarms, broken conductor or ground/shield wire, and air switches that no longer operate safely or reliably.

The recommended solution is to correct the issues found by these inspections either in the same year, or within 1-2 years afterwards. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs an increased risk of system failures, customers outages, and wildfires. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North. An annual spend of $3,343,420 is needed to complete the mitigations as follows:

- *ER 2057, BI AMT12 and AMT13 ($1,613,420): Wood and Steel Pole Inspections (FAC-501-WECC-1, TMIP)*
- *ER 2057, BI XT902 ($1,500,000): Aerial and ground inspections (FAC-501-WECC-1, TMIP, and Ad Hoc)*
- *ER 2254, BI AMT10 ($230,000): Planned/unplanned replacements based on failure or upgrade needs*

The customer benefits from this Business Case through increased service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Daisy Drafter*	*Initial draft of original business case*	*4/15/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0				

Transmission Minor Rebuild

GENERAL INFORMATION

Requested Spend Amount	$16,717,100
Requested Spend Time Period	*5 years*
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Execution
Category	Program
Driver	Multiple (see Executive Summary)

1. BUSINESS PROBLEM

The Transmission Minor 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 Failed Plant and Asset Condition.

The Business Case also covers aerial, ground and Ad Hoc patrols intended to pro-actively replace structures and structure components as riak on near term failure. This work (BI XT902: $1.5M) in previous years was funded through the Operations Storms blanket Business Case.

1.1 What is the current or potential problem that is being addressed? *Avoidance of failure conditions; that, if left unaddressed in the near-term (<1-2 years) will result in an increased risk of system failures, customers outages, and wildfires*

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 *Mandatory & Compliance, combined with Failed Plant and Asset Condition: Customer benefits by having a Transmission System in compliance with Federal Standards, and one where identified near-term failure risks are proacitively addressed.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred *Unlike Asset Management studies and analysis that develop long-term facility failure models, the inspection protocols associated with this Business Case identify asset problems; that, if left unaddressed, will lead to near-term catastrophic structural failures.*

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.

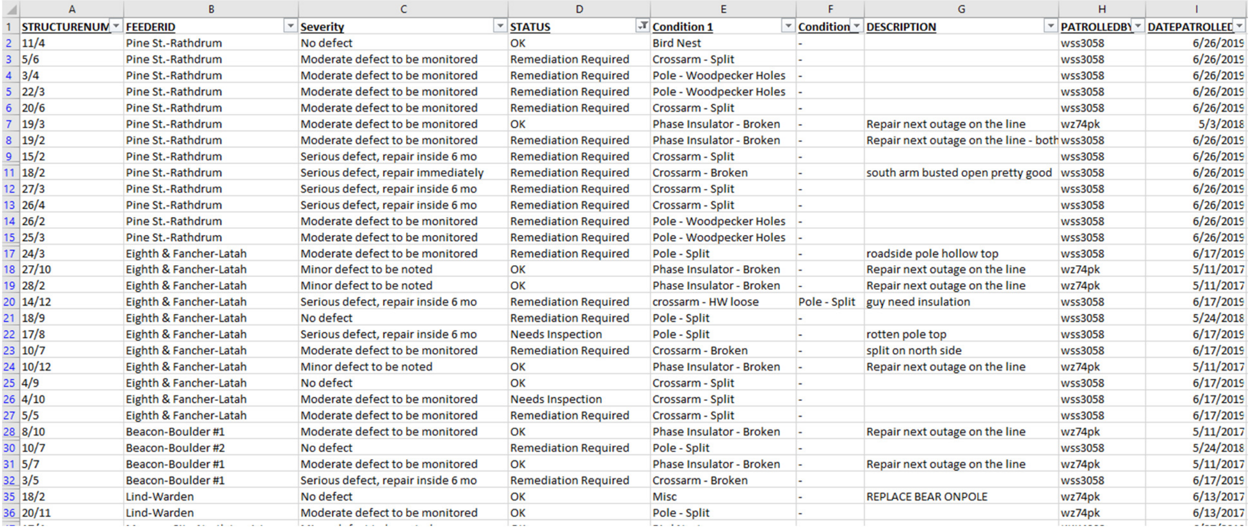
As-Built confirmation of mitigation measures.

1.5 Supplemental Information

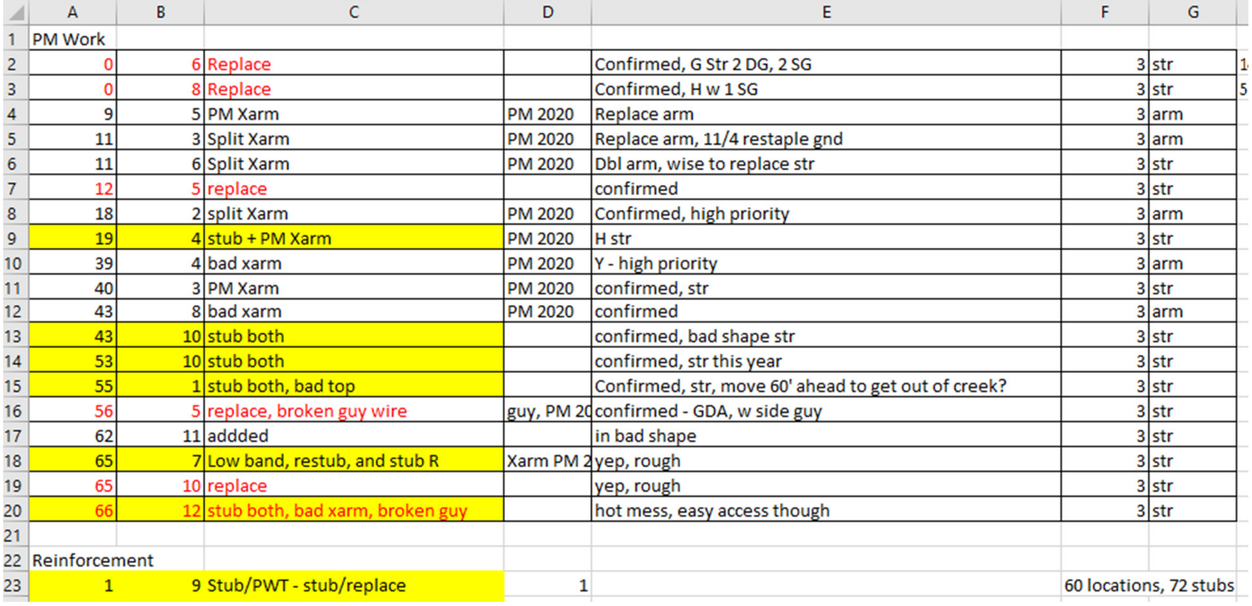
1.5.1 Please reference and summarize any studies that support the problem

Asset Maintenance Wood Pole Management annual inspection reports
Transmission Line Design annual aerial patrol reports
Ad hoc inspections and or real-time notifications from area offices

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.



	A	B	C	D	E	F	G	H	I
1	STRUCTURENUM	FEEDERID	Severity	STATUS	Condition 1	Condition	DESCRIPTION	PATROLLEDBY	DATEPATROLLED
2	11/4	Pine St.-Rathdrum	No defect	OK	Bird Nest	-		wss3058	6/26/2019
3	5/6	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
4	3/4	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
5	22/3	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
6	20/6	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
7	19/3	Pine St.-Rathdrum	Moderate defect to be monitored	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/3/2018
8	19/2	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Phase Insulator - Broken	-	Repair next outage on the line - both	wss3058	6/26/2019
9	15/2	Pine St.-Rathdrum	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
11	18/2	Pine St.-Rathdrum	Serious defect, repair immediately	Remediation Required	Crossarm - Broken	-	south arm busted open pretty good	wss3058	6/26/2019
12	27/3	Pine St.-Rathdrum	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
13	26/4	Pine St.-Rathdrum	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Split	-		wss3058	6/26/2019
14	26/2	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
15	25/3	Pine St.-Rathdrum	Moderate defect to be monitored	Remediation Required	Pole - Woodpecker Holes	-		wss3058	6/26/2019
17	24/3	Eighth & Fancher-Latah	Moderate defect to be monitored	Remediation Required	Pole - Split	-	roadside pole hollow top	wss3058	6/17/2019
18	27/10	Eighth & Fancher-Latah	Minor defect to be noted	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
19	28/2	Eighth & Fancher-Latah	Minor defect to be noted	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
20	14/12	Eighth & Fancher-Latah	Serious defect, repair inside 6 mo	Remediation Required	crossarm - HW loose	Pole - Split	guy need insulation	wss3058	6/17/2019
21	18/9	Eighth & Fancher-Latah	No defect	Remediation Required	Pole - Split	-		wss3058	5/24/2018
22	17/8	Eighth & Fancher-Latah	Serious defect, repair inside 6 mo	Needs Inspection	Pole - Split	-	rotten pole top	wss3058	6/17/2019
23	10/7	Eighth & Fancher-Latah	Moderate defect to be monitored	Remediation Required	Crossarm - Broken	-	split on north side	wss3058	6/17/2019
24	10/12	Eighth & Fancher-Latah	Minor defect to be noted	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
25	4/9	Eighth & Fancher-Latah	No defect	OK	Crossarm - Split	-		wss3058	6/17/2019
26	4/10	Eighth & Fancher-Latah	Moderate defect to be monitored	Needs Inspection	Crossarm - Split	-		wss3058	6/17/2019
27	5/5	Eighth & Fancher-Latah	Moderate defect to be monitored	Remediation Required	Crossarm - Split	-		wss3058	6/17/2019
28	8/10	Beacon-Boulder #1	Moderate defect to be monitored	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
30	10/7	Beacon-Boulder #2	No defect	Remediation Required	Pole - Split	-		wss3058	5/24/2018
31	5/7	Beacon-Boulder #1	Moderate defect to be monitored	OK	Phase Insulator - Broken	-	Repair next outage on the line	wz74pk	5/11/2017
32	3/5	Beacon-Boulder #1	Serious defect, repair inside 6 mo	Remediation Required	Crossarm - Broken	-		wss3058	6/17/2019
35	18/2	Lind-Warden	No defect	OK	Misc	-	REPLACE BEAR ONPOLE	wz74pk	6/13/2017
36	20/11	Lind-Warden	Moderate defect to be monitored	OK	Pole - Split	-		wz74pk	6/13/2017



	A	B	C	D	E	F	G
1	PM Work						
2	0	6	Replace		Confirmed, G Str 2 DG, 2 SG	3	str
3	0	8	Replace		Confirmed, H w 1 SG	3	str
4	9	5	PM Xarm	PM 2020	Replace arm	3	arm
5	11	3	Split Xarm	PM 2020	Replace arm, 11/4 restaple gnd	3	arm
6	11	6	Split Xarm	PM 2020	Dbl arm, wise to replace str	3	str
7	12	5	replace		confirmed	3	str
8	18	2	split Xarm	PM 2020	Confirmed, high priority	3	arm
9	19	4	stub + PM Xarm	PM 2020	H str	3	str
10	39	4	bad xarm	PM 2020	Y - high priority	3	arm
11	40	3	PM Xarm	PM 2020	confirmed, str	3	str
12	43	8	bad xarm	PM 2020	confirmed	3	arm
13	43	10	stub both		confirmed, bad shape str	3	str
14	53	10	stub both		confirmed, str this year	3	str
15	55	1	stub both, bad top		Confirmed, str, move 60' ahead to get out of creek?	3	str
16	56	5	replace, broken guy wire	guy, PM 20	confirmed - GDA, w side guy	3	str
17	62	11	addded		in bad shape	3	str
18	65	7	Low band, restub, and stub R	Xarm PM 2	yep, rough	3	str
19	65	10	replace		yep, rough	3	str
20	66	12	stub both, bad xarm, broken guy		hot mess, easy access though	3	str
21							
22	Reinforcement						
23	1	9	Stub/PWT - stub/replace	1		60 locations, 72 stubs	

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, attach as supporting documentation)]

Option	Capital Cost	Start	Complete
Mitigate Deficiencies	*$16.7M*	*01-2022*	*12-2026*
[Alternative #1]	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2]	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

The benefits of this Business Case are seen in something not happening. Pro-actively addressing near-term failures results in avoiding public safety risks including physical, electrical, and fire. A portion of this Business Case was previously funded through an Operations Business Case.

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 program is in the Execution Stage with spend directed primarily at structure and structure component change-outs resulting in facility failure avoidance.

[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.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects, internal construction resources typically perform the smaller jobs.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Replacing structures and structure components is presently the only alternative considered.

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.

Smaller projects can take place throughout the year. Most of the large projects take place in the Fall months and Transfer to Plant in the Novemeber time frame.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with Avista's Culture of Compliance. This Business Case directly impacts our customer, and places them as its focus.

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

Mitigation design solutions performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

None.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

3.2 Provide and discuss the governance processes and people that will provide oversight

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

Exh. HLR-2

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission Minor Rebuild Business Case Justification Narrative* 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: **APPROVED** *By Ken Sweigart at 7:38 am, Jan 04, 2022* Date:
Print Name:
Title:
Role: Business Case Owner

Signature: Date: 1/4/2022
Print Name: Josh DiLuciano
Title: Director of Electrical Engineering
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Transmission Construction - Compliance

EXECUTIVE SUMMARY

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"). It has 8 requirements and 57 sub-requirements related to planning and analysis, including the requirement for robust system models to determine system stability, voltage levels and system performance under various scenarios. This standard mandates that an annual planning assessment be conducted and corrective actions be identified and implemented to remedy any system performance deficiencies In addition, when Avista's system planning studies indicate any kind of problem that could arise in the transmission system, it must be remedied within specific timeframes. The Transmission Construction - Compliance Program provides funding to mitigate any identified reliability issues in order to remain in compliance with NERC requirements.

The implementation of this business case will be considered successful if these projects are all completed prior to the required compliance dates identified in the Engineering Roundtable Project List, which are copied from the Corrective Action Plans (within the annually published Avista System Planning Assessment).

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 anaysis either as a result of requests for facility additions, or identified past additions not analyzed at the time of installation.

The recommended solution is to build, rebuild, or reconductor transmission lines as identified in the Corrective Action Plans to stay in compliance with NERC mandatory and enforceable Reliability Standards (most notably TPL-001-4) and the NESC code (via WAC).

If Avista does not implement this business case, the company is at risk of violating NERC Reliability Standard Requirements and could be subject to penalties of up to $1M per day for the duration of any such violation. Following a "do nothing" option for this business case would likely be treated as an aggravating factor by the regulatory authority when assessing enforcement actions. If Avista does not fully implement this business case, it also runs the risk of being fined for not staying in compliance with the NESC code and WAC rules. There are no expected business impacts to continuing this program in place. A spend of $3,650,000 is needed to complete the planned 2022-2026 projects . This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

The Business Case contains four projects:

- *KEC Rimrock Substation Interconnection*
- *Beacon-Boulder #1 115kV Rebuild (east of Irvin)*
- *Ninth & Central-Sunset 115kV Partial Rebuild (Upgrade to 795 ACSS)*

The customer benefits from this Business Case through increased service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Daisy Drafter*	*Initial draft of original business case*	*4/15/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0				

Transmission Construction - Compliance

GENERAL INFORMATION

Requested Spend Amount	$3,650,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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. Corrective Action Plans must be completed within the required timeframe to meet the system performance requirements dictated by the Standard.

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 anaysis either as a result of requests for facility additions, or identified past additions not analyzed at the time of installation.

1.1 What is the current or potential problem that is being addressed? *NERC Reliability Standards and NESC loading capacities.*

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** *Mandatory & Compliance: Customer benefits by having a Transmission System in compliance with Federal Code and State Law.*

Identify why this work is needed now and what risks there are if not approved or is deferred

2.9 Concealment or Intentional Violation

NERC or the Regional Entity shall always consider as an aggravating factor any attempt by a violator to conceal the violation from NERC or the Regional Entity, or any intentional violation incurred for purposes other than a demonstrably good faith effort to avoid a significant and greater threat to the immediate reliability of the Bulk Power System.

2.10 Economic Choice to Violate

Penalties shall be sufficient to assure that entities responsible for complying with Reliability Standards do not have incentives to make economic choices that cause or unduly risk violations of Reliability Standards, or incidents resulting from violations of the Reliability Standards. Economic choice includes economic gain for, or the avoidance of costs to, the violator. NERC or the Regional Entity shall treat economic choice to violate as an aggravating factor when determining a Penalty.

2.15 Maximum Limitations on Penalties

In the United States, the maximum Penalty amount that NERC or a Regional Entity will assess for a violation of a Reliability Standard Requirement is $1,000,000 per day per violation. NERC and the Regional Entities will assess Penalties amounts up to and including this maximum amount for violations where warranted pursuant to these Sanction Guidelines.

In the case of projects addressing NESC capacity inadequacies, Avista will be cognisant of not meeting the WAC.

1.3 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

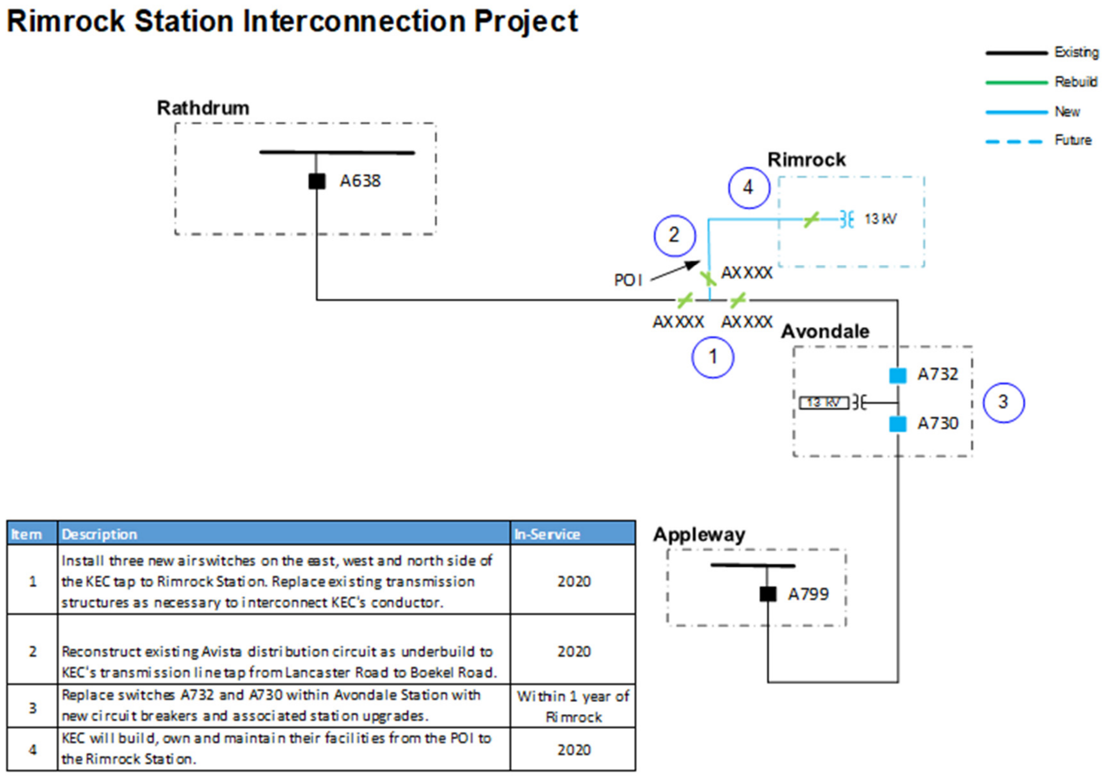
As-Built confirmation of mitigation measures.

1.4 Supplemental Information

1.4.1 Please reference and summarize any studies that support the problem

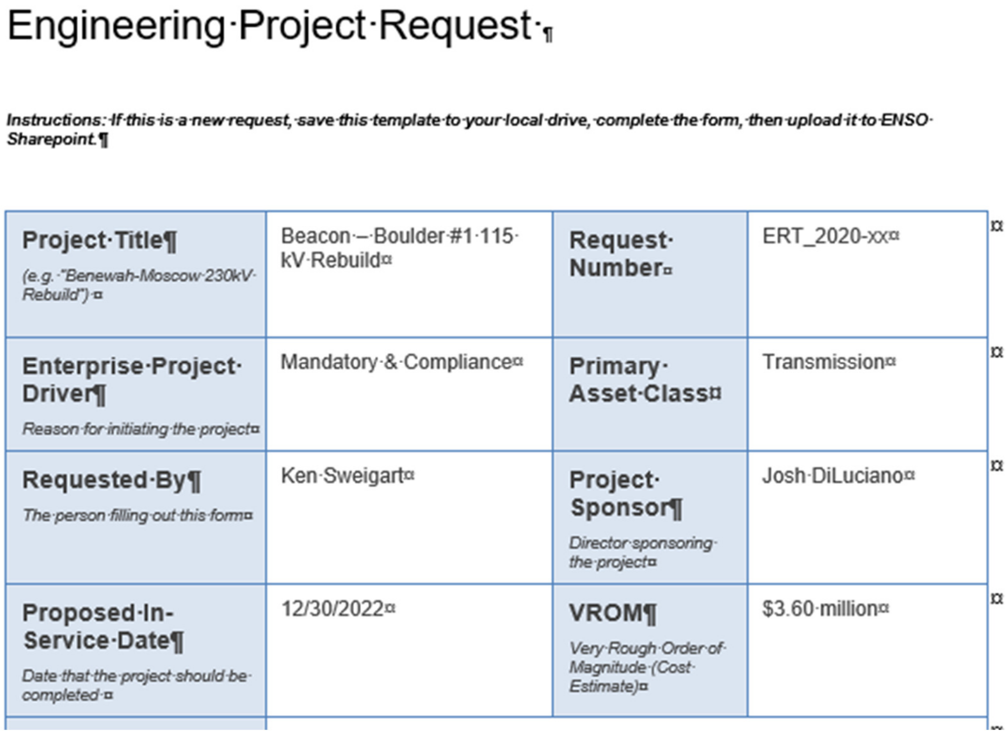
KEC Rimrock System Impact Study.docx
CAI Structure Analysis Results_BEA-BLD.xlsx
2019 Avista System Planning Assessment

1.4.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.



Item	Description	In-Service
1	Install three new air switches on the east, west and north side of the KEC tap to Rimrock Station. Replace existing transmission structures as necessary to interconnect KEC's conductor.	2020
2	Reconstruct existing Avista distribution circuit as underbuild to KEC's transmission line tap from Lancaster Road to Boekel Road.	2020
3	Replace switches A732 and A730 within Avondale Station with new circuit breakers and associated station upgrades.	Within 1 year of Rimrock
4	KEC will build, own and maintain their facilities from the POI to the Rimrock Station.	2020

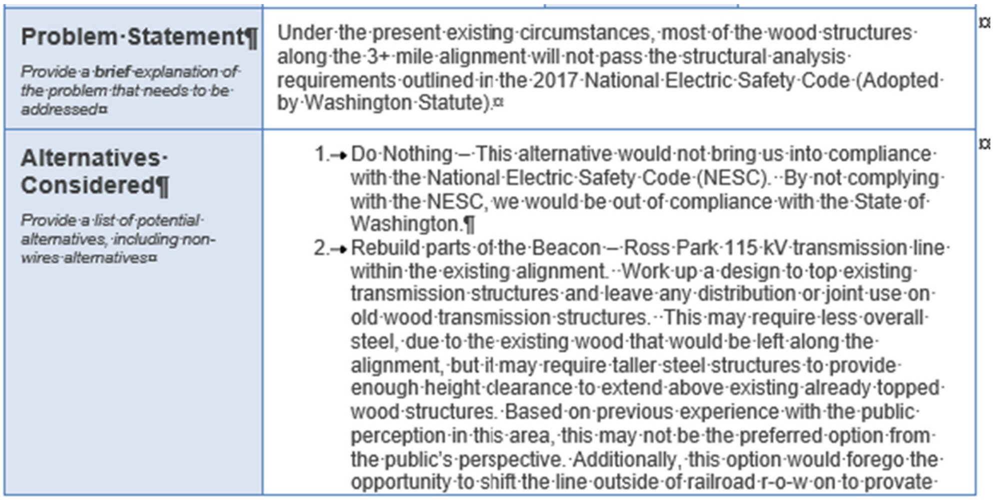
FIGURE·3:·RIMROCK·INTERCONNECTION·PROJECT·DIAGRAM¶



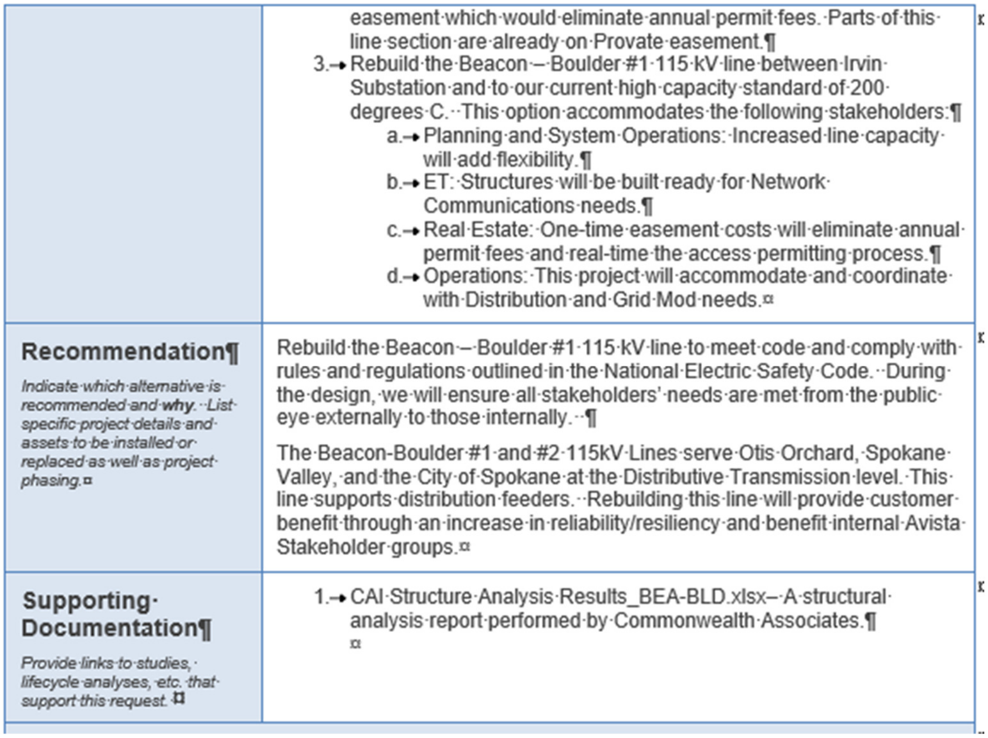
Engineering·Project·Request·¶

Instructions:·If·this·is·a·new·request,·save·this·template·to·your·local·drive,·complete·the·form,·then·upload·it·to·ENSO·Sharepoint.¶

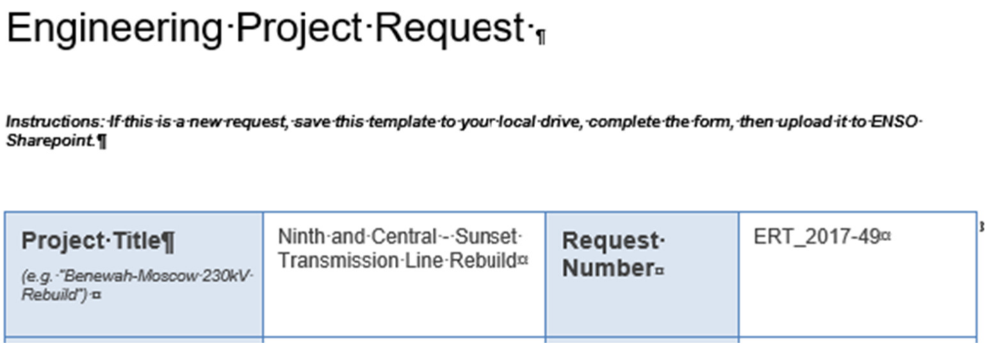
Project·Title¶ *(e.g.·"Benewah-Moscow·230kV·Rebuild")·¤*	Beacon·–·Boulder·#1·115·kV·Rebuild¤	**Request·Number¤**	ERT_2020-xx¤
Enterprise·Project·Driver¶ *Reason·for·initiating·the·project¤*	Mandatory·&·Compliance¤	**Primary·Asset·Class¤**	Transmission¤
Requested·By¶ *The·person·filling·out·this·form¤*	Ken·Sweigart¤	**Project·Sponsor¶** *Director·sponsoring·the·project¤*	Josh·DiLuciano¤
Proposed·In-Service·Date¶ *Date·that·the·project·should·be·completed·¤*	12/30/2022¤	**VROM¶** *Very·Rough·Order·of·Magnitude·(Cost·Estimate)¤*	$3.60·million¤



Problem Statement *Provide a **brief** explanation of the problem that needs to be addressed*	Under the present existing circumstances, most of the wood structures along the 3+ mile alignment will not pass the structural analysis requirements outlined in the 2017 National Electric Safety Code (Adopted by Washington Statute).
Alternatives Considered *Provide a list of potential alternatives, including non-wires alternatives*	1. Do Nothing – This alternative would not bring us into compliance with the National Electric Safety Code (NESC). By not complying with the NESC, we would be out of compliance with the State of Washington. 2. Rebuild parts of the Beacon – Ross Park 115 kV transmission line within the existing alignment. Work up a design to top existing transmission structures and leave any distribution or joint use on old wood transmission structures. This may require less overall steel, due to the existing wood that would be left along the alignment, but it may require taller steel structures to provide enough height clearance to extend above existing already topped wood structures. Based on previous experience with the public perception in this area, this may not be the preferred option from the public's perspective. Additionally, this option would forego the opportunity to shift the line outside of railroad r-o-w on to provate



	easement which would eliminate annual permit fees. Parts of this line section are already on Provate easement. 3. Rebuild the Beacon – Boulder #1 115 kV line between Irvin Substation and to our current high capacity standard of 200 degrees C. This option accommodates the following stakeholders: a. Planning and System Operations: Increased line capacity will add flexibility. b. ET: Structures will be built ready for Network Communications needs. c. Real Estate: One-time easement costs will eliminate annual permit fees and real-time the access permitting process. d. Operations: This project will accommodate and coordinate with Distribution and Grid Mod needs.
Recommendation *Indicate which alternative is recommended and **why**. List specific project details and assets to be installed or replaced as well as project phasing.*	Rebuild the Beacon – Boulder #1 115 kV line to meet code and comply with rules and regulations outlined in the National Electric Safety Code. During the design, we will ensure all stakeholders' needs are met from the public eye externally to those internally. The Beacon-Boulder #1 and #2 115kV Lines serve Otis Orchard, Spokane Valley, and the City of Spokane at the Distributive Transmission level. This line supports distribution feeders. Rebuilding this line will provide customer benefit through an increase in reliability/resiliency and benefit internal Avista Stakeholder groups.
Supporting Documentation *Provide links to studies, lifecycle analyses, etc. that support this request.*	1. CAI Structure Analysis Results_BEA-BLD.xlsx – A structural analysis report performed by Commonwealth Associates.

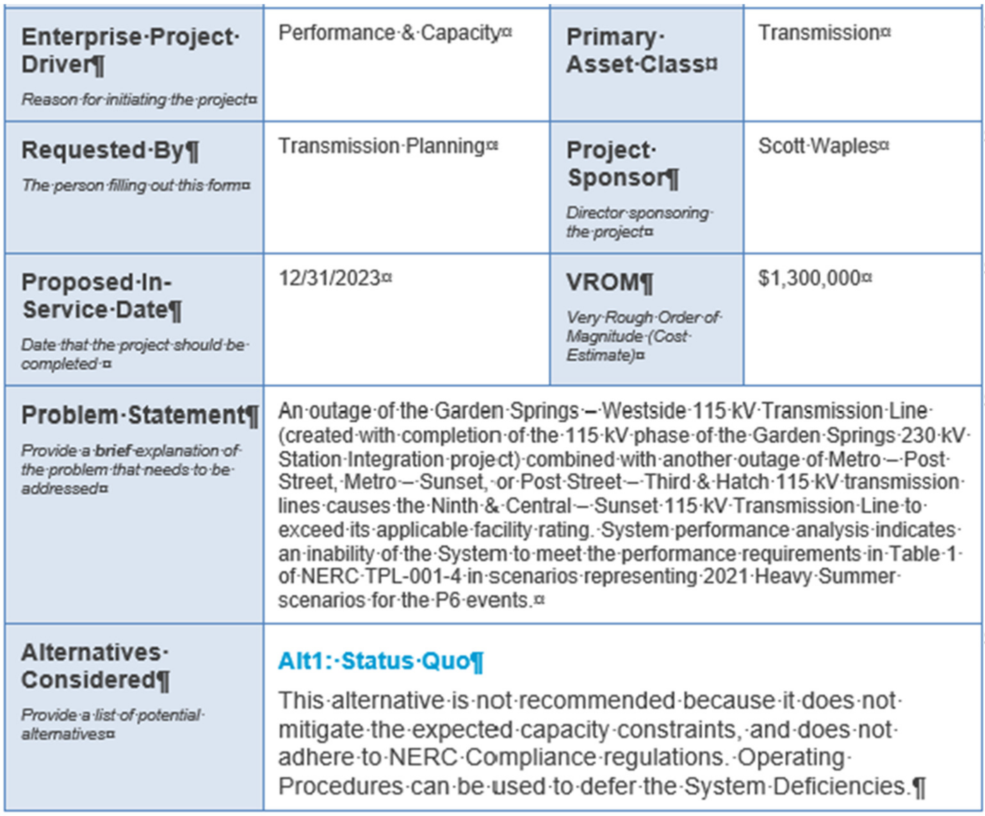


Engineering Project Request

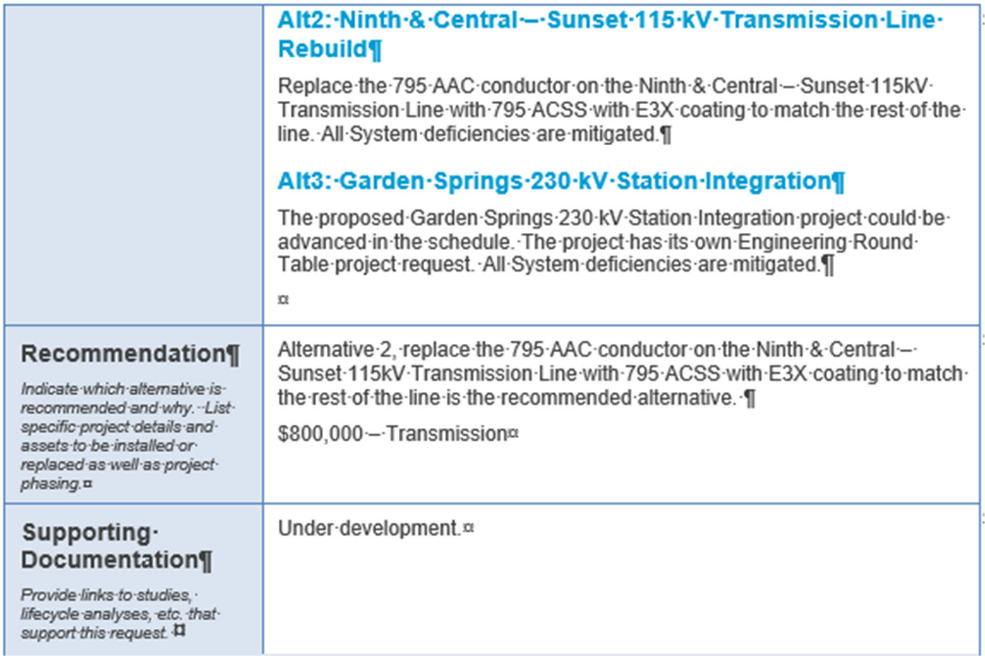
***Instructions:** If this is a new request, save this template to your local drive, complete the form, then upload it to ENSO Sharepoint.*

Project Title *(e.g. "Benewah-Moscow 230kV Rebuild")*	Ninth and Central - Sunset Transmission Line Rebuild	**Request Number**	ERT_2017-49

Transmission Construction - Compliance



Enterprise Project Driver *Reason for initiating the project*	Performance & Capacity	**Primary Asset Class**	Transmission
Requested By *The person filling out this form*	Transmission Planning	**Project Sponsor** *Director sponsoring the project*	Scott Waples
Proposed In-Service Date *Date that the project should be completed*	12/31/2023	**VROM** *Very Rough Order of Magnitude (Cost Estimate)*	$1,300,000
Problem Statement *Provide a **brief** explanation of the problem that needs to be addressed*	An outage of the Garden Springs – Westside 115 kV Transmission Line (created with completion of the 115 kV phase of the Garden Springs 230 kV Station Integration project) combined with another outage of Metro – Post Street, Metro – Sunset, or Post Street – Third & Hatch 115 kV transmission lines causes the Ninth & Central – Sunset 115 kV Transmission Line to exceed its applicable facility rating. System performance analysis indicates an inability of the System to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2021 Heavy Summer scenarios for the P6 events.		
Alternatives Considered *Provide a list of potential alternatives*	**Alt1: Status Quo** This alternative is not recommended because it does not mitigate the expected capacity constraints, and does not adhere to NERC Compliance regulations. Operating Procedures can be used to defer the System Deficiencies.		



	Alt2: Ninth & Central – Sunset 115 kV Transmission Line Rebuild Replace the 795 AAC conductor on the Ninth & Central – Sunset 115kV Transmission Line with 795 ACSS with E3X coating to match the rest of the line. All System deficiencies are mitigated. **Alt3: Garden Springs 230 kV Station Integration** The proposed Garden Springs 230 kV Station Integration project could be advanced in the schedule. The project has its own Engineering Round Table project request. All System deficiencies are mitigated.
Recommendation *Indicate which alternative is recommended and why. List specific project details and assets to be installed or replaced as well as project phasing.*	Alternative 2, replace the 795 AAC conductor on the Ninth & Central – Sunset 115kV Transmission Line with 795 ACSS with E3X coating to match the rest of the line is the recommended alternative. $800,000 – Transmission
Supporting Documentation *Provide links to studies, lifecycle analyses, etc. that support this request.*	Under development.

2. PROPOSAL AND RECOMMENDED SOLUTION

This is the continuation of a Program first started in 2012 (execution phase), and requires the mitigation of clearances violations.

Option	Capital Cost	Start	Complete
Maintain Compliance	*$3,65M*	*01-2022*	*12-2026*
[Alternative #1]	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2]	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

See 1.5.2

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 program is in the various stages based on individual project.

[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.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects, internal construction resources typically perform Spokane area jobs.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See 1.5.2.

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.

KEC Rimrock Substation Interconnection: 2020-2022
Beacon-Boulder #1 115kV Rebuild (east of Irvin): 2020-2022
Ninth & Central-Sunset 115kV Partial Rebuild (Upgrade to 795 ACSS): 2022-2023

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with Avista's Culture of Compliance.

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

Design solution performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

None.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

3.2 Provide and discuss the governance processes and people that will provide oversight

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission Construction – Compliance Business Case Justification Narrative* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

APPROVED
By Ken Sweigart at 7:39 am, Jan 04, 2022

Signature: Date:
Print Name:
Title:
Role: Business Case Owner

Signature: Date: 1/4/2022
Print Name: Josh DiLuciano
Title: Director of Electrical Engineering
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Transmission Major Rebuild – Asset Condition

EXECUTIVE SUMMARY

The Transmission Major Rebuild – Asset Condition Business Case covers major rebuilds of transmission lines due to overall asset condition. Factors such as operational issues, ease of access during outages, and potential for 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. This ranking is followed up by line specific studies. Projects are chosen to maximize stakeholder value.

Investments made under this program rebuild existing transmission lines based on overall asset condition. "Condition" is measured by useful life or the number of condition-related outages. Factors such as operational issues, ease of access during outages, and need to add automation or communications equipment may be included in the type of spending in this category. Replacing old and worn-out poles and cross-arms and other associated transmission equipment, help guard against increasing risk for more failures and outages. 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.

The implementation of this business case will be considered successful if these projects are completed as planned on time and on budget.

The recommended solution is to rebuild transmission lines as prioritized by the Engineering Roundtable group to ensure that Avista sufficiently addresses its aging Transmission Line infastructure. There are no expected business impacts to continuing this program in place. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North. A spend of $50,000,000 is needed to complete the projects as follows:

- *ER 2629, BI PT108 ($14,000,000): Hatwai-Moscow 230kV Transmission Line Rebuild*
- *ER 2596, BI LT900 ($36,000,000): Lolo-Oxbow 230kV Transmission Line Rebuild*

Avista customers benefit from this Business Case through improved service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Daisy Drafter*	*Initial draft of original business case*	*4/15/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0				

Transmission Major Rebuild – Asset Condition

GENERAL INFORMATION

Requested Spend Amount	$50,000,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

The Transmission Major Rebuild – Asset Condition Business Case covers nvestments made to rebuild existing transmission lines based on overall asset condition. "Condition" is measured by useful life or the number of condition-related outages. Factors such as operational issues, ease of access during outages, and need to add automation or communications equipment may be included in the type of spending in this category. Replacing old and worn-out poles and cross-arms and other associated transmission equipment, help guard against increasing risk for more failures and outages. 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.

1.1 What is the current or potential problem that is being addressed?

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.

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

Asset Condition: Customer benefits by having a reliable Transmission System capable of supporting service needs.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

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.

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 implementation of this business case will be considered successful if these projects are completed on time and within budget. Typical Project Management tracking tools in regards to schedule and budget will be employed, as well as construction inspection services.

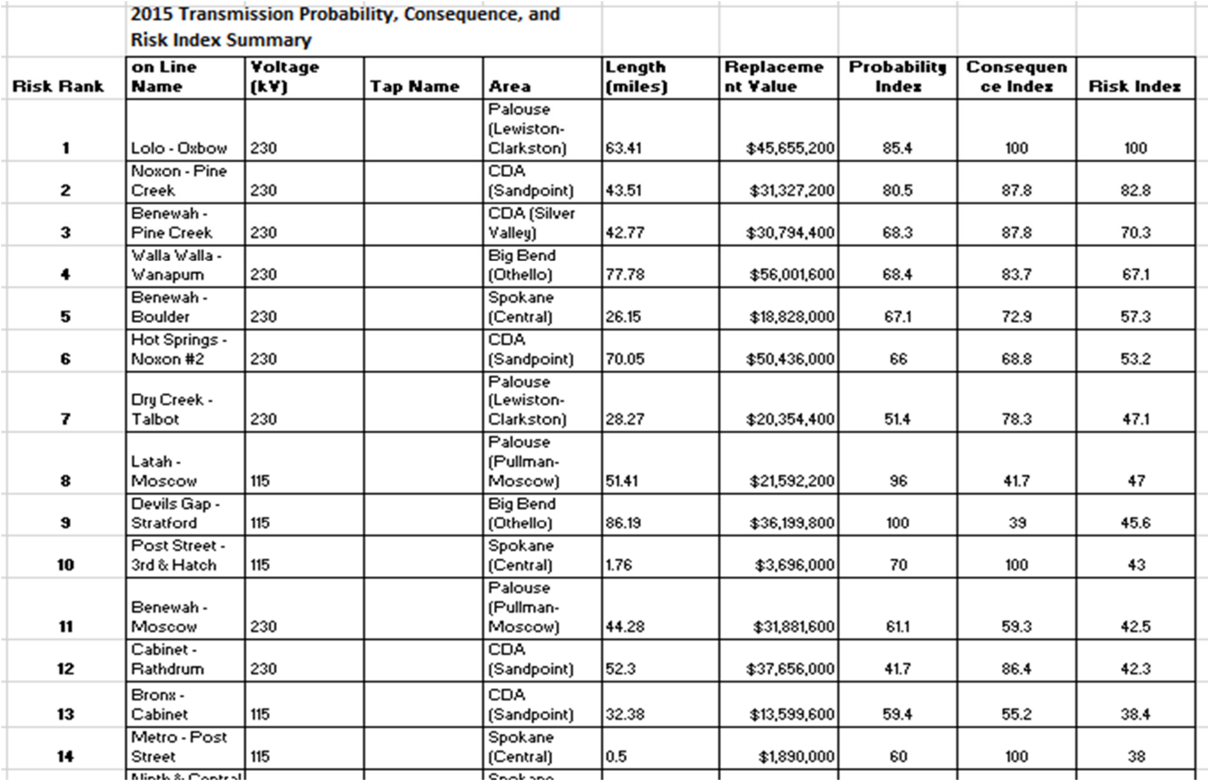
1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

2016 Lolo-Oxbow 230kV Model Asset Management Plan Rev a.docx
LOL-OXB – model results.pptx
HAT-MOS TT Data Breakdown.xlsx
Palouse (Pullman-Moscow) Transmission Reinforcement Program (2016 Summary).docx

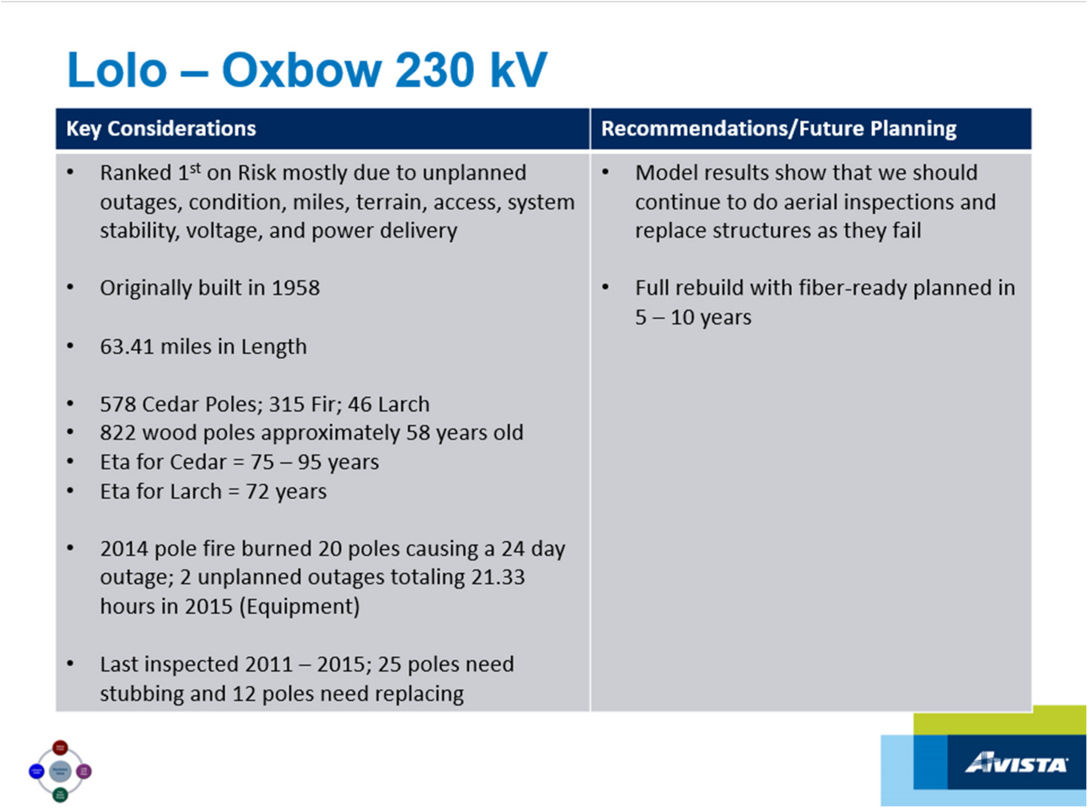
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Below are a few examples of the metric documents developed for this Business Case.



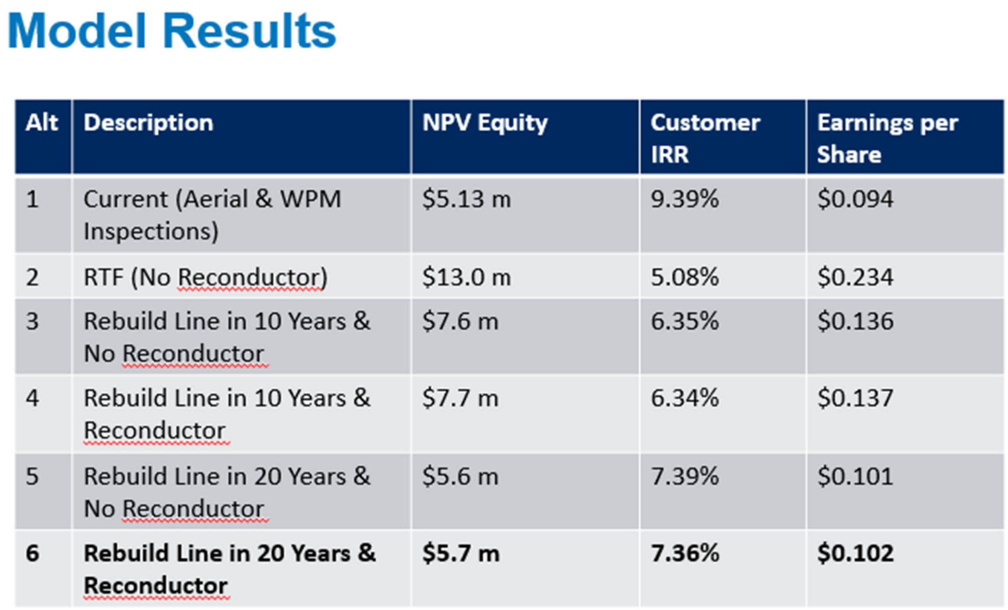
2015 Transmission Probability, Consequence, and Risk Index Summary

Risk Rank	on Line Name	Voltage (kV)	Tap Name	Area	Length (miles)	Replacement Value	Probability Index	Consequence Index	Risk Index
1	Lolo - Oxbow	230		Palouse (Lewiston-Clarkston)	63.41	$45,655,200	85.4	100	100
2	Noxon - Pine Creek	230		CDA (Sandpoint)	43.51	$31,327,200	80.5	87.8	82.8
3	Benewah - Pine Creek	230		CDA (Silver Valley)	42.77	$30,794,400	68.3	87.8	70.3
4	Walla Walla - Wanapum	230		Big Bend (Othello)	77.78	$56,001,600	68.4	83.7	67.1
5	Benewah - Boulder	230		Spokane (Central)	26.15	$18,828,000	67.1	72.9	57.3
6	Hot Springs - Noxon #2	230		CDA (Sandpoint)	70.05	$50,436,000	66	68.8	53.2
7	Dry Creek - Talbot	230		Palouse (Lewiston-Clarkston)	28.27	$20,354,400	51.4	78.3	47.1
8	Latah - Moscow	115		Palouse (Pullman-Moscow)	51.41	$21,592,200	96	41.7	47
9	Devils Gap - Stratford	115		Big Bend (Othello)	86.19	$36,199,800	100	39	45.6
10	Post Street - 3rd & Hatch	115		Spokane (Central)	1.76	$3,696,000	70	100	43
11	Benewah - Moscow	230		Palouse (Pullman-Moscow)	44.28	$31,881,600	61.1	59.3	42.5
12	Cabinet - Rathdrum	230		CDA (Sandpoint)	52.3	$37,656,000	41.7	86.4	42.3
13	Bronx - Cabinet	115		CDA (Sandpoint)	32.38	$13,599,600	59.4	55.2	38.4
14	Metro - Post Street	115		Spokane (Central)	0.5	$1,890,000	60	100	38



Lolo – Oxbow 230 kV

Key Considerations	Recommendations/Future Planning
• Ranked 1st on Risk mostly due to unplanned outages, condition, miles, terrain, access, system stability, voltage, and power delivery • Originally built in 1958 • 63.41 miles in Length • 578 Cedar Poles; 315 Fir; 46 Larch • 822 wood poles approximately 58 years old • Eta for Cedar = 75 – 95 years • Eta for Larch = 72 years • 2014 pole fire burned 20 poles causing a 24 day outage; 2 unplanned outages totaling 21.33 hours in 2015 (Equipment) • Last inspected 2011 – 2015; 25 poles need stubbing and 12 poles need replacing	• Model results show that we should continue to do aerial inspections and replace structures as they fail • Full rebuild with fiber-ready planned in 5 – 10 years



Model Results

Alt	Description	NPV Equity	Customer IRR	Earnings per Share
1	Current (Aerial & WPM Inspections)	$5.13 m	9.39%	$0.094
2	RTF (No Reconductor)	$13.0 m	5.08%	$0.234
3	Rebuild Line in 10 Years & No Reconductor	$7.6 m	6.35%	$0.136
4	Rebuild Line in 10 Years & Reconductor	$7.7 m	6.34%	$0.137
5	Rebuild Line in 20 Years & No Reconductor	$5.6 m	7.39%	$0.101
6	**Rebuild Line in 20 Years & Reconductor**	**$5.7 m**	**7.36%**	**$0.102**

The Lolo-Oxbow 230kV Line is #1 on the Asset Condition Risk Index. Given the history of outages due to fire, the time and effort required to mobilize and rebuild in this very remote location, lost revenue during outages, and the desire by Transmission Planning to upgrade this line to match the Idaho Power Company portion of the line, it is recommended to pursue the Rebuild and Reconductor Option.

The Hatwai-Moscow 230kV Line is further down on the Asset Condition Risk Index, but recent Test & Treat data shows that 20%-25% of the line structures need to be replaced in the very short term. This line is the same vintage as the Benewah-Moscow 230kV that was rebuild due to Asset Condition in 2018..

2. PROPOSAL AND RECOMMENDED SOLUTION

This is the continuation of an ongoing Program, and requires the replacement of aging infastructure to support service levels. Please see Alternatives Evaluation within documents referenced in *Section 1.6.*1, and information shown in Section 1.6.2 *for details.*

Option	Capital Cost	Start	Complete
Rebuild Infastructure	*$50M*	*01-2022*	*12-2026*
[Alternative #1]	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2]	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

The benefits of this Business Case are seen in being able to support overall Asset Management strategies.

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.

- *ER 2629, BI PT108 ($14,000,000): The Hatwai-Moscow 230kV Transmission Line Rebuild Project is scheduled to design and construct between 2022-2023.*
- *ER 2596, BI LT900 ($36,000,000): The Lolo-Oxbow 230kV Transmission Line Rebuild Project began construction in 2020, and will complete in 2025. Used and Useful and Transferred to Plant in Fall/Winter of each year between 2022 and 2026.*

[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.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects. Design resources can be supplemented by local consulting services.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Please see documents referenced in Section 1.6.1, and information shown in Section 1.6.2.

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.

Please see Section 2.2.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with the Focus Areas of Customers and Perform.

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

Design solutions performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

None.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

3.2 Provide and discuss the governance processes and people that will provide oversight

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission Major Rebuild – Asset Condition Business Case Justification Narrative* 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: **APPROVED** By Ken Sweigart at 7:40 am, Jan 04, 2022 Date:
Print Name:
Title:
Role: Business Case Owner

Signature: Date: 1/4/2022
Print Name: Josh DiLuciano
Title: Director of Electrical Engineering
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Transmission NERC Low Priority Ratings Mitigation

EXECUTIVE SUMMARY

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 2023.

The recommended solution is to correct the issues found in the LiDAR studies to stay in compliance with the NESC code and WAC. There are no expected business impacts to continuing this program in place. If Avista does not fully implement this business case, it runs the risk of being fined for not staying in compliance with the NESC code and WAC rules. A spend of $5,000,000 is needed to complete the mitigations by 2023. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North.

The customer benefits from this Business Case through increased service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Daisy Drafter*	*Initial draft of original business case*	*4/15/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0				

Transmission NERC Low Priority Ratings Mitigation

GENERAL INFORMATION

Requested Spend Amount	$5,000,000
Requested Spend Time Period	*2 years*
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

The Transmission NERC Medium 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).

1.1 What is the current or potential problem that is being addressed? *Clearance violations.*

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** *Mandatory & Compliance: Customer benefits by having a Transmission System in compliance with Federal Code and State Law.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred *The North American Electric Reliability Corporations (NERC) "NERC Alert" originally identified Low Priority Transmission Line assessments to complete by December 31, 2013. Although a mitigation timeline did not include a penalty threat, we have been operating under a grace period that requires us to report progress every six months. Completing the program by 2023 will show us taking ten years to complete the effort. Deferring completion is tempting greater scrutiny from NERC and delays mitigation of a compliance violations recognized by Washington State Law.*

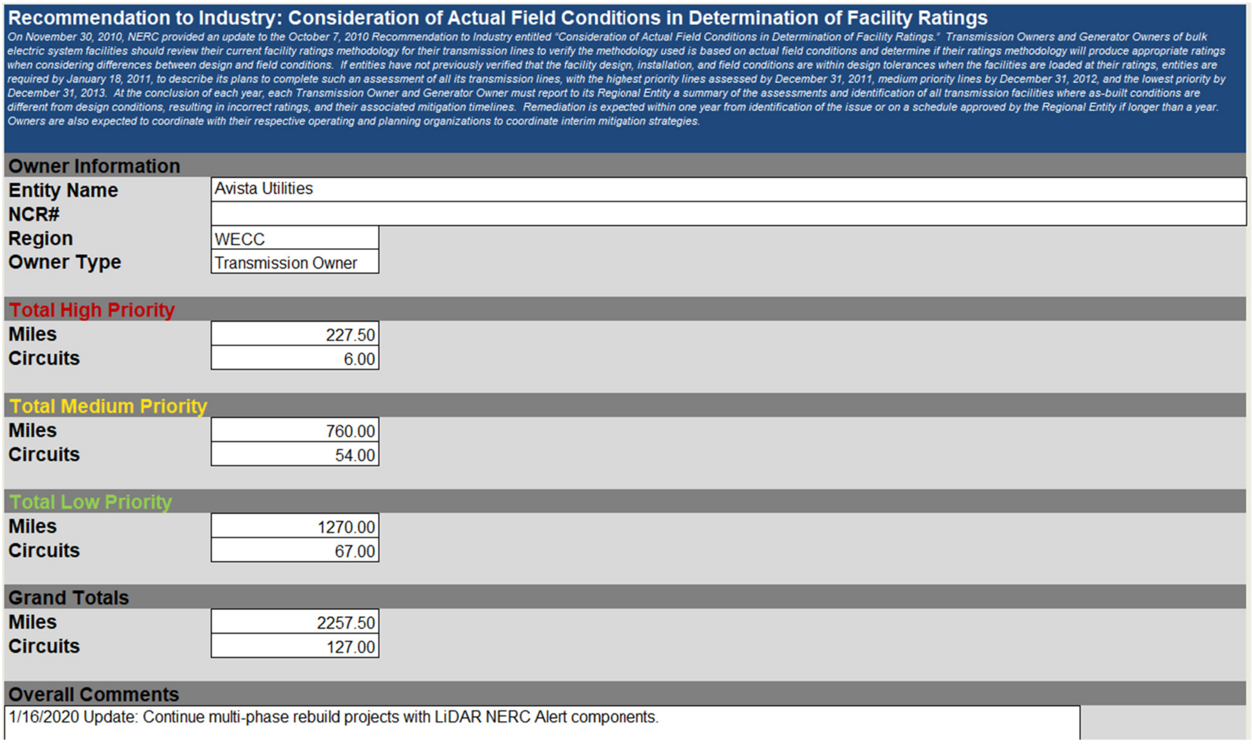
1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above. *As-Built confirmation of mitigation measures.*

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

CAN-0009_FAC-008 FAC-009.pdf

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.



Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings

On November 30, 2010, NERC provided an update to the October 7, 2010 Recommendation to Industry entitled "Consideration of Actual Field Conditions in Determination of Facility Ratings." Transmission Owners and Generator Owners of bulk electric system facilities should review their current facility ratings methodology for their transmission lines to verify the methodology used is based on actual field conditions and determine if their ratings methodology will produce appropriate ratings when considering differences between design and field conditions. If entities have not previously verified that the facility design, installation, and field conditions are within design tolerances when the facilities are loaded at their ratings, entities are required by January 18, 2011, to describe its plans to complete such an assessment of all its transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority by December 31, 2013. At the conclusion of each year, each Transmission Owner and Generator Owner must report to its Regional Entity a summary of the assessments and identification of all transmission facilities where as-built conditions are different from design conditions, resulting in incorrect ratings, and their associated mitigation timelines. Remediation is expected within one year from identification of the issue or on a schedule approved by the Regional Entity if longer than a year. Owners are also expected to coordinate with their respective operating and planning organizations to coordinate interim mitigation strategies.

Owner Information

Entity Name	Avista Utilities
NCR#	
Region	WECC
Owner Type	Transmission Owner

Total High Priority

Miles	227.50
Circuits	6.00

Total Medium Priority

Miles	760.00
Circuits	54.00

Total Low Priority

Miles	1270.00
Circuits	67.00

Grand Totals

Miles	2257.50
Circuits	127.00

Overall Comments

1/16/2020 Update: Continue multi-phase rebuild projects with LiDAR NERC Alert components.

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, attach as supporting documentation)]

Option	Capital Cost	Start	Complete
Mitigate Violations	*$5.0M*	*01-2022*	*12-2023*
[Alternative #1]	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2]	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

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.

This program is in the Execution Stage with spend directed primarily at structure change-outs resulting in greater ground clearance.

[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.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects, internal construction resources typically perform the smaller jobs.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Raising structure heights is by far the go to alternative. In one instance the removal of earth was used. Earth removal can trigger permitting, which otherwise would not be necessary.

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.

Smaller projects can take place throughout the year. Most of the large projects take place in the Fall months and Transfer to Plant in the November time frame.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with Avista's Culture of Compliance.

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

Mitigation design solution performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

None

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Engineering Roundtable functions as the Vetting Platform, Steering Committee, and Advisory Group.

3.2 Provide and discuss the governance processes and people that will provide oversight

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Low Priority Rating Mitigation Business Case Justification Narrative* 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: **APPROVED**
By Ken Sweigart at 7:36 am, Jan 04, 2022
Date:
Print Name:
Title:
Role: Business Case Owner

Signature:
Date: 1/4/2022
Print Name: Josh DiLuciano
Title: Director of Electrical Engineering
Role: Business Case Sponsor

Signature:
Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Westside 230/115kV Station Rebuild

EXECUTIVE SUMMARY

*This section is reserved to provide a **brief** description of the business case and high level summary of the projects or programs included. Please limit to no more than 2 paragraphs. Components that should be included: 1) a synopsis of the problem, 2) the service code and jurisdiction of customers impacted, 3) the recommended solution, 4) the cost of the solution, 5) how the solution will benefit customers identified, 6) the significance of the timeline and 7) the risks of not approving this business case.*
<< Both the Executive Summary and Version History should fit into one page >>

The existing Westside #1 230/115 kV transformer exceeds its applicable facility rating for the P1 event of the Westside #2 230/115 kV transformer. System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events. While Avista intends to avoid proactively shedding customer load, an operating procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4).

Westside Transformer Replacement is the recommended solution. Replace the existing Westside transformers with 250 MVA rated transformers and reconstruct both the 230 kV and 115 kV buses at the station to double bus, double breaker. All associated system deficiencies will be mitigated.

Service: ED – Electric Direct

Jurisdiction: AN – Allocated North

Engineering Roundtable Request Number: ERT_2017-47

Cost of Solution: $32,000,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Ken Sweigart	Initial Version	4/14/2017	Initial Version
2.0	Karen Kusel / Glenn Madden	Update to 2020 Template	6/2020	

Westside 230/115kV Station Rebuild

GENERAL INFORMATION

Requested Spend Amount	$32,000,000
Requested Spend Time Period	15 Years
Requesting Organization/Department	Transmission/System Planning
Business Case Owner | Sponsor	Glenn Madden | Josh DiLuciano
Sponsor Organization/Department	T&D
Phase	Execution
Category	Project
Driver	Mandatory & Compliance

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]

The existing Westside #1 230/115 kV transformer exceeds its applicable facility rating for the P1 event of the Westside #2 230/115 kV transformer. System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events. While Avista intends to avoid proactively shedding customer load, an operating procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4).

1.1 What is the current or potential problem that is being addressed?

System performance analysis indicates an inability of the system to meet the performance requirements in Table 1 of NERC TPL-001-4 in scenarios representing 2017 Heavy Summer for P1 events.

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

Mandatory & Complaince - All associated system deficiencies will be mitigated with the completion of this project.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

While Avista intends to avoid proactively shedding customer load, an operating procedure to shed non-consequential load can be used until 2021 to mitigate system deficiencies (non-consequential load shedding is considered acceptable through the 84 month implementation of TPL-001-4).

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.

Future System Planning Assessments which show mitigation of all prior deficiencies.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

System Planning Assessments.

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.

Not Applicable.

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, attach as supporting documentation)]

Westside Transformer Replacement is the recommended solution. Replace the existing Westside transformers with 250 MVA rated transformers and reconstruct both the 230 kV and 115 kV buses at the station to double bus, double breaker. All associated system deficiencies will be mitigated.

Project scope includes the following:

Phase 1: Replace the existing Westside #1 230/115 kV transformer and construct necessary bus work and breaker positions. $11 million, energize 2018

Phase 2: Continue bus work and breaker replacement: $8 million, energize 2019

Phase 3: Replace the existing Westside #2 230/115 kV transformer and complete bus work to single bus configuration: $6 million, energize 2020

Phase 4: Complete bus work to double bus, double breaker on both the 230 kV and 115 kV buses: $7 million, energize 2022

Alternative 1 - Status Quo/Do Nothing: This alternative is not recommended because it does not mitigate the expected capacity constraints and does not adhere to NERC transmission planning standards.

Solution/Alternative 2 - Westside Transformer Replacement: Replace the existing Westside transformers with 250 MVA rated transformers and reconstruct both the 230 kV and 115 kV buses at the station to double bus, double breaker. All associated system deficiencies will be mitigated.

Alternative 3- Garden Springs 230kV Station Integration: The Garden Springs 230 kV Station Integration project includes the installation of new 230/115 kV transformation in the Spokane area. The additional transformation will offload the Westside #1 and #2 230/115 transformers. In the future, the Garden Springs 230 kV Station Integration project will be necessary in addition to the Westside Transformer Replacement project.

Alternative 4 - Replace Westside Transformers without Station Rebuild: Replacing the existing Westside transformers to 250 MVA rated transformers will mitigate the transformer overload system deficiencies but will create a short circuit breaker rating exceedance. Additional P2 bus outage system deficiencies will exist.

Westside 230/115kV Station Rebuild

Option	**Capital Cost**	**Start**	**Complete**
[Recommended Solution] Westside Transformer Replacement	$32M	2015	2022
Alternative #1 Status Quo	$0M		
Alternative #3 Garden Springs 230kV Station Integration			
Alternative #4 Replace Westside Transformers without Station Rebuild			

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:
- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

System Planning Assessments.

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.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[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.]

2020 – $3,000,000

2021 - $3,500,000

2022 - $2,800,000

2023 - $2,000,000

2024 – $1,000,000

O&M costs will be comparible to what they were before this project.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

System Operations will have improved functionality of the electric system.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See Section 2.0 for alternative discussion.

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. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

Construction will continue through 2024. Transfers to Plant will be at the close of each Phase.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.]

Mission: We improve our customers' lives through innovative energy solutions.

Vision: Better energy for life

The completion of this project leads directly to a dimished threat of customer outages.

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

The scope for the project, which is to increase transformation capacity in the Spokane area is the least cost option that provides the needed functionality. Adhering to the scope and project objectives will be reviewed regularly by the project team including the project engineer and the project manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electrical Engineering, Generation Production/Substation Support, Transmission Operations and System Planning and Operations

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

Not Applicable.

3 MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

- Project Engineer/Project Manager (PE/PM)- Dana Gerbing/Zachary Curry
- Engineering Roundtable Committee

The assigned PE/PM holds stakeholder meetings to develop/confirm scope, schedule and costs. Also meets at time of pre-construction. Other meetings held as necessary.

This project has also been reviewed by the Engineering Roundtable.

3.2 Provide and discuss the governance processes and people that will provide oversight

Engineering Roundtable meets several times a year to analyze current and future projects.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project folders are saved to Engineering shared drives and Businesss Case Funds Requests are available on the Finance sharepoint site

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Westside 230/115kV Station Rebuild 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: Glenn J Madden Date: 1-3-2022
Print Name: Glenn Madden
Title: Manager, Substation Engineering
Role: Business Case Owner

Signature: Date: 1/4/2022
Print Name: Josh DiLuciano
Title: Director, Electrical Engineering
Role: Business Case Sponsor

Signature: Damon Fisher Date: 1/4/2022
Print Name: Damon Fisher
Title: Principle Engineer
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Wood Pole Management

EXECUTIVE SUMMARY

Asset Management and Distribution Engineering provide ongoing analysis of distribution assets and their condition. This analysis is used to direct the Wood Pole Management (WPM) work that includes inspecting and maintaining Avista's poles, hardware, and equipment on a twenty-year cycle. The operating guidelines are documented in the Structure Specific Distribution Feeder Management Plan. Asset Maintenance collaborates with Electric Operations and contractors to coordinate and complete the work. Asset Maintenance manages and tracks the work, budget, scope, and schedule. Starting in 2020, WPM is integrating the Wildfire Urban Interface (WUI) program scope into its work plan. The goal is to complete the WUI work by 2030. The major drivers for the program are system reliability, improved cost performance, reduced customer outages, and reduction in fire risk. These drivers are achieved by replacing defective poles, associated hardware, and equipment at the end of its useful life or if the condition of the asset requires replacement. The National Electrical Safety Code (NESC) is adopted as Washington Law under WAC 296-45-045. Part 013C of this code describes the application, Part 121 defines the inspection interval, and Part 214A details documentation and correction of the pole inspection results.

WPM work encompasses Avista's electric distribution overhead facilities in Washington, Idaho, and Montana. In order to maintain a twenty-year cycle, approximately 11,400 poles need to be inspected annually. The work plan is developed to complete 66% of the poles in the state of Washington and 34% of the poles in Idaho each year. For the past three years, the spend has been approximately $10.5M; however, the anticipated spending level needs to be increased to the $17M range due to inclusion of the WUI program into the WPM work plan. This increase accelerates the twenty-year WPM inspection cycle in order to meet the required ten-year WUI cycle. In addition, with current costs, the historical $10.5M funding level does not support completing the identified component replacements on a twenty-year cycle. In 2019, the average cost to mitigate defective items identified during the inspection process was $1,093.49 per pole. As utilities become more susceptible to wildfire litigation it is imperative that the system is inspected, and the defective assets mitigated in a timely fashion. Keeping WPM on a $10.5M annual budget will push work further into the future which increases safety and fire risks to the community and the reliability to our customers.

Version	Author	Description	Date	Notes
1.0	*Mark Gabert*	*Initial draft of original business case*	*7/1/2020*	
2.0	*Mark Gabert*	*Final draft of the original business case*	*7/31/2020*	

Wood Pole Management

GENERAL INFORMATION

Requested Spend Amount	$88,871,382
Requested Spend Time Period	*5 years*
Requesting Organization/Department	Asset Maintenance/WPM
Business Case Owner | Sponsor	Mark S. Gabert | Alicia Gibbs | David Howell
Sponsor Organization/Department	M51/WPM
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

The current Wood Pole Management (WPM) program inspects and maintains the existing distribution wood poles on a twenty-year cycle and the transmission poles on a fifteen-year cycle. Avista has 7,702 overhead distribution circuit miles. According to the 2017 Wood Pole Management Review and Recommendations the average age of a wood pole is twenty-eight years with a standard deviation of twenty-one years. Nearly 20% of all poles are over fifty years old and there are an estimated 230,000 distribution poles in the system. This means approximately 46,000 poles are currently over fifty years old. Our current inspection cycle allows us to reach approximately 11,400 poles each year. Starting in 2021, 14,854 poles need to be inspected each year because the Wildfire Urban Interface (WUI) program is being integrated into the inspections. This increase in inspections will ensure the poles are inspected and maintained on a twenty-year cycle. Along with inspecting the poles, WPM inspects distribution transformers, cutouts, insulators, wildlife guards, lightning arresters, crossarms, pole guying, and pole grounds. The average asset life of this equipment is fifty-five years and requires replacement along with the pole work. The inspections document the asset condition and indicate what work is required to be replaced, and assets that are damaged or near their failure point. The asset condition is observed and documented during the pole inspection process as indicated in both the S-622 Specification for the Inspection of Poles, and the Structure Specific Distribution Feeder Management Plan (DFMP) located on the Asset Maintenance Sharepoint Site Designs and work plans are then created to replace the aging infrastructure. The construction work to replace the assets is also part of this program.

1.1 What is the current or potential problem that is being addressed?

This program addresses issues such as outages, safety risks, fire risks, and unplanned maintenance. This is accomplished by inspecting, documenting, and maintaining our overhead facilities in a useful condition on a twenty-year cycle. This keeps our poles safe for employees and the general public while maintaining a high level of customer satisfaction. As of 2020, WPM is tracking on a twenty-year cycle, however, as the Grid Modernization Program (GMP) budget is reduced, there is an impact on the recommended twenty-year cycle. GMP contributes to WPM's ability to maintain the required poles needed to remain on the twenty-year cycle. The WUI Program is another impact to maintaining the twenty-year cycle. With the addition of the WUI program, WPM will need to re-inspect some poles in the system sooner than the twenty-year cycle so the required WUI work can be completed. If unfunded to expedite the plan, poles will be pushed past the twenty-year cycle in order to meet the demand from the WUI program and with the reduction of GMP budget.

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

From an Asset Condition perspective, the major drivers for the program include safety, system reliability, improved cost performance, reduced customer outages, and decreased fire risk. These drivers are addressed by replacing defective poles, associated hardware, and equipment at its end of life or as required by asset condition. This program also has a mandatory and compliance component to it because the National Electrical Safety Code (NESC) is adopted as Washington Law under WAC 296-45-045. Part 013C of this code describes the application, Part 121 defines the inspection interval, and Part 214A details documentation and correction of the pole inspection results.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

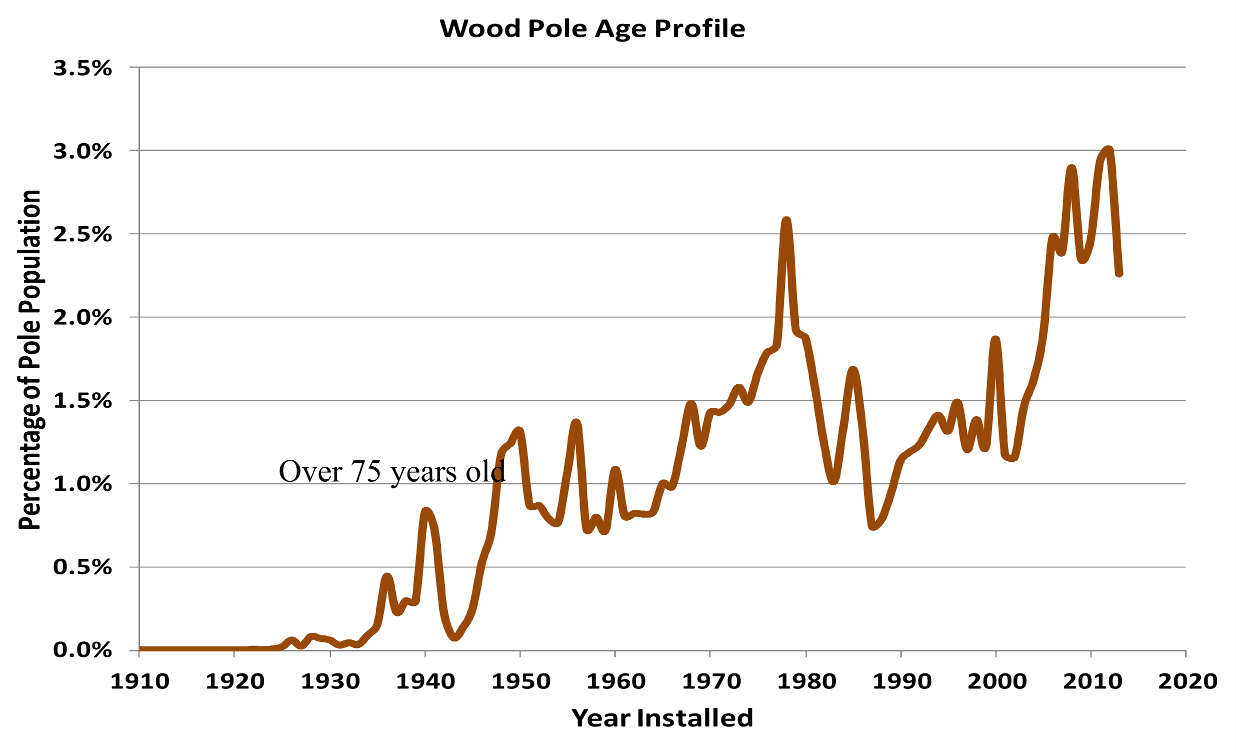
The work is required now to keep pace with the aging assets and expected failure rate. Figure 1 below shows the increased rate at which the poles are reaching the seventy-five year-end of life. If this work is not maintained, this aging infrastructure will cause an increasing number of failures leading to increased outages and higher construction costs as it is much more expensive to respond to an asset failure than to have it replaced in a planned program.

In addition to the risks of fires, outages, and failures with the aging equipment, the additional risks associated with this program pertain to the following:

> **Environmental:** Risks include potential large volume transformer oil spill, difficult hazardous waste cleanup, impact to waterways, and repeated or moderate air emission exceedance. According to the 2017 Wood Pole Management Review and Recommendations if the program is unfunded the potential occurrence is greater than four spills per year. If funded, the potential occurrence is less than one per fifty years.
>
> **Public Safety and Health**: Risks include a potential for serious injury for crews or the public, significant damage to equipment, property or businesses, public health infrastructure impact up to forty-eight hours. If the program is unfunded, the potential occurrence is less than one per ten years. If funded the potential occurrence is less than one per fifty years.

Wood Pole Management

Figure 1- Pole Age Profile



The Outage Management Tool (OMT) is used by Asset Management to track asset conditions and show trends of failures of specific equipment that should be targeted for replacement. This information is also used to track key program performance as shown in Table 1 below. The number of outage type events has been reduced by over 36% from 2009 through 2017. This reduction in outage events results in significant customer benefit. This reduction also demonstrates increased reliability and safety along with a reduction in outages. The original goal for this KPI was to stay below the number of events averaged over 2005-2009 for WPM Related OMT Events. The goal will be re-evaluated by Asset Management in the future.

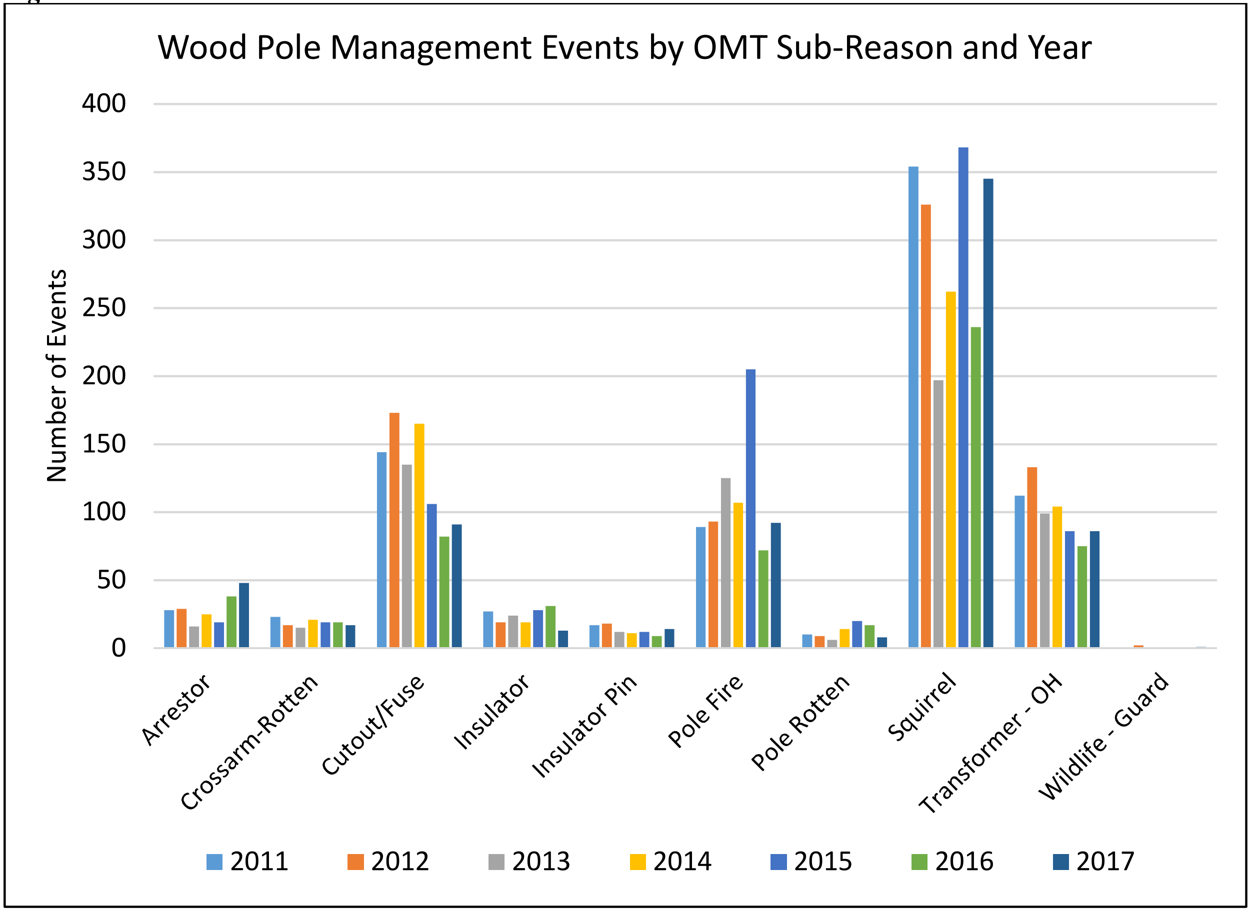
Table 1: Event Reduction Results

	WPM Goal Related Number of OMT Events	Actual WPM Related Number of OMT Events	Projected Miles Follow-Up Work	Actual Miles Follow-Up Work
2009	1460	1320	500	372
2010	1460	1004	450	435
2011	1460	1004	459	333
2012	1460	1013	416	435
2013	1460	816	445	329
2014	1460	905	412	385
2015	1460	760	390	364
2016	1460	717	389	423
2017	1460	888	389	492

Wood Pole Management

The type of OMT events are broken down into more detail in Figure 2. Note there are significant improvements to some events such as annual squirrel events being reduced from nearly 750 to around 240 events. This improvement has been realized by adding wildlife guards to the top of transformer bushings in order to prevent squirrels from touching exposed power connections which can result in outages. Both the transformer and cutout\fuse events have been reduced by over 50% through the replacement of aged equipment. Figure 2 also reveals a concerning upward trend of pole-rotten events that indicate the impact of the aging poles. Note that the calculated cost to customers for a pole failure is $24,400 based on an average duration of 4.8 hours for 80 customers[1]. Other key OMT events that have been significantly reduced from 2009 to 2016 include Transformer, Cutout/Fuse, and Squirrel. The combined cost impact to customers in 2015 alone for those events was $2,265,600. See Figure 2.

Figure 2: OMT Events



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[1] Source: 2017 Wood Pole Management Review and Recommendation)

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.

Ultimately the impact of this Program can be associated with our Electric Systems Reliability metrics. The System Average Interruption Frequency Index (SAIFI) represents the average number of sustained interruptions per customer for the year across Avista's entire system. Avista reported a SAIFI score of 1.05 for the year 2015. The Asset Management group created Table 2 below to show the impact of this Program to our overall SAIFI score. The predicted contribution is about 0.211, which has a significant impact on the customer, whereas without WPM the contribution to SAIFI would be 0.57. This means the customer would experience 0.36 more outages per year without WPM. Without WPM, the contribution to SAIDI would be 1.27 (hours).

Table 2: SAIFI Metrics

Projected Metric Description	Projected WPM Contribution To The Annual SAIFI Number	Projected Number of Dist Poles Inspected	Model Predicted Material Use for WPM Follow-up Work	Projected Number of Pole Rotten OMT Events	Projected Number of Crossarm OMT Events
2009	0.214024996	12,600	4,792	137	32
2010	0.208489356	12,600	4,932	137	32
2011	0.211022023	12,600	5,010	137	32
2012	0.211022023	12,600	6,770	137	32
2013	0.211022023	12,600	8,592	137	32
2014	0.211022023	12,600	10,566	137	32
2015	0.211022023	12,600	12,606	137	32
Actual Metric Description	**Actual WPM Contribution To The Annual SAIFI Number**	**Actual Number of Dist Poles Inspected**	**Actual Material Use for WPM Follow-up Work**	**Actual Number of Pole Rotten OMT Events**	**Actual Number of Crossarm OMT Events**
2009	0.1863468	13,161	7,538	44	25
2010	0.19916836	15,553	7,904	37	23
2011	0.202462739	13,324	28,011	35	28
2012	0.16613099	17,318	28,120	52	19
2013	0.15640942	14,364	15,214	34	18
2014	0.241571914*	11,879	14,901	55	26
2015	0.225273848*	8,157	12,072	43	23

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

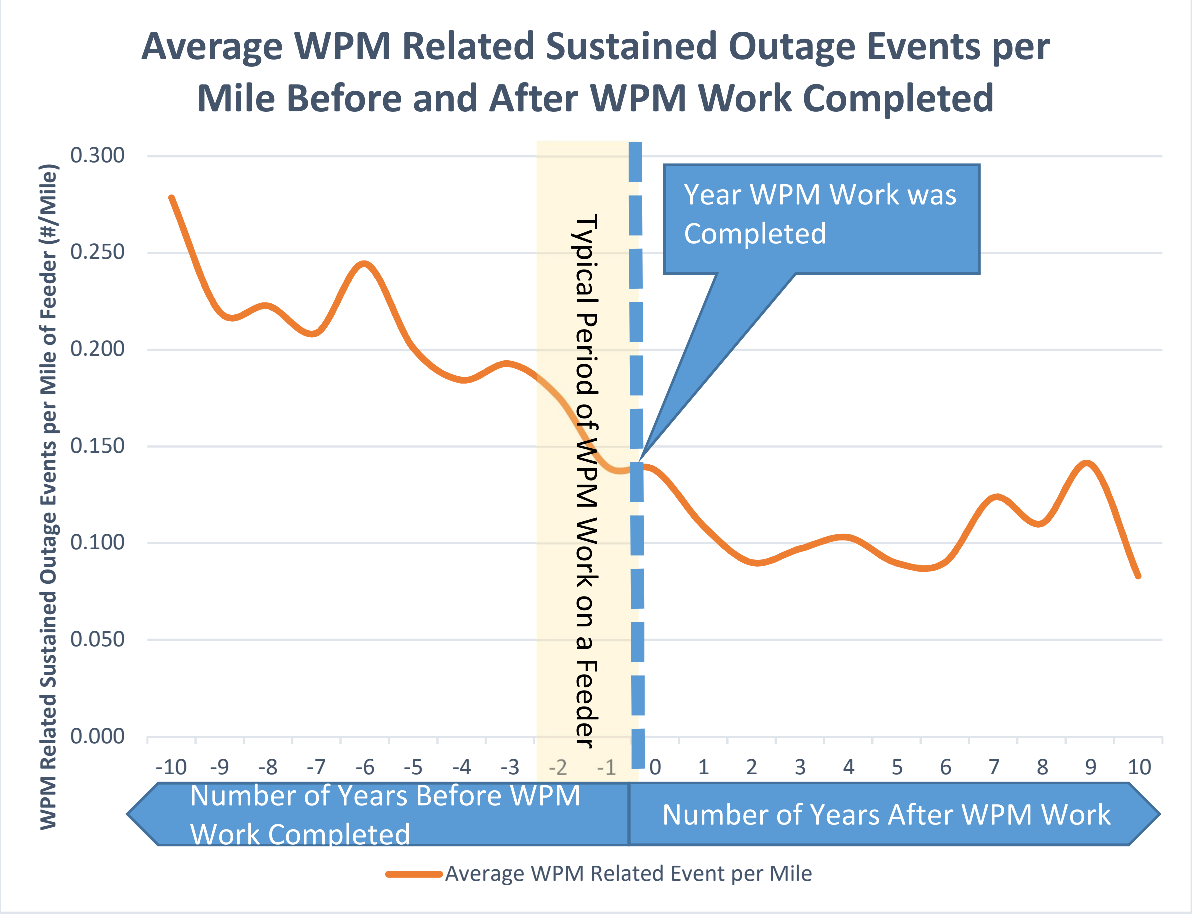
The 2017 Wood Pole Management Program and Review which is located in the c01m570 drive.

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.

Based on the analysis in 2017, the current twenty-year WPM cycle delivers the best life cycle value for the funding level. Asset Management and Distribution Engineering monitor system reliability to determine if adjustments are needed in the future. For perspective the industry average for inspecting and maintaining distribution assets is ten years.

WPM is an ongoing cyclical program that proactively replaces aging assets. By replacing assets before they fail, outage risks are reduced, and replacement costs are reduced through planned work. Investing in the infrastructure increases life-cycle performance and is cost effective using unit-based pricing. Figure 3 below shows the significant improvement in "events per mile of feeder" resulting from this program. The peak of events per mile shown in the graph is from approximately six years ago when there were nearly 1.5 events per mile. The results after the program show performance as low as .3 events per mile of feeder, a significant improvement.

If funding were to be reduced, expected outages would increase. The team would need to prioritize which components would be replaced and which would be left. This would increase the likelihood that crews would need to revisit the same pole later if a remaining component were to fail. While the five-year cycle does provide a better Customer Internal Rate of Return of 8.85%, the five-year cycle O&M costs exceeded our historical spending constraint. The internal rate of return for a twenty-year cycle is 8.00%.

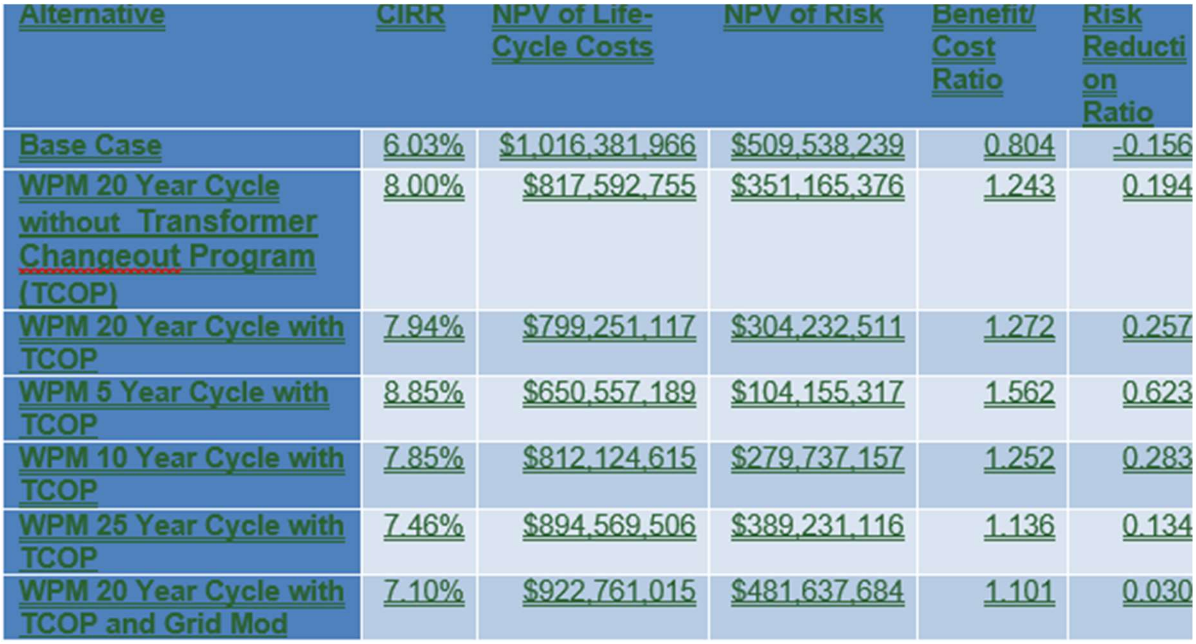


Option	Capital Cost	Start	Complete

[Recommended Solution]: Distribution Wood Pole Management Program inspects all feeders on a twenty year cycle and replaces wood poles, crossarms, missing lightning arresters, missing/stolen grounds, bad cutouts, bad insulators, leaking transformers, replace guy wires not meeting current code requirements when the pole is replaced. This includes increasing the pole inspections and replacement work for the next ten years to meet the requirements of the WUI program.	$16,739,331	01 2021	12 2030
[Alternative #1] Distribution Wood Pole Management Program inspects all feeders on a twenty year cycle and repairs and replaces wood poles, crossarms, missing lightning arresters, missing/stolen grounds, bad cutouts, bad insulators, leaking transformers, replace guy wires not meeting current code requirements when the pole is replaced. This alternative will push the WPM cycle out to twenty-three years until 2030 as WUI will compete for the same inspection and replacement costs for the next ten years.	$12,847,800	01 2021	Annually/indefinite
[Alternative #2] Do nothing-increase OMT events by 1,700 per year and increased fire risk.	$0	MMYYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

In Asset Management's 2017 Wood Pole Management Review and Recommendations several alternatives were examined that included a five-year, ten-year, twenty year, and twenty-five year inspection cycle time as well as the impact of GMP work on the related WPM work. While the five-year cycle did provide a better Customer Internal Rate of Return of 8.85%, the five-year cycle O&M costs exceeded our historical spending constraint.



Alternative	CIRR	NPV of Life-Cycle Costs	NPV of Risk	Benefit/ Cost Ratio	Risk Reduction Ratio
Base Case	6.03%	$1,016,381,966	$509,538,239	0.804	-0.156
WPM 20 Year Cycle without Transformer Changeout Program (TCOP)	8.00%	$817,592,755	$351,165,376	1.243	0.194
WPM 20 Year Cycle with TCOP	7.94%	$799,251,117	$304,232,511	1.272	0.257
WPM 5 Year Cycle with TCOP	8.85%	$650,557,189	$104,155,317	1.562	0.623
WPM 10 Year Cycle with TCOP	7.85%	$812,124,615	$279,737,157	1.252	0.283
WPM 25 Year Cycle with TCOP	7.46%	$894,569,506	$389,231,116	1.136	0.134
WPM 20 Year Cycle with TCOP and Grid Mod	7.10%	$922,761,015	$481,637,684	1.101	0.030

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 WPM program is an ongoing process of inspecting, designing, and completing replacement work of assets identified for replacement during the inspection process. The poles on the feeders in the work plan are at various phases of the process throughout the year. The goal is to complete any identified work on a feeder within eighteen months of inspection, and we currently average about one year from start to finish. This work is incorporated into workplans and allows the company to efficiently utilize resources.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Additional WUI design demand, plus increasing the work to meet the twenty-year cycle goal increases the need for additional WPM design, tech, and construction resources. Material availability can also impact the ability to execute on the plan.

Additional departments the WPM program interfaces with will also see some increase in workload which includes: Distribution Engineering, Supply Chain, Environmental, Real Estate, and out-of-cycle Vegetation Management response. There is also a strong need for Asset Management to continue reviewing and analyzing the data that supports this program.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

In Asset Management's 2017 Wood Pole Management Review and Recommendations:

> *"Asset Management examined several alternatives that included a 5-year, 10-year, 20 year, and 25-year inspection cycle time as well as the impact of Grid Modernization work on the related Wood Pole Management work. While the 5-year cycle did provide a better Customer Internal Rate of Return of 8.85%, the 5-year cycle Operations and Maintenance costs exceeded our historical spending constraint. The 20-year inspection cycle provided the best Customer Internal Rate of return and our current practice of replacing transformers that functionally have failed while meeting the Operating and Maintenance budget constraints.*
>
> *Any delays in implementing the Wood Pole Management program strategy as envisioned will delay the immediate benefits and take 20 years based on the current inspection cycle to recover the long-range value of the strategy.*
>
> *We recommend continuing the Wood Pole Management program on its 20-year inspection cycle and follow-up work strategy. Any delays in the work will impact reliability and system performance. "*

Choosing the recommended solution keeps WPM and WUI on track to be completed on time. Choosing Alternative #1 pushes the cycle out further to twenty-three years which increases the risk of more OMT events, increased O&M costs, increased possibility of a fire, and reduces the overall effectiveness of how we manage our aging assets. We also add risk by underfunding our commitment of providing safe, reliable, electric service to our customers. This work has been approved and validated in previous commission responses.

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. spend, and transfers to plant by year.

WPM is an ongoing program. The work is a continuous process of inspecting Avista's poles on a feeder basis. Each feeder represents a project within the program. There are several phases to complete each feeder including inspecting, designing, and capital follow-up. As soon as any capital follow-up work is completed, the asset can become used and useful. The transfers to plant occur on a monthly basis. In addition, our Finance Department preps the AVA_Plan system periodically for a spend and transfer to plant forecast update for the remainder of the year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This business case improves safety for our customers, employees, and the general public by responsibly mitigating safety hazards. This will also improve reliability, reduce fire risk, and decrease the number of unplanned O&M outage responses. Our company's vision is supported by building reliable infrastructure and then maintaining the assets in a safe reliable condition that improves our customers lives. The public utility commissions and our customers hold us to the highest standard of care. When we act prudently and follow through with our commitments, we demonstrate our trustworthiness.

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

The requested amount is a prudent investment to maintain Avista's overhead electric system on a twenty-year cycle, which is also in alignment with the NESC requirement to inspect and maintain our facilities in a timely manner. This work reduces the company's risk.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electric customers, Distribution Engineering, Environmental, Wildland Urban Interface, area offices, line crews, Asset Management, and Grid Modernization. Please note that with the sunsetting of the TCOP program the internal crews incorporate WPM as part of their workplan.

2.8.2 Identify any related Business Cases

Grid Modernization Program, WSDOT Control Zone Mitigation, and WUI-Wildfire Urban Interface Program.

3.1 Steering Committee or Advisory Group Information

Asset Management and Distribution Engineering provide ongoing analysis of distribution asset condition. The analysis is used to direct the WPM work that includes inspecting and maintaining Avista's poles, hardware, and equipment on a twenty-year cycle. The twenty-year cycle is documented in the 2017 Wood Pole Management Review and Recommendations. The operating guidelines are documented in the Structure Specific DMFP.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance process is a collaborative process that includes leadership from: Asset Management Asset Maintenance, Distribution Engineering, the Director of Operations, and the WPM Program Manager and WPM inspectors . The operating guidelines are documented in the Structure Specific Distribution Feeder Management Plan. The yearly goals are documented and updated on the annual one pager.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

WPM is a long-standing program that is well established. There are few change orders, but they are documented by the inspectors during the audit process. All significant change requests are reviewed by the Program Manager for approval. In cases where scope is re-evaluated, changes are agreed to prior to construction.

The undersigned acknowledge they have reviewed the *Wood Pole Management 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: Mark S. Gabert Date: 7/30/20
Print Name: Mark S Gabert
Title: WPM/WSDOT Program Manager
Role: Business Case Owner

Signature: David Howell Date: 8/2/20
Print Name: David Howell
Title: Director of Operations
Role: Business Case Sponsor

Signature: Alicia Gibbs Date: 8/2/2020
Print Name: Alicia Gibbs
Title: Asset Maintenance Manager
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

WSDOT Control Zone Mitigation

EXECUTIVE SUMMARY

This program was developed to mitigate the poles identified to be in the control zones within Washington State highway rights of way. Twenty-nine of Avista's thirty-five WSDOT Franchise Agreements have expired, and as part of renewing the agreements, the poles located within the control zone must be moved to meet the WSDOT Control Zone requirements. There are 950 pole locations that must be mitigated as part of this plan. However, movement of the identified poles will impact neighboring poles. In 2020 the Control Zone Steering Committee worked to create a plan to mitigate this issue which led to this business case.

The impacted poles have been identified and documented in Avista's AFM system. This allows designs to be completed based on the Steering Committee approved ranking methodology. Solutions to this issue include moving poles to the back of the right of way, to private easements, or overhead to underground conversions. The projects are ranked by the Risk Reduction Credits assigned to each project in order to mitigate higher-risk projects first. The cost of the solution is based on an average of the three proposed solutions for each project. The overall average cost per year is $2.7M for the next five years and is documented in the Business Case Funds Request. This program is designed to meet the WSDOT Clear Zone requirements and allow Avista to obtain the necessary permitting to maintain its facilities in a timely manner. The risks of not approving this business case means our facilities will be maintained in a run to failure mode as identified rejected poles are not replaced in a timely manner, wildland urban interface (WUI) required retrofitting may not take place, and potential car-hit-poles are left in place until failure. This program helps ensure that Avista's poles are inspected and maintained within its current twenty-year cycle. Finally, The National Electrical Safety Code (NESC) is adopted as Washington Law under WAC 296-45-045. Part 013C describes the application, Part 121 defines the required inspection interval, and Part 214A identifies required documentation and correction of the pole inspection results.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Mark Gabert*	*Initial draft of original business case*	*7/10/2020*	
2.0	*Mark Gabert*	*Final Draft of original business case*	*7/31/2020*	

WSDOT Control Zone Mitigation

GENERAL INFORMATION

Requested Spend Amount	$13,500,000
Requested Spend Time Period	*5 Years*
Requesting Organization/Department	Asset Maintenance/WPM
Business Case Owner | Sponsor	Mark Gabert | Alicia Gibbs | David Howell
Sponsor Organization/Department	M51/WPM
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The state of Washington Strategic Highway Safety Plan (SHSP) establishes strategies to reduce traffic fatalities and serious injuries along state highways and identifies utility objects, specifically utility poles, as significant roadside hazards. Twenty-nine of Avista's thirty-five WSDOT Franchise Agreements have expired, and as part of renewing the Agreements, the poles located within the control zone must be moved or otherwise mitigated to meet WSDOT Control Zone requirements.

Avista will be granted a new Franchise Agreement when we submit our Utility Object Relocation Record (UORR) plan for mitigating the control zone poles with our franchise application, and if approved, the franchise is granted on the premise that we will complete the mitigation within the specified timeframe according to our UORR. There are 950 poles that need to be moved as part of this plan, but as the identified poles are moved, this impacts neighboring poles due to the necessary reconfiguration of the line. WSDOT will not issue any permits for any routine asset replacement work until Avista addresses the out-of-compliance poles. This means we currently operate our facilities in emergency situations only.

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 major driver for this business case is Mandatory and Compliance. This driver is because we have existing overhead facilities within expired WSDOT franchise agreement right of ways (ROWs). Due to the expired franchise agreements, our overhead facilities are currently being maintained in emergency situations. Any other work requires poles located in the CZ to be moved. By renewing our WSDOT Franchises, Avista will retain the ability to maintain its assets ensuring a high level of customer service and a reduction in potential outages caused by pole failures.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The work is needed now because: leaving known poles within the control zone (and thus out of compliance with WSDOT franchise requirements), allowing rejected poles to continue to be in service, and not replacing other overhead assets that have reached end of life significantly increases our risk and exposure to unexpected failures, customer outages, and litigation. Additional risks include increased O&M expenses due to unplanned replacements, potential fire risk and associated costs of response, decreased reliability, and increased safety hazards to the public and employees. Finally, Avista's overhead assets on WDSOT ROWs are not currently being maintained on a twenty-year cycle which also increases the risk of unsafe facilities.

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.

This project is broken up into segments based on the highway name. These segments are no more than five miles of continuous pole line. We must submit the designs and mitigation plans to the state, and then complete the work within a specific timeframe. As each of these segments are completed it enables Avista to successfully obtain a new franchise agreement from WSDOT. Over time, OMT data should reflect reduced unplanned outages and the time crews spend on unplanned maintenance. In addition, the distribution Feeder Status Report should show an improvement in feeder health.

Supplemental Information

1.4.1 Please reference and summarize any studies that support the problem

Currently Avista's assets, located in WSDOT ROW, are being maintained beyond the recommended twenty-year cycle. The twenty-year cycle is based on previous analysis and timeframe to which Avista is committed.[1] The poles that must be moved are also tracked in Avista's AFM system.

1.4.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

This is a Mandatory and Compliance business driver. It is mandatory asset maintenance in order to meet the WSDOT Control Zone requirements. The work is also required to keep pace with the aging assets and expected failure rate. Figure 1 below shows the increased rate at which the poles are reaching the seventy-five-year end of life. If this business case is not approved, the aging infrastructure will cause an increasing rate of failures leading to increased outages and higher construction costs.

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[1] This analysis is documented in the 2017 Wood Pole Management Program Review and Recommendations, available upon request.

WSDOT Control Zone Mitigation

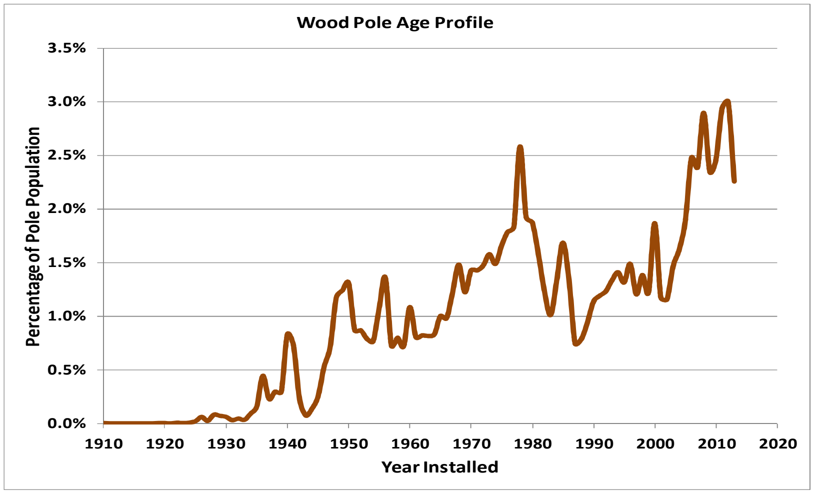


Figure 1. Wood Pole Age Profile

Option	Capital Cost	Start	Complete
RECOMMENDED: Mitigate poles in the WSDOT Control Zone	$13,500,000	01/2021	All CZ Poles Mitigated
NOT FUNDED*: Increased outages, increased O&M, increased risk to the public and employees.*	*$0*		
There are no other alternatives for this issue	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

This is a Mandatory and Compliance project to mitigate poles within the WSDOT control zone. The capital request is based on the number of poles in the control zone, number of rejected poles on WSDOT ROW, poles in WUI Tiers, control zone category, and land type. The mitigation funding is based on an estimated average of three different design possibilities including moving poles to the back of ROW, undergrounding, and private easement. The cost to mitigate each segment will depend on the design chosen by the Steering Committee.

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 capital funds will support designing, reviewing the design alternatives, obtaining Steering Committee approval, surveying, reviewing plan and profile drawings, obtaining WSDOT design approval, and then re-building as designed. By completing this work, the overall unplanned O&M maintenance costs required to replace failed poles, equipment, or hardware such as cross arms attached to the pole will be reduced.

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 business case will impact the Real Estate Department workload (including permitting, surveying, and drafting resources). If necessary, additional internal or contract resources may be needed to meet timelines for this critical work. This WSDOT Project does not have dedicated design resources so that function will also need to be addressed. Additionally, it is expected the WSDOT will also have staffing issues due to increased workload as a result of these requests. It will be important for Avista to continue to provide designed permit requests to show progress in meeting the Control Zone requirement. This will reduce Avista’s liability if reasonable solutions are provided to the WSDOT for approval and Franchise renewal.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

- **Recommended alternative**: Mitigating poles in the WSDOT Control Zone reduces failure risks over time by replacing our out-of-compliance and end-of-life assets in a timely manner. If we can show prudency by documenting the inspection and capital replacement process, we also reduce the exposure to any potential litigation.

- **Not funded alternative**: Poles and equipment will be managed in a run-to-failure mode and replaced with O&M dollars, many times at an overtime rate. If the failed asset caused any customer, employee, or the general public harm, our Claims Department would be required to attempt to mitigate any liability issues.

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. spend, and transfers to plant by year.

If funded, this project will start in 2021 and continue until at least 2025 or until all Control Zone poles have been mitigated. The timeline will also depend on the efficiency of each phase of the process. The capital construction work for each segment cannot begin until Avista completes its designs and supporting documentation for Franchise renewal. Once that is completed, WSDOT will review, and if approved, issue a permit for the work. The investment will become “used and useful” once construction of each segment has been completed. Because the segments are 5 miles or less in size once the work is approved it should be completed in 6 months or less.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This business case improves safety for our customers, employees, and the general public by responsibly mitigating known safety hazards. This will also improve reliability, reduce fire risk, and decrease the number of unplanned O&M outage responses. The work will be completed in a collaborative manner with approval from the Steering Committee. Our company’s vision starts with building reliable infrastructure and then maintaining the assets in a safe reliable condition that improves our customers lives. The WUTC, WSDOT, and our customers hold us to the highest standard of care. When we act prudently and follow through with our commitments, we demonstrate our trustworthiness.

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

The requested amount is prudent to mitigate any out of compliance poles in WSDOT ROW. The investment and progress will be reviewed on a quarterly basis with the WSDOT Control Zone Mitigation Steering Committee. This is an on-going meeting to ensure that Avista meets the goal of successfully securing new Franchise Agreements for the 29 Franchises that have expired.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Real Estate is a major stakeholder and is responsible for ensuring the Franchise Agreements are up-to-date and that our facilities, assets and work are in compliance with Franchise Agreements. The WSDOT is responsible to work with utilities to help mitigate this issue. Our internal and external customers benefit from this business case as hazardous assets are replaced and new Franchise Agreements are secured to enable programmatic replacement of facilities on a twenty-year cycle.

2.8.2 Identify any related Business Cases

Wood Pole Management is related to this from an asset condition perspective, but Wood Pole Management was not funded to relocate pole lines in the way the Grid Mod Program was funded. This business case replaces ER2064 which was previously approved to mitigate this issue.

3.1 Steering Committee or Advisory Group Information

The WSDOT Steering Committee includes Alicia Gibbs, Rod Price, Bob Brandkamp, and Mark Gabert.

3.2 Provide and discuss the governance processes and people that will provide oversight

The WSDOT control zone mitigation committee must approve the plan prior to commencement.

How will decision-making, prioritization, and change requests be documented and monitored

The design decision and review will come from the program manager and the WSDOT control zone mitigation steering committee**.** This should eliminate most, change requests. Any construction of the work utilizing internal resources does not require a change order and designs will include local office input if cost effective. Any work completed by contract crews may be completed under a unit-based pricing contract, and the units are sufficient to minimize most change requests. If the job is large enough and local crews are not available, then a lump sum contract could be considered.

WSDOT Control Zone Mitigation

The undersigned acknowledge they have reviewed WSDOT Control Zone Mitigation 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: Mark S. Gabert
Date: 7/30/2020
Print Name: Mark S. Gabert
Title: WPM/WSDOT PM
Role: Business Case Owner

Signature: David Howell
Date: 8/2/20
Print Name: David Howell
Title: Director
Role: Business Case Sponsor

Signature:
Date:
Print Name: Alicia Gibbs
Title: AM Manager
Role: Steering Committee Review

Template Version: 05/28/2020

Apprentice_Craft Training

EXECUTIVE SUMMARY

Avista manages 11 Federally regulated apprenticeships that require instructional aides and equipment deemed necessary to provide quality instruction. [Regulated by 29 CFR 29 & 30] The Joint Apprenticeship Training Committee (JATC) administers these apprenticeships. These funds are used to purchase tools, materials and equipment for training apprentices and journey workers in all crafts. These tools and materials provide for related instruction that is closely correlated with the practical experience and training received on the job. The trained and competent workforce produced through the various apprenticeship's benefits customers in all Avista service territories. These apprenticeship programs further benefit Avista's customers by providing a safe, proficient and skilled workforce.

Support of apprenticeship at Avista through this capital program aligns strategically to Avista's Mission and Focus Areas. In order to deliver innovative energy solutions safely, responsibly, and affordably, Avista must have a field workforce of highly proficient professionals. This professionalism is achieved through apprenticeship. Without this funding, Avista will not have the ability to train in-house. This leaves Avista's customers without critical craft positions needed for energy delivery. Further, there is a potential that regulating bodies may de-certify Avista's Apprentice program, leaving Avista without the ability to train in-house and require significant expense to meet labor demands and maintain required skillsets. This project will train apprentices in all Avista states and service territories, the rate jurisdiction is Common Direct – Allocated All. The total capital expense to support this ongoing project is $375,000 over 5 years or $75,000/year.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Joe Brown*	*Executive Summary Only*	*7/1/2020*	*Business Case 2020 Refresh*
1.0	*Joe Brown*	*Updated for Approval*	*7/28/2020*	*Full amount approved*
1.1	*Joe Brown*	*Reviewed for Approval*	*7/13/2021*	*No Changes Required*

GENERAL INFORMATION

Requested Spend Amount	$375,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	Craft Training [I02]
Business Case Owner | Sponsor	Joe Brown | Jeremy Gall
Sponsor Organization/Department	Human Resources
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

This capital program provides for tools, materials and equipment for training apprentices and journey workers across eleven skilled crafts or trades. This training consists of hands-on skills development that builds competency in a safe learning environment that may not always be available or controllable in the field. A well trained and competent workforce ensures reliable delivery of energy to Avista's customers and maintains a safe environment for employees, customers and the general public in all Avista Utilities service territories. Being unable to provide these needed tools, materials and equipment leaves apprentices and journeyman without the resources needed for their related instruction.

As stated previously, support of apprenticeship at Avista through this capital program aligns strategically to Avista's Mission and Focus Areas. In order to deliver innovative energy solutions safely, responsibly, and affordably, Avista must have a field workforce of highly proficient professional. In addition to creating a safe and skilled workforce, this training helps Avista to deliver timely training on new and emerging technologies as well as meet several federal and state mandated regulations including:

- Department of Labor, Standards of Apprenticeship – Title 29 CFR 29.5 (b)(4) and (b)(9) – Apprentice on the job training and related instruction
- Department of Labor, Occupational Safety and Health Standards – Title 29 CFR 1910.269 (a)(2) – Electric Power Generation, Transmission, and Distribution training
- Department of Transportation, Transportation of Natural Gas and Gas by Pipeline: Minimum Federal Safety Standards - Title 49 CFR 192.805 (h) – Qualification of Pipeline Personnel, Qualification Program training
- State of Washington – WAC 480-93-013 (4) – Covered Tasks: Equipment and facilities used by pipeline company for training and qualification of employees

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 primary driver of this business case is Mandatory & Compliance with the secondary drivers being Customer Service Quality & Reliability and Performance & Capacity. Avista must meet comply with the laws, rules and regulations associated with apprenticeship. Further, customer service and asset performance will benefit from a highly skilled workforce.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Avista will not have the ability to train in-house if this program is not funded. This leaves Avista's customers without critical craft positions needed for energy delivery. Further, there is a potential that regulating bodies may de-certify Avista's Apprentice program, leaving Avista without the ability to train in-house and require significant expense to meet labor demands and maintain required skillsets.

1.4 Supplemental Information

1.4.1 Please reference and summarize any studies that support the problem

The cost to outsource hands-on-training and field simulations would be approximately $473,000 a year for facility rental alone. This is based on current training programs that have averaged over 530 hours per year at the training center. The overall annual costs including travel, lodging, meals and registration are estimated to more than triple this rental cost and be classified as operations and maintenance costs. It is estimated this total cost would be approximately $2.4M in O&M expense over 5-years. Again, this would result in a negative impact to Avista's customers

1.4.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

NA

The recommended solution (Option 1) is to provide the resources needed for related instruction of craft personnel.

Option	Capital Cost	Start	Complete
1. On-Going Capital Improvement Program	*$375,000*	*01 2021*	*12 2025*
2. Outsource Training [No Facility]	*$2.4M (O&M)*	*01 2021*	*12 2025*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The cost to outsource hands-on-training and field simulations would be approximately $473,000 a year for facility rental alone. This is based on current training programs that have averaged over 530 hours per year at the training center. The overall annual costs including travel, lodging, meals and registration are estimated to more than triple this rental cost and be classified as O&M costs.

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.

Under this program, projects could include items such as building new facilities or expanding existing facilities, purchase of equipment needed, or build out of realistic utility field infrastructure used to train employees. Examples include new or expanded shops, truck canopy, classrooms, backhoes and other equipment, build out of "SmartCity"- commercial and residential building replicas, and distribution, transmission, smart grid, metering, gas and substation infrastructure.

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 greatest impact will be seen by Avista's Operations and Avista's Customers. Operations will have employees with the knowledge and skills to do their jobs professionally, and customers will be served by these competent professionals.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The primarily alternative for this program is to outsource training. If this is done, at great expense, there will be significant impact on operating budgets, company culture, and possibly labor relations.

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. spend, and transfers to plant by year.

The projects associated with this business case will be planned on an annual basis and be used and useful during the calendar year in which they are implemented.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Support of apprenticeship at Avista through this capital program aligns strategically to Avista's Mission and Focus Areas. In order to deliver innovative energy solutions safely, responsibly, and affordably, Avista must have a field workforce of highly proficient professionals. This professionalism is achieved through apprenticeship. This is an investment in Our People. Providing Avista's employees with the tools, equipment and materials they need to train in a safe, simulated environment is essential: This is an investment in the people of Avista and allows these apprentices to deliver value to customers and the communities they serve.

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

Apprentices are the future workforce of Avista. Ensuring that they have the facilities, equipment, tools and materials they need to become successful journeyman is an investment in the future. Taking care now to invest in the future workforce will benefit Avista's customers and operations.

This project will be evaluated annually in the Craft Training Department and ensure projects of the highest need area addressed.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The key stakeholders associated with this business case are primarily internal Avista employees and departments.

2.8.2 Identify any related Business Cases

NA

3.1 Steering Committee or Advisory Group Information

As part of the Craft Training annual planning process, the list of projects for apprenticeships will be established, vetted and managed within the department. The manager of Craft Training & OQ will be accountable for the business case and annual funding.

3.2 Provide and discuss the governance processes and people that will provide oversight

Oversight will be provided by the Manager of Craft Training & OQ, and through periodic meetings with the Sr. Manager of Safety & Craft Training.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The manager of Craft Training & OQ will be accountable for making decisions on the business case in coordination with the Sr. Manager of Safety & Craft Training.

Apprentice_Craft Training

The undersigned acknowledge they have reviewed the *Apprentice Craft Training 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: Joe Brown Date: 7/13/2021
Print Name: Joe Brown
Title: Mgr Craft Training & OQ
Role: Business Case Owner

Signature: Date: 7/19/2021
Print Name: Jeremy Gall
Title: Sr. Mgr Safety & Craft Training
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Capital Equipment Program (ER7005/7006)

EXECUTIVE SUMMARY

The Capital Equipment Program (ER7005/7006) funds the essential tools required for Avista employees to perform work efficiently and safely. This equipment is necessary to construct, monitor, ensure system integrity, and properly repair and maintain the Avista systems (electric, gas, communications, fleet, facilities, and generation). This equipment needs to be fully functional and available for planned work as well as emergency outage repairs on our facilities and equipment. Capital tools are utilized in all service territories, and by all Crafts. Capital tools are required to execute and support work across all business units and it is recommended to continue to fund these tools at an annual level of $2.4M for 2021 and then escalated for inflation and increase technology ($100k) each year for the five year plan.

Capital tools benefit customers by reducing labor cost due to improved efficiency and improving quality of the work by advanced performance of the tools. Customer will also benefit from improved system reliability and reduced outage duration enabled by diagnostic tools. It is critical that capital tools are consistently and adequately funded year over year to maintain performance and ensure tool availability. The risk of not funding capital tools is reduced work performance, increased safety risk, reduced work quality, and increased outage time for customers.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Daisy Drafter*	*Initial draft of original business case*	*4/15/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0	*Cody Krogh*	*Updated plan to new outline*	*7/13/2020*	

GENERAL INFORMATION

Requested Spend Amount	$ 2,400,000
Requested Spend Time Period	5 years
Requesting Organization/Department	Supply Chain
Business Case Owner | Sponsor	Cody Krogh | Dan Johnson
Sponsor Organization/Department	H51 / Supply Chain
Phase	Monitor/Control
Category	Program
Driver	Asset Condition

Capital Equipment Program (ER7005/7006)

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?

Each year, the Capital Equipment Program has more requests for tools and equipment than can be funded. The funding deficit prevents the purchase of all submitted requests. In addition, there is a trend of decreased funding for the capital tools. Over this same time period, the tool complement has been expanding by replacing manual tools with battery assist devices to increase safety and productivity. These additional tools will require more funding, over time, to support replacement costs, as well as ensure all areas of the company can take advantage of this technology.

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 Capital Equipment Program (ER7005/7006) funds the essential tools required for Avista employees to perform work efficiently and safely. This equipment is necessary to construct, monitor, ensure system integrity, and properly repair and maintain the Avista systems (electric, gas, communications, fleet, facilities, and generation). Much of the capital equipment used in the utility industry is very specialized and may not be readily available due to long lead times. This equipment needs to be fully functional and available for planned work as well as emergency outage repairs on our facilities and equipment. Equipment failures contribute to injuries, slowdowns in work performance, and increased customer restoration time.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This work is needed to ensure that our workers have safe and reliable tools to complete their tasks, and also to ensure that if there are any tools that are broken, they can be replaced in a timely matter to keep projects/tasks on schedule. If this work is not approved/deferred the risks include breakage of equipment that is critical to daily operations/projects leading to longer lead times for repairs or project completion. Also, our employees need safe tools to ensure there are no injuries on the job. By having these updated through this program, we can increase our productivity by having tools that will allow us to complete our work efficiently on time and increase the safety of our employees.

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 Capital Equipment Committee (CEC) ensures that the investment successfully addresses all capital equipment requests to ensure each is warranted. The CEC also ensures that each request is prioritized based upon importance of need and equal allocation of funds for capital equipment requests.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

[List the location of any supplemental information; do not attach]

Attachment 1: Email from Tony Klutz describing the benefits of the Capital Equipment Program
Attachment 2: Scoring Criteria & Weighting
Attachment 3: Capital Equipment Committee Board Charter
Attachment 4: Capital Committee Notes

NOTE: All files are stored in the "N-Drive" under "Capital Budget", then "Business Case Folder" and then "2020 Business Case"

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.

Safety project for ergonomic related battery assist tools was widely implemented in 2016 with the addition of 44 battery assist tools. This was followed by 2017 with 75 tools, 2019 with 58 tools. This equipment has a 5 year warranty, so future failures for 5 year old equipment will not be covered by warranty. Replacements for these out of warranty tools will need to be budgeted for within the ER7006 budget each year, as per all additional "new" capital equipment.

[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, attach as supporting documentation)]

Option	Capital Cost	Start	Complete
[Recommended Solution] Option 1 (Recommended)	*$2.4 M*	*01/2018*	*NA*
Partially Fund (based on priority)	*Varies*	*01/2018*	*NA*
Rent 4% of total equipment and purchase the rest	*$2.3 M*	*01/2018*	*12/2020*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

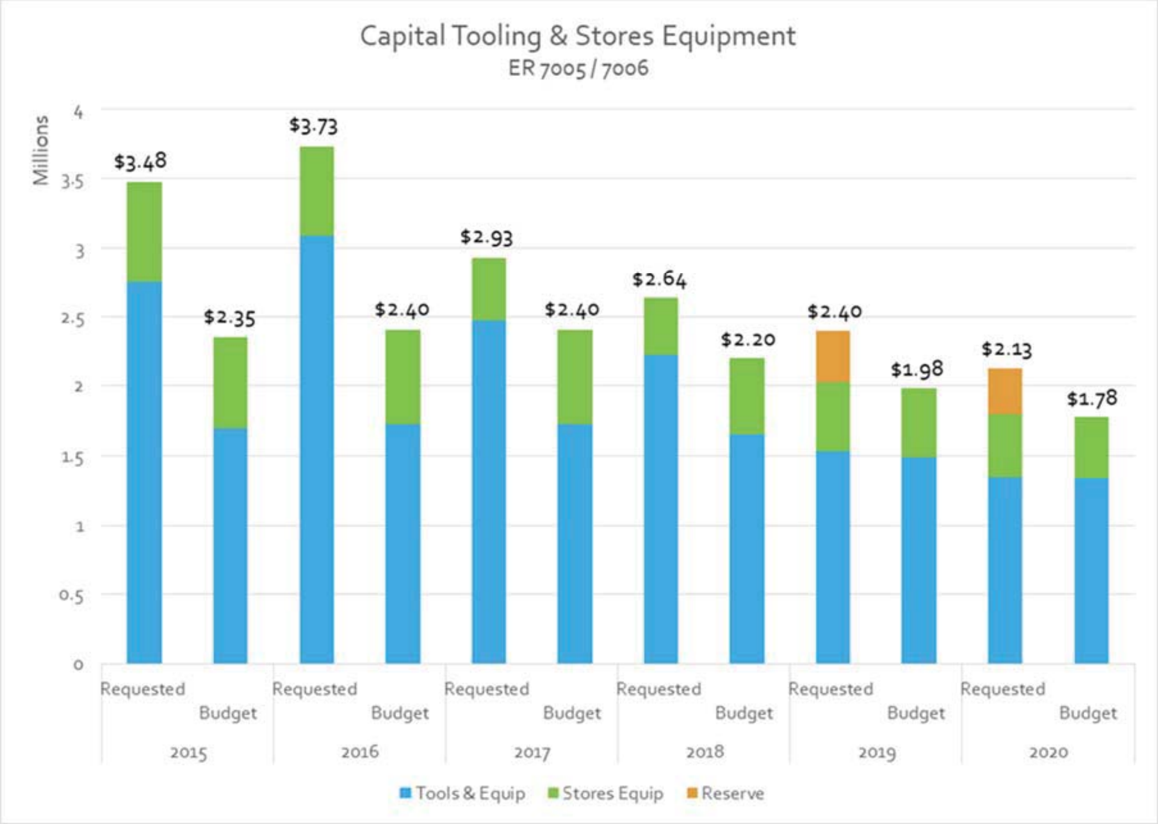
Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

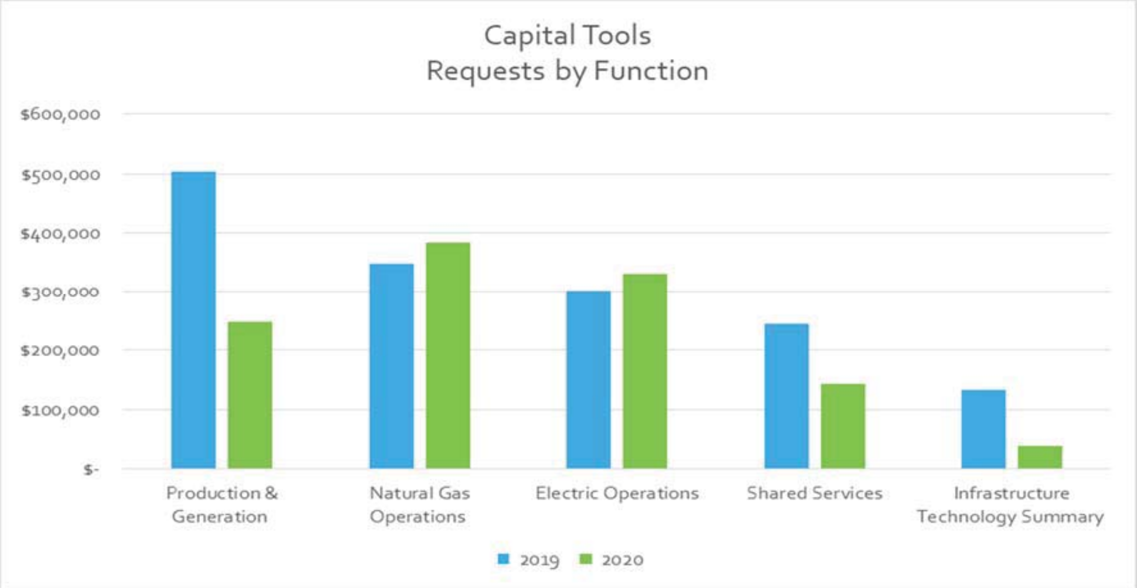
Reference key points from external documentation, list any addendums, attachments etc.

Each year, the Capital Tool Program has more requests for tools and equipment than can be funded as shown below in Figure 1. The requests are prioritized and tool selection is completed as described in Section 2.2. The funding deficit prevents the purchase of all submitted requests. In addition, there is a trend of decreased funding for the capital tools. Over this same time period, the tool complement has been expanding by replacing manual tools with battery assist devices to increase safety and productivity. These additional tools will require more funding, over time, to support replacement costs.

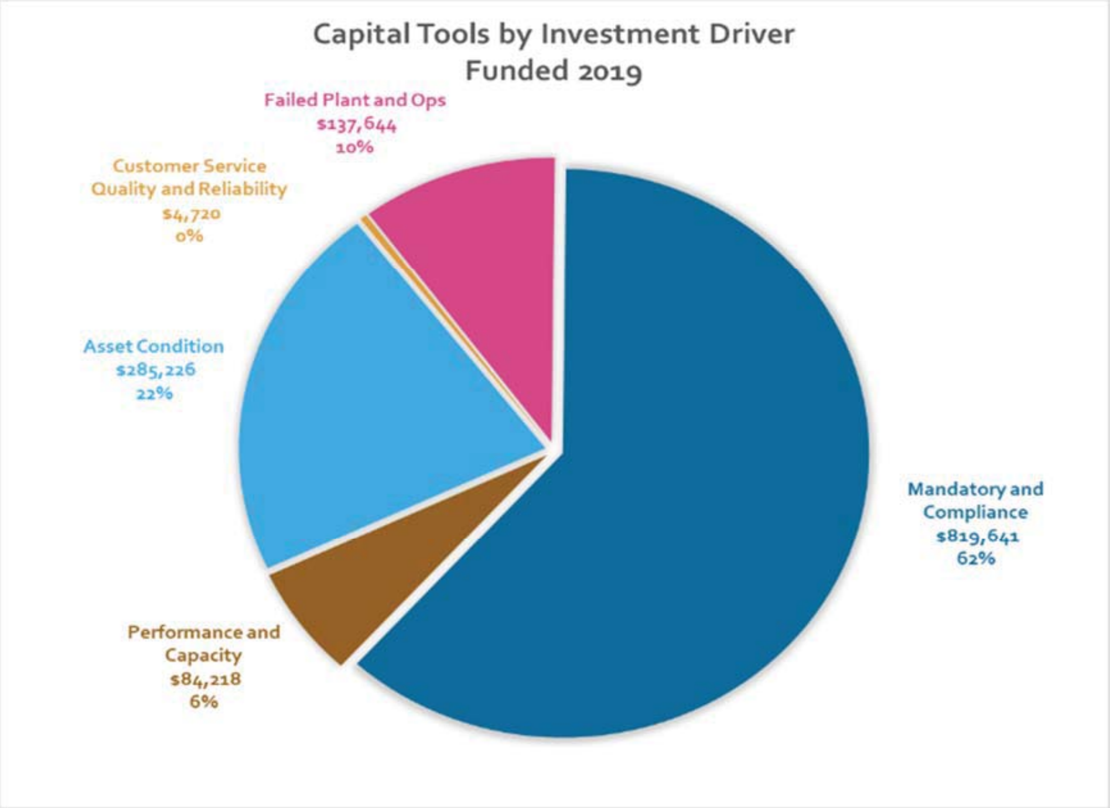
Capital Equipment Program (ER7005/7006)



The distribution of Capital Equipment funds by the Business Unit is shown below in Figure 2 (see below). The allocation is based on overall tool ranking and priority rather than a set allotment by department. As a result, there is variation year over year (as noted in the graph) ensuring that the most critical tools are funded.



The 2019 capital tool breakdown by investment driver is represented below in Figure 3. The highest percent of spend (62%) was for tools related to Safety and Compliance. This category is also the highest ranking investment driver. Spend in this area is related to changing industry complinace standards and tools identified to improve safety or ergonomics (improved body posture, reduced exertion of force, and reduction in frequency).



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.

How will the outcome of this investment result in potential additional O&M costs, employee or staffing reductions to O&M (offsets), etc.?

[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.]

An updated process was created in 2019 and is being fully implemented in 2020. The process begins by requesting Business Unit Managers to upload their tool needs into a SharePoint site. As part of the tool submittal the Manager must complete several ranking criteria used to support the business need for the tool. These criteria are Priority, Current State, Investment Driver, Strategic Alignment, Stakeholder, and Demand Type. The Managers' requests are then routed to the respective Business Unit Directors for approval. For a detailed breakdown of the criteria see reference document "Scoring Criteria & Weighting" in section 1.5.1.

The final list from each Business Unit is then reviewed by the CEC to ensure funding is distributed fairly and impartially across the company. The equipment request list is ranked per the scoring criteria ensuring all equipment is funded in order of ranking. This is required to prioritize spending as the total equipment requests exceed the allocated budget. Decision records and meeting notes are maintained on the SharePoint site once the CEC finalizes the list and purchasing is ready for execution.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

[For example, how will the outcome of this business case impact other parts of the business?]

One of the business functions that will be impacted are those areas using outdated equipment/tools. We need to replace existing tools that have failed or reached the end of their life, or have been deemed unsafe do to current safety or regulatory issues. Avista employees must be able to rely on this equipment while performing hazardous duties, and must be confident that the equipment will perform safely and efficiently. Failed equipment not in compliance with current safety standards can lead to hazardous conditions for the operators, potentially causing injury or death.

Another important priority for tool and equipment purchases is enhanced productivity. Capital equipment is used to perform new construction work or repair work for unplanned failures. Often this work can take less time or be completed quickly with better results by using improved tools.

These processes need to be implemented to not only improve the safety, but also the productivity of employees. These benefits do impact other parts of the business as work will be completed efficiently and safely, reducing delays and injuries. There are also benefits to our external customers in regard to restoration time and reliability.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Option 1 – Fund Program at Current Level (Recommended)

It is recommended that this Program be funded, annually, at its current level with a 5% annual increase to ensure Avista has the proper capital equipment necessary to safely and efficiently perform all required work. This 5% increase is to cover inflation of current pricing, support replacement equipment as complement has increase in time, and support increases in technology leading to higher equipment costs. Due to the specialized nature of utility equipment, it is most efficient for Avista to equip employees with the necessary tools and equipment to safely perform timely emergency repairs, while using the same tools and equipment to perform ongoing scheduled work and maintenance. Furthermore, this specialized equipment is often only available directly from the manufacturer, and is not typically available as a rental.

By funding this Program, Avista ensures that employees have the proper equipment to safely and efficiently perform their work, while providing safe, reliable service to customers.

Option 2 – Partially Fund Program based on priority

This option is not the preferred approach over the long-term; however, it is exercised when necessary. Each year, when the requests for tools and equipment are submitted, cuts to the Capital Equipment Program are made by the business units to bring the projected cost of the list of equipment and tools into line with the budgeted amount. Further modification of the funding level for the Program is performed in concert with other business budget needs.

When the program budget needs to be reduced, reductions are first made to requests in the category of enhanced productivity, then replacement. Replacement is intended to replace aging units to achieve more predictable capital requirements and avoid replacement peaks caused by large-scale failures. Cutting into these requests over an extended period leads to reduced efficiency and have safety impacts. This has caused excessive rollovers each year, which build up extensively when they are not able to be purchased within the current budget cycle. This leads to a buildup in capital equipment requests that cannot be adequately funded.

Having the ability to test and incorporate equipment that falls within the enhanced productivity category can help support improved processes and lead to enhanced safety and longer equipment lifecycles.

Option 3 – Rent Equipment

Renting a percentage of the capital equipment was considered as a possible alternative. Of the 430 items purchased from 2012 to 2014, 233 can be rented, although 216 out of the 233 items are needed, on hand, at all times for emergency locates and repairs. This leaves 17 possible items, or 4% of the total equipment, which qualifies as potential rental equipment (see Figure 3).

If equipment is rented, there is no guarantee of availability. Rental companies rent equipment on a first-come, first-served basis, making equipment scheduling for specific time sensitive jobs very difficult. Safety and compliance regulations are also affected when correct equipment is not available for rent.

Equipment failure is often a concern with rental equipment, as it is uncertain what condition rental equipment is in, or how it has previously been maintained. This can lead to safety issues for equipment operators when failures occur, as well as lost production time.

Depending on the timeline of the rental equipment, it would not be cost effective to rent long-term as the rental costs would exceed the base price of new equipment. An average rental price for a basic cable locator is $450/month, which equates to $5,400/year. The 2017 purchase price of this item is $3,700.

Training on rental equipment would also be required, if different than standardized Avista equipment. For example, Avista gas employees are only trained/qualified on specific equipment that has been standardized by Avista, which may or may not be what can be rented for specific jobs. This can contribute to added time necessary to qualify employees on the operation of the equipment, and safe operating procedures.

Due to the Department of Transportation (DOT) compliance, Avista is also required to maintain maintenance and calibration records for all gas equipment, along with operations guides for all on-site equipment. Avista would be out of compliance using various rental equipment as rental companies are not required to provide this documentation for their equipment to their customers.

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. spend, and transfers to plant by year.

[Describe if it is a program or project and details about how often in a year, it becomes used-and-useful. (i.e. if transfer to plant occurs monthly, quarterly or upon project completion).]

An updated process was created in 2019 and is being fully implemented in 2020. The program is projected for five (5) years to account for equipment/tool life cycle and replacements. The planning and execution of the program is managed by the Supply Chain Department. Tools are received and delivered to internal customers and immediately become used and useful, this program has been ongoing for decades. The average tool lead-time is 12-14 weeks.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

[If this is a program or compilation of discrete projects, explain the importance of the body of work.

Capital equipment benefits customers by reducing labor cost due to improved efficiency and improving quality of the work by advanced performance of the tools. Customer will also benefit from improved system reliability and reduced outage duration enabled by diagnostic tools. It is critical that capital equipment is consistently funded year over year to maintain performance and ensure equipment/tool availability. The risk of not funding capital equipment is reduced work performance, increased safety risk, and reduced work quality.

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

The funding is managed through a well-defined process with oversight from the CEC the final list from each Business Unit is then reviewed by the CEC to ensure funding is distributed fairly and impartially across the company. This is required to prioritize spending because the total tool requests exceed the allocated budget. Decision records and meeting notes are maintained on the SharePoint site. The Capital Equipment Steering Committee submits the revised list to the CPG for final approval and execution.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Internal customers would be employees such as line workers and other employees who will be using the capital tools to perform their jobs. They are also the stakeholders as some equipment will need to be replaced in order for the employees to effectively and safely complete their jobs. Our external customers also benefit from this program as they will reap the benefits of our workers increased reliability and decreased down time. With more reliability and less down time we are able to fix/repair any issues the customers may have much faster and keep our external customers satisfied with our quick service and reduced down time.

2.8.2 Identify any related Business Cases

[Including any business cases that may have been replaced by this business case]

All business cases need the proper tools in order to best utilize the labor for the completion of work benefiting our employees and customers. Examples of Business cases that utilize these tools are: Wood Pole Management, Grid Modernization and Wild Fire Resiliency.

3.1 Steering Committee or Advisory Group Information

[Please identify and describe the steering committee or advisory group for initial and ongoing vetting, as a part of your departmental prioritization process.]

The final requested tool list from each Business Unit is then reviewed by the Capital Equipment Committee (CEC) to ensure funding is distributed fairly and impartially across the company. The tool list is ranked from the scoring criteria to make certain the tools are funded in order of ranking. Ranking is required because the total tool requests exceed the allocated budget.

3.2 Provide and discuss the governance processes and people that will provide oversight

The governance process is documented in the Capital Equipment Committee Board Charter (See attachments in section 15.1). In summary it is guided by the following scoring criteria: Priority, Current State, Investment Driver, Strategic Alignment, Stakeholder, Demand Type and Age of request. Each of these scoring criteria are weighted to help place the requests in order of high to low importance.

Those who provide oversight will be those who make up the Capital Equipment Committee Board (these members are nominated annually by Directors). These members will help to ensure that the funding for capital equipment is distributed fairly and impartially based of the needs of Avista.

The following are those members that make up the board composition:

Tool Keeper (Gas):	Voting Member
Tool Keeper (Elec):	Voting Member
Safety & Health Coordinator:	Voting Member
Electric Operations Manager:	Voting Member
Gas Operations Manager:	Voting Member
Generation & Production Manager:	Voting Member
Capital Planning Group Member:	Voting Member
Supply Chain Manager:	(Non) Voting Member
Capital Equipment Sourcing Professional:	(Non) Voting Member

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Capital Equipment Committee works to ensure that the funding for capital equipment is fairly distributed, all decision-making, prioritization and change request records along with meeting notes will and are maintained on the SharePoint site as “Capital Committee Notes”. All participants in the process (Directors, managers, requesters) have access to the approvals and addition for their area via the SharePoint site. The members of the CPG are also the Directors approving the requests for their areas prior to the Cap Equipment Committee’s approval session.

Capital Equipment Program (ER7005/7006)

The undersigned acknowledge they have reviewed the Capital Equipment 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: DocuSigned by: Cody Krogh 72D171DDE3F0478... Date: Jul-29-2020 | 11:19 AM PDT
Print Name: Cody Krogh
Title: Supply Chain Manager
Role: Business Case Owner

Signature: DocuSigned by: Dan Johnson 8547E8F8CC9E4C4... Date: Jul-29-2020 | 12:56 PM PDT
Print Name: Dan Johnson
Title: Director, Shared Services
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Fleet Equipment Capital Refresh Program

EXECUTIVE SUMMARY

A 2018 Avista brand study found that 65% customers are most likely to see and identify Avista with our trucks. Our vehicles and associated gear are an essential part of our ability to address customer needs and perform work required to be an effective an efficient electric and gas utility. The Fleet Vehicle Refresh Capital Plan is the annual and ongoing plan to replace a portion of Avista's fleet in order to ensure the highest level or reliability and the lowest total cost of ownership. The annual cost of vehicles can be split into two types, direct operating and indirect costs. Direct costs include fuel and maintenance, while indirect costs include common ownership expense. Avista's replacement model is based on a proven fleet management concept that there are predictable increasing maintenance costs and decreasing ownership costs as a vehicle ages. The point at which those two lines intersect gives Avista a window of opportunity in which we will achieve the lowest total cost of ownership cost for a given unit. Replacing the unit at that time allows us to ensure a high level of reliability (96% availability currently) at the same time ensuring we have a steady and predictable level of work for the technicians in our garages. Maintaining a high reliability percentage is essential when we experience an EOP event. Over the last several years we have experience multiple large EOP events, we are extremely proud of how well our fleet has performed. The fleet experienced very few breakdowns even though our units were being used around the clock in some of the most serve conditions. This strategy also gives us the advantage of liquidating units while they still have reasonable amount of fair market value. These funds help supplement our planned spend, minimizing the need for additional funds request when market prices fluctuate.

To develop this model Avista has worked with Utilimarc, a utility focused data analytics company who benchmarks and does similar analysis for over 50 investor owned utility fleets in the US. The model inputs the initial price, actual maintenance & repair costs, depreciation expense and salvage value to establish each class of vehicle's replacement cycle. The recommended solution will replace 60-90 units per year with an average spend of $6,600,000 per year for a total five year cost of $33,300,000. The investment in Avista's fleet, over the past decade, means that we have a highly reliable fleet that meets the service level expectations that our internal customers have. Our equipment must be able to function in the most extreme situations. Our trucks can be in 120+ degree heat in the bottom of Hells Canyon or 0 degree snow storms in Sandpoint. Trucks that are running allow crews to work an outage and reenergize/repressurize the system. By spending a level amount of capital every year, we are able to maintain a constant average fleet age which produces a known quantity of work in our shop and it prevents us from having a bubble of trucks that create budget issues in later years. Those bubbles create workflow issues for technicians and the maintenance supervisors as well as the employees who purchase vehicles. The investment made has meant that we are a highly reliable and highly functional tool for our crews. We have maximized our value while minimizing our total cost. By failing to fund this program we create a growing cost of repair expense and a decreasing level of reliability/availability.
Service Code and Jurisdiction of Customer Impacted
Common Direct, Electric Direct, Gas Direct
Allocated North, Washington, Oregon, Idaho

VERSION HISTORY

Version	Author	Description	Date	Notes
ExeSum	Greg Loew	Initial executive summary submittal	7/10/20	
Rev 1	Greg Loew	Completed case	7/24/20	

Fleet Equipment Capital Refresh Program

Rev 2	Loew & Potter	2021 update	7/2/21	

GENERAL INFORMATION

Requested Spend Amount	$33,400,000
Requested Spend Time Period	5 years
Requesting Organization/Department	Fleet Services
Business Case Owner | Sponsor	Greg Loew | Alicia Gibbs
Sponsor Organization/Department	Energy Delivery
Phase	Execution
Category	Program
Driver	Asset Condition

Fleet Equipment Capital Refresh Program

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Trucks and equipment do not age well. Fleet vehicles experience a duty cycle that most vehicle owners would not imagine for their personal car or truck. Avista's fleet of vehicles operate in environments that are often at the extreme of whatever scale you are looking at, extreme heat, cold, or the dustiest of environments. These vehicles also experience employees constantly entering, and exiting, while the engines experience high idle time or high loads. These factors all contribute to the wear and tear our vehicles and can create substantial demand for repair workorders. This kind of duty cycle over the life of a truck will add up to an increasing amount of repair work and a lower reliability factor as a vehicle ages. By building a replacement program we optimize our vehicle life so that we extract the right amount of useful value from our vehicles before they experience a rapidly growing amount of repair expenses. The program we have built affords us the ability to plan our labor and maximize our internal mechanic resources while having a fleet of vehicles that are available for any job; planned or unplanned operational response.

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 Fleet Equipment Capital Refresh Program is driven by Asset Condition. This program benefits both our internal and external customers.

External customers: Our customers benefit from our Fleet Replacement Program by having a small and predictable annual portion of their bill tied to the acquisition and operation of our fleet. Additionally, new vehicles have the cleanest burning engines and advanced safety features that protect the environment and drivers on the road. A highly reliable fleet ensures that our customers will not experience a delay in getting their energy restored because our crews cannot get there.

Internal customers: Our drivers have the safest most reliable trucks as a result of the investment in our fleet. Our fleet of trucks are ready for work over 96% of the time. In the field our trucks experience fewer breakdowns per 100 hours of operations and are in the 1st quartile when compared to peer utility fleets. Our fleet of vehicles includes advanced safety features, modern efficient engines and operational tools that make many tasks more efficient. We work very hard with input from or customers to make sure we are producing units that give them what they need to serve our external customers safely, efficiently, and reliably.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The investment in vehicles for our Avista's fleet is not an option. Our crews do not get to their jobsites, near or far, in any way but in an Avista owned piece of equipment. Vehicles will break down and reach their end of life. It can be prolonged by making expensive and time-consuming repairs. The availability of the company's fleet and its field reliability will suffer if there is not an invest of capital. Additionally, the company will see a steady rising cost in maintenance both in labor and material dollars. The deferral of investment will also cause bubbles of increased capital needs in out years as the team tries to shore failed assets and work to bring the average fleet age in line with industry best practices. If we do not invest our dollars into the capital replacement plan, we will end up spending those dollars on costly repairs. Repair costs are much more, are unpredictable and make it much more difficult to forecast. In the worst case we would see at 12,000 hour gap between labor available and the labor required to complete necessary repairs experience by the replacement deferral in the coming decade. That difference would likely be met with vendor labor which carries a premium over internal labor. In 2032 that would add an additional $660,000 per year to the clearing account which would be born through significant equipment cost burdens.

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.

Our annual industry benchmarking and year of year analysis of numbers show that we are performing within the industry 50th percentile band. The number of work orders per year and maintenance cost per year have remained steady.

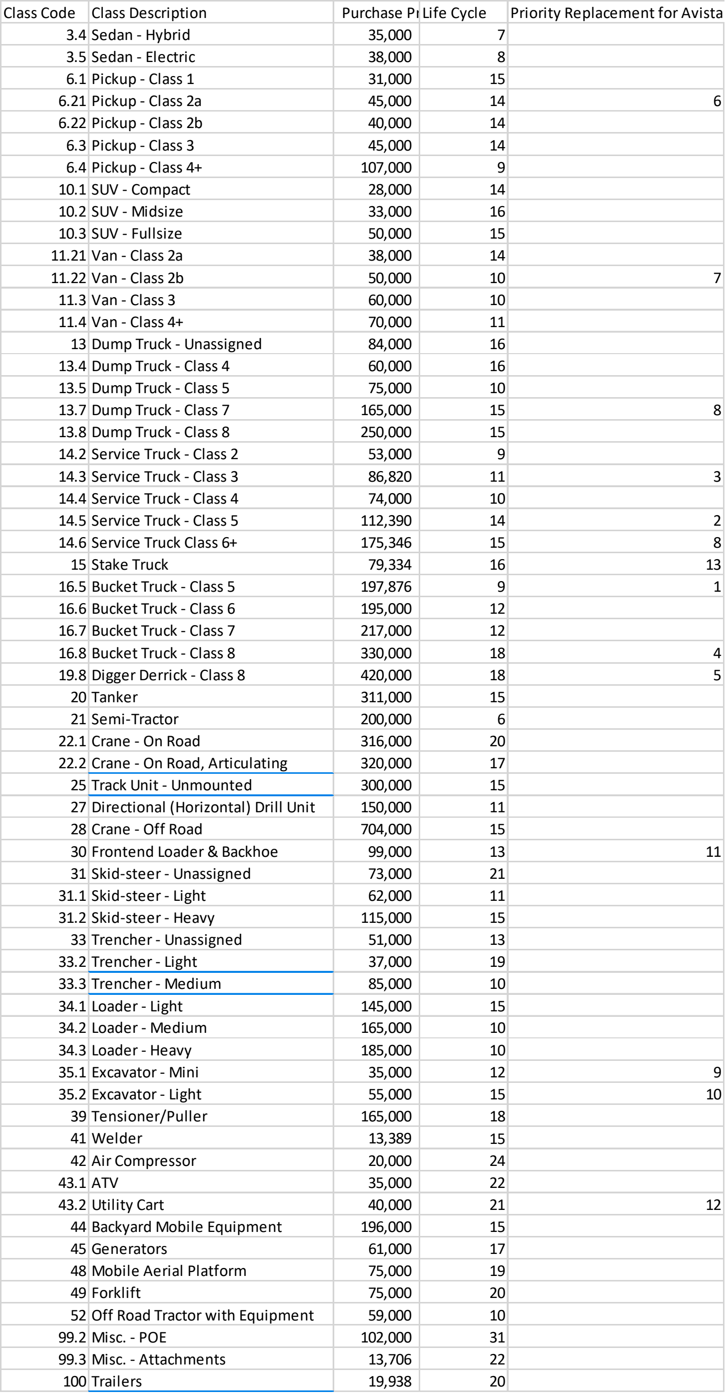
1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Supplemental information is available from Utilimarc.com

Fleet Equipment Capital Refresh Program

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.



Class Code	Class Description	Purchase P	Life Cycle	Priority Replacement for Avista
3.4	Sedan - Hybrid	35,000	7	
3.5	Sedan - Electric	38,000	8	
6.1	Pickup - Class 1	31,000	15	
6.21	Pickup - Class 2a	45,000	14	6
6.22	Pickup - Class 2b	40,000	14	
6.3	Pickup - Class 3	45,000	14	
6.4	Pickup - Class 4+	107,000	9	
10.1	SUV - Compact	28,000	14	
10.2	SUV - Midsize	33,000	16	
10.3	SUV - Fullsize	50,000	15	
11.21	Van - Class 2a	38,000	14	
11.22	Van - Class 2b	50,000	10	7
11.3	Van - Class 3	60,000	10	
11.4	Van - Class 4+	70,000	11	
13	Dump Truck - Unassigned	84,000	16	
13.4	Dump Truck - Class 4	60,000	16	
13.5	Dump Truck - Class 5	75,000	10	
13.7	Dump Truck - Class 7	165,000	15	8
13.8	Dump Truck - Class 8	250,000	15	
14.2	Service Truck - Class 2	53,000	9	
14.3	Service Truck - Class 3	86,820	11	3
14.4	Service Truck - Class 4	74,000	10	
14.5	Service Truck - Class 5	112,390	14	2
14.6	Service Truck Class 6+	175,346	15	8
15	Stake Truck	79,334	16	13
16.5	Bucket Truck - Class 5	197,876	9	1
16.6	Bucket Truck - Class 6	195,000	12	
16.7	Bucket Truck - Class 7	217,000	12	
16.8	Bucket Truck - Class 8	330,000	18	4
19.8	Digger Derrick - Class 8	420,000	18	5
20	Tanker	311,000	15	
21	Semi-Tractor	200,000	6	
22.1	Crane - On Road	316,000	20	
22.2	Crane - On Road, Articulating	320,000	17	
25	Track Unit - Unmounted	300,000	15	
27	Directional (Horizontal) Drill Unit	150,000	11	
28	Crane - Off Road	704,000	15	
30	Frontend Loader & Backhoe	99,000	13	11
31	Skid-steer - Unassigned	73,000	21	
31.1	Skid-steer - Light	62,000	11	
31.2	Skid-steer - Heavy	115,000	15	
33	Trencher - Unassigned	51,000	13	
33.2	Trencher - Light	37,000	19	
33.3	Trencher - Medium	85,000	10	
34.1	Loader - Light	145,000	15	
34.2	Loader - Medium	165,000	10	
34.3	Loader - Heavy	185,000	10	
35.1	Excavator - Mini	35,000	12	9
35.2	Excavator - Light	55,000	15	10
39	Tensioner/Puller	165,000	18	
41	Welder	13,389	15	
42	Air Compressor	20,000	24	
43.1	ATV	35,000	22	
43.2	Utility Cart	40,000	21	12
44	Backyard Mobile Equipment	196,000	15	
45	Generators	61,000	17	
48	Mobile Aerial Platform	75,000	19	
49	Forklift	75,000	20	
52	Off Road Tractor with Equipment	59,000	10	
99.2	Misc. - POE	102,000	31	
99.3	Misc. - Attachments	13,706	22	
100	Trailers	19,938	20	

The capital plan attached here includes updates from the 2020 benchmark analysis. Also included in the amount is 2021 orders that due to supply chain issues is pushed to 2022 for delivery and in-service. A majority 2022 plan has been executed due to 400-650 day lead times from multiple vendors. The 2022 plan will total $6.6mm.

Option	Capital Cost	Start	Complete
Fully funded (no adds to complement funded)	$33.3M	01.2022	12.2026
Partial funding	$19.5M	01 2022	12 2026
Lease	$0M	01 2022	12 2026

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Avistas Vehicle Replacement Model (VRM) uses fleet data to develop company specific replacement criteria for each vehicle class in fleet. This analysis is unique to the behavior and characteristics of the Avista fleet. The inputs for the Utilimarc VRM include:

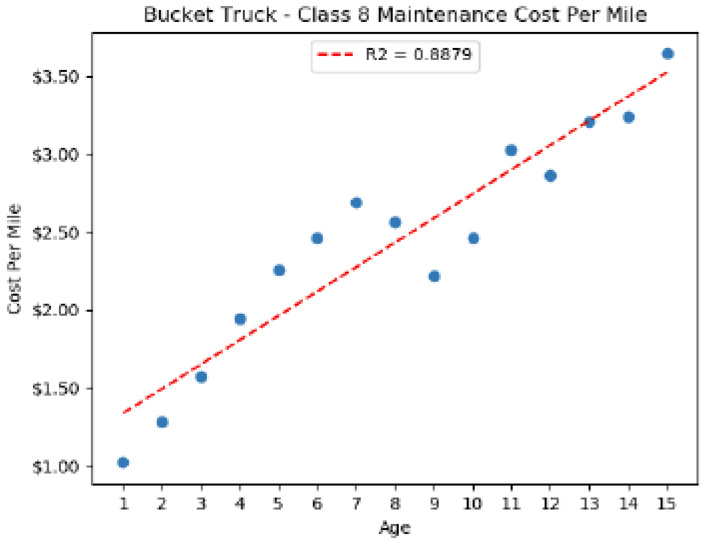
- Company specific trending parts and labor cost for each vehicle class
- Company specific purchase price for each vehicle class
- Company specific annual usage patterns (mileage) for each vehicle class
- Company specific loaded productive labor rate and mechanic productivity
- Vehicles are identified as candidates for replacement when over their recommended replacement age or replacement life to date mileage, whichever occurs first.

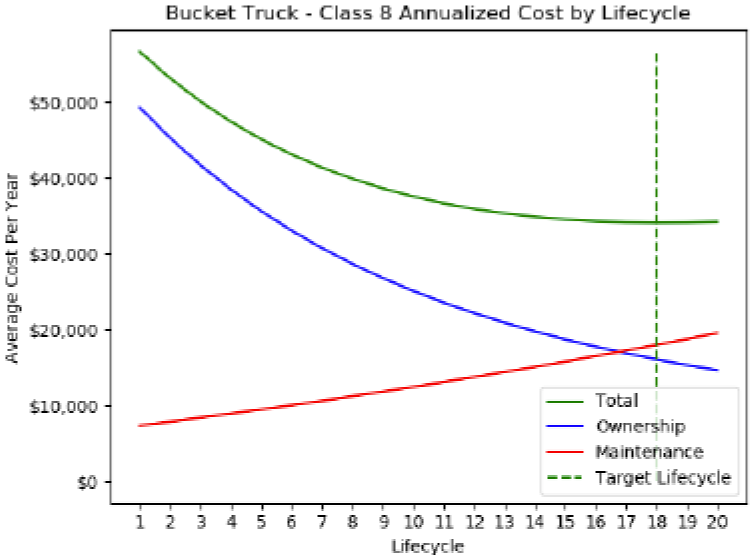
A vehicle is identified as a candidate for replacement when it reaches its replacement range for age or lifetime mileage. Replacing within these ranges ensures operating within 1% of the lowest total ownership cost of the vehicle over its lifetime. A standard regression model is used in this analysis.

Reference key points from external documentation, list any addendums, attachments etc.

Example

Bucket Truck - Class 8





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 capital in this case will be spent evenly over the 5 year period. The investment of capital in this case will provide a consistent replacement plan which enables a predictable parts and labor cost, vehicle downtime and technician requirements

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Avista's fleet of vehicles is used by nearly every department. By not investing in new assets we increase the potential for equipment failure and unforeseen downtime for our crews and employees in the field. Our industry is amid many changes driven by internal as well as external factors. By not having a replacement plan we limit ourselves on being able to keep up with current standards, as well as new safety requirement. The impact would most be felt when a large EOP or mutual aid event occurs.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

The first alternative is to invest approximately 25% less in capital that what our optimum scenario is. By investing at this level, we would be able to continue to address the highest cost per mile vehicle classes (five of which account for 55% of the total annual operating spend) and those vehicles that are critical response units. We will still face increasing costs, downtime and constrained technician hours but the amount is mitigated by the focus on those high cost classes. Additionally, we risk the potential that additional funding is apportioned in one or two of the out years to get “caught up.” This creates bubbles of work for the team purchasing vehicles but also in the parts and maintenance costs.

The second scenario would be to fund the program at 50% of what the recommended spend is from our data analytics. This route would create even larger bubbles that will need to be addressed by future capital spending that could exceed the recommended spend by as much as 50%. One of our biggest challenges we will face in this scenario would be the effect it has on our shop workload. As previously stated we this scenario will have a 12,000 hour or a 33% increase in the amount of labor available to what is required to repair all demand driven repairs and maintenance. With a predictable number of units coming in we can better plan our teams schedule. This also allows us to maintain a level staffing needs year over year.

The third scenario is leasing option. Multiple utility fleets lease their vehicles. This on the surface has the potential to free up capital for other uses. The risk in this option is that you are trading a capital cost for an operating cost. The depreciation that had been realized on the P&L statement is now an O&M cost that must be absorbed. Those costs include a leasing company’s return on equity. This would require huge change management with help from the operations management team, as our vehicles are highly customized to ensure they can do their work in the most efficient and expedient manner.

Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

The Fleet Vehicle Refresh is a capital plan. Each vehicle or piece of equipment purchased get a jurisdiction code specific project number and a FERC specific task code. We begin purchasing the next years equipment during the summer of the prior year. Right now, we are taking delivery of equipment that had purchase orders cut last August. Our most expensive mounted hydraulic equipment has a 350 to 450 day lead time. We transfer each individual unit to plant when in becomes used and useful, which is approximately 30 days after receipt and invoicing.

2.5 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program enables to Our People to serve Our Customers. When the power is out or gas is not flowing due to an unexpected incident our fleet of trucks gets the people and equipment to where it needs to be and then runs until the issue is resolved.

2.6 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

The following figure represents the totals of maintenance costs and work orders generated per year. As can be seen on the first and last line we maintain a steady cost and work load year over year. We benchmark and review our results on an annual basis.

Utilimarc Lifecycle Replacement Projections

Value	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual Capital	$5,556,379	$5,794,138	$6,765,327	$8,550,317	$8,038,595	$9,425,595	$9,470,600	$10,096,500	$9,378,313	$8,847,861
Units Replaced	69	71	76	88	86	89	90	91	82	85
Annual Maintenance	$8,057,038	$8,330,557	$8,531,107	$8,624,560	$8,757,253	$8,818,198	$8,916,771	$8,928,386	$9,015,413	$9,200,408
Annual Ownership	$5,333,819	$5,350,745	$5,506,508	$5,908,989	$6,174,116	$6,614,670	$6,989,863	$7,406,765	$7,650,302	$7,792,466
Total	$13,390,860	$13,681,300	$14,037,610	$14,533,550	$14,931,370	$15,432,870	$15,906,630	$16,335,150	$16,665,720	$16,992,870
Out of Life	227	223	251	265	251	234	264	243	253	250
Avg Age	11.63	11.45	11.34	11.10	10.93	10.72	10.51	10.29	10.18	10.03
Labor Hours	41,456	42,023	42,191	41,817	41,628	41,095	40,740	39,993	39,591	39,611

Half Utilimarc Lifecycle Replacement Projections

Value	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual Capital	$2,536,587	$2,816,819	$3,741,889	$3,859,175	$3,546,683	$3,981,964	$4,467,021	$4,556,362	$4,647,489	$4,740,439
Units Replaced	31	36	40	41	39	40	42	42	42	42
Annual Maintenance	$8,137,428	$8,602,623	$9,036,137	$9,483,095	$9,949,424	$10,410,080	$10,862,510	$11,319,940	$11,772,930	$12,223,390
Annual Ownership	$4,853,715	$4,496,113	$4,341,073	$4,230,449	$4,090,467	$4,043,929	$4,084,629	$4,135,452	$4,196,157	$4,264,716
Total	$12,991,140	$13,098,740	$13,377,210	$13,713,540	$14,039,890	$14,454,010	$14,947,140	$15,455,390	$15,969,090	$16,488,110
Out of Life	265	296	360	421	454	486	564	592	642	686
Avg Age	12.43	12.73	13.07	13.42	13.81	14.18	14.50	14.82	15.12	15.41
Labor Hours	41,870	43,395	44,689	45,979	47,295	48,514	49,630	50,706	51,701	52,626

Avista Budget Replacement Projections

Value	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual Capital	$5,180,552	$6,147,232	$6,143,363	$6,189,603	$6,176,617	$6,206,909	$6,212,876	$6,052,722	$6,171,291	$6,203,925
Units Replaced	59	72	72	61	61	54	57	52	50	51
Annual Maintenance	$7,907,314	$8,209,488	$8,555,177	$8,804,992	$9,117,942	$9,451,825	$9,770,447	$10,154,520	$10,537,160	$10,947,320
Annual Ownership	$5,252,313	$5,318,170	$5,381,230	$5,425,657	$5,480,650	$5,529,131	$5,572,587	$5,588,461	$5,622,189	$5,651,153
Total	$13,159,630	$13,527,660	$13,936,410	$14,230,650	$14,598,590	$14,980,960	$15,343,030	$15,742,980	$16,159,350	$16,598,470
Out of Life	237	232	264	305	316	334	397	415	457	498
Avg Age	12.01	11.78	11.74	11.92	12.07	12.34	12.57	12.84	13.13	13.43
Labor Hours	40,686	41,412	42,310	42,692	43,342	44,048	44,640	45,485	46,274	47,132

2.7 Supplemental Information

2.7.1 Identify customers and stakeholders that interface with the business case

Internal Customers:

Distribution Electric Ops	Generation	Engineering
Gas Distribution Ops	Gas Metering	Communication
Sub-station Support	Electric and Gas Metering	IT
Project Management	CPC	Relay Shop
MS Shop	Cathodic	Veg Management

Stakeholder include:

Plant Accounting	Rates
Engineering	Operators

2.7.2 Identify any related Business Cases

None at this time

3.1 Steering Committee or Advisory Group Information

The fleet capital plan is driven by statistical analysis that is based on our financial and operating outcomes. The analysis is reviewed by the Fleet Manager, Fleet Specialist and our Fleet Analyst.

3.2 Provide and discuss the governance processes and people that will provide oversight

Each individual vehicle purchase is approved in two parts: 1) The Fleet Manager approves the CPR request and then the director is notified. 2) The requisition process is approved based on value from the Fleet Manager all the way to the CEO if the value is great enough.

Department and district managers are involved in the order process by confirming which vehicles to be replaced and helping to ensure any requests that specific operators or crews may have. Managers, operators/drivers sign off on a VLC form which is maintained for every class and build of vehicle.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Annually, Fleet Spec Committees for our major operating groups come together to review the specifications of their specific core operating vehicles. This helps ensure that vehicles come from the manufacturer ready to work. We track our revisions/change orders on an ECO form and record the dollars in our tracking program by using a change order specific task code. Fleet’s goal is to not exceed more than 1% of our total budget in change orders. In 2019 we were less than .8% of our total spend for change orders.

Fleet Equipment Capital Refresh Program

The undersigned acknowledge they have reviewed the Fleet Equipment Capital Refresh 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: Gregorymloew Date: 7/2/21
Print Name: Gregory Loew
Title: Fleet Manager
Role: Business Case Owner

Signature: Alicia Gibbs Date: 7/2/2021
Print Name: Alicia Gibbs
Title: Director, Shared Services
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Gas Operator Qualification Compliance

EXECUTIVE SUMMARY

As an operator of gas infrastructure, Avista Utilities is required by regulation to minimize the impact of safety and integrity of the pipeline facilities due to human error that may result from an individual's lack of knowledge, skills, or abilities during the performance of certain activities, or covered tasks. Craft Training and Gas Operations are responsible for ensuring a qualified and competent workforce. This is partially accomplished by evaluating and qualifying internal and contract employees on Operator Qualification tasks specific to Avista's natural gas infrastructure.

This business case will provide the tooling, vehicles, and equipment necessary to enable internal Avista Evaluators to evaluate Avista "non-peer" employees and contract personnel under the PHMSA regulations for Operator Qualification. Further, the tooling, vehicles and equipment may be used by Avista's Evaluators to maintain proficiency in the tasks required by the program and to design, construct and implement new testing tools, techniques and technologies. Not providing these resources would result in the Evaluators being unable to perform their duties, possibly resulting in regulatory penalties and incidents that impact Avista's customers and the public. This project will support Avista's gas operations in Idaho, Washington and Oregon. The total cost of the recommended solution to support these activities is $185,000 over a 5-year period or $37,000 annually.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Joe Brown*	*Executive Summary Only*	*7/6/2020*	*Business Case 2020 Refresher*
1.0	*Joe Brown*	*Final version for 2020 capital update*	*7/29/2020*	*Full amount approved*
1.1	*Joe Brown*	*Reviewed for Approval*	*7/13/2021*	*No Changes Required*

GENERAL INFORMATION

Requested Spend Amount	$185,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	Craft Training and Operator Qualification [I02]
Business Case Owner | Sponsor	Joe Brown | Jeremy Gall
Sponsor Organization/Department	Human Resources
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

Gas Operator Qualification Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Growth and high attrition rates in the Natural Gas industry has led to a workforce shortage of trained and competent personnel. Employing this workforce has resulted in several safety and quality control issues on Avista's natural gas infrastructure.

Currently, Avista Utilities evaluates internal personnel by utilizing loaned employees from Gas Operations to evaluate other peer employees. The utilization of peer craft employees to conduct evaluations is not recognized as a best practice in the natural gas industry.

Further, Avista's Gas Contractors train and evaluate themselves on Avista's covered tasks. These activities are conducted independent of Avista's oversight. Evaluation of contract employees by contract employees, with no utility oversight, is not recognized as a best practice in the natural gas industry.

Recent safety and quality incidents in the field and questionable evaluation practices has demonstrated the need for direct evaluation by internal, "non-peer", Avista evaluators for Operator Qualification. This unbiased evaluation practice will determine the knowledge, skill and ability of personnel and ensure the integrity of qualifications.

The following regulations outline the requirements of Operator Qualification that must be met by Avista as an Operator of a natural gas utility. These requirements apply to both internal and contract employees.

1. Background. 49 C.F.R. §§ 192.803 through 192.809 prescribe the requirements associated with qualifications for gas pipeline company personnel to perform "covered tasks." 49 C.F.R. § 192.801 contains a definition of "covered task." In WAC 480-93-999, the commission adopts 49 C.F.R. §§ 192.801 through 192.809. However, in this section, the commission includes "new construction" in the definition of "covered task."
2. Accordingly, for the purpose of this chapter, the commission defines a covered task that will be subject to the requirements of 49 C.F.R. §§ 192.803 through 192.809 as an activity, identified by the gas pipeline company, that:
   a. Is performed on a gas pipeline;
   b. Is an operations, maintenance, or new construction task;
   c. Is performed as a requirement of Part 192 C.F.R.; and
   d. Affects the operation or integrity of the gas pipeline.
3. In all other respects, the requirements of 49 C.F.R. §§ 192.801 through 192.809 apply to this chapter.
4. The equipment and facilities used by a gas pipeline company for training and qualification of employees must be similar to the equipment and facilities on which the employee will perform the covered task.

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 primary business driver for this business case is *Mandatory & Compliance* and the secondary drive is *Customer Service Quality*. Avista must have and execute an OQ Program in order to maintain compliance with laws, rules and regulations. Secondarily, the safety and quality of Avista's gas delivery business is greatly impacted by the testing program carried out through the implementation of the OQ program.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Avista's OQ Program is in its implementation stage and must be funded. Deferring or canceling this funding altogether exposes the company to regulatory risk and possible fines.

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 implementation of this new evaluation process for the OQ Program began on June 1, 2020. Monitoring, metrics and reporting will be developed based on this implementation stage. Currently, Avista has more than 350 active contractors that go through testing and evaluation. Lagging safety and quality metrics may be used in the future to assess the success of this change in program execution.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

No studies have been conducted to date. This business case supports an industry "best practice" where non-peer employees with evaluate personnel on OQ tasks.

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.

NOT APPLICABLE

The proposed solution is to obtain the resources needed for OQ Program evaluation

This is the least cost alternative from a capital perspective when considering the risks associated with outsourcing the OQ evaluations to a third party, or fully funding all tools and equipment.

Option	Capital Cost	Start	Complete
1. OQ Evaluator Tools and Material – Partial	*$185,000*	*01 2021*	*12 2025*
2. OQ Evaluator Tools and Material – Full	*$460,000*	*01 2021*	*12 2025*
3. Outsource OQ Evaluator Program	*$0*	*01 2021*	*NA*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

For the recommended solution (Option 1) [OQ Evaluator Tools and Material – Partial], this amount is based on the estimate of tools and equipment that will need to be purchased and utilized annually in order to support the program. The tools and equipment in this solution will be shared among the Spokane and Oregon locations and there will not be significant duplicate. This will slightly increase O&M expense due to travel and sharing of equipment among evaluators.

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 is a compliance program and there are no O&M offsets associated with the project.

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 greatest impact of this business case is on Gas Operations and Avista's Gas Customer. Gas Operations contracted resources will be tested through this program which may result in safer, higher quality work products. Avista's Gas Customer may receive safer, better service in the areas where Avista utilizes contract personnel for gas work.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

For the recommended solution (Option 1) [OQ Evaluator Tools and Material – Partial], this amount is based on the estimate of tools and equipment that will need to be purchased and utilized annually in order to support the program. The tools and equipment in this solution will be shared among the Spokane and Oregon locations and there will not be significant duplicate. This will slightly increase O&M expense due to travel and sharing of equipment among evaluators.

For Option 2, it is estimated that Avista may need to spend $92,000 annually in order to purchase each evaluator their own tools and equipment utilized for skill evaluations. This would include upgrading existing equipment and replacing all outdated equipment. This includes many of the tools and materials utilized by contractors, such as leak survey and locating, that are extremely capital intensive. We believe the prudent decision is to share this equipment among the evaluation areas and reduce the overall capital spend.

Finally, for Option 3, OQ skill evaluations could be outsourced to a 3rd Party contract resource. This outsourced testing model has been adopted by some peer companies. This option is estimated to cost more than $600,000 in O&M alone, not to mention the risk this option would pose from an employee morale and labor relations perspective. Further, this option does not drive a culture of safety, compliance and quality that we hope to achieve by executing on Option 1.

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. spend, and transfers to plant by year.

Equipment and tools will be purchased on an annual basis and will become ‘used-and-useful’ during the year as the evaluators implement the resources in the field.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This investment aligns with two of Avista’s key Focus Areas of ‘Our Customers.’ and ‘Perform.’.

When it comes to Avista’s customers, this program promotes transparency in the safety, quality and integrity of Avista’s work product delivered to each customer. The safety and integrity of the gas system depends on a highly skilled workforce, and this program helps ensure these skills meet or exceed Avista’s standards. Regarding performance, this program helps ensure customers are served with safe and reliable infrastructure.

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

Avista must comply with laws, rules and regulations as well as provide customers with safe, reliable gas resources. This program helps ensure the safety and quality of Avista’s gas system. As stated previously, this program was implemented on June 1, 2020 and monitoring, metrics and reporting will be developed as part of the ongoing program as it is executed.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Key internal stakeholders include Craft Training, Gas Operations, and Compliance. Key external stakeholders include Avista's Customers and 3rd Party Contractors.

2.8.2 Identify any related Business Cases

NA

3.1 Steering Committee or Advisory Group Information

See the governance process below

3.2 Provide and discuss the governance processes and people that will provide oversight

As a practical matter, the OQ Evaluators [3] will plan their needs for tools, materials and equipment with the Manager or Craft Training &OQ. The team will prioritize their needs and manage the funds accordingly.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Manager or Craft Training & OQ will be responsible for prioritization, change requests, documentation and monitoring of this project.

Gas Operator Qualification Compliance

The undersigned acknowledge they have reviewed the *Gas Operator Qualification Compliance 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: Joe Brown Date: 7/13/2021
Print Name: Joe Brown
Title: Mgr Craft Training & OQ
Role: Business Case Owner

Signature: Date: 7/19/2021
Print Name: Jeremy Gall
Title: Sr. Mgr Safety & Craft Training
Role: Business Case Sponsor

Signature: NA Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Jackson Prairie Joint Project

EXECUTIVE SUMMARY

Avista co-owns a natural gas storage reservoir, Jackson Prairie Underground Natural Gas Storage Facility (JP). JP is essential to ensuring reliable, cost-effective natural gas service for consumers during the region's annual wintertime peaks in natural gas demand. Avista's 1/3 share of Jackson Prairie storage allows the utility to meet 100 percent of its customers' peak winter demand with the facility's stored reserves.

JP can hold about 44 billion cubic feet of natural gas, of which 25 billion cubic feet is working natural gas. This storage ensures that natural gas supplies are available during the year to meet customer demand in all three operating states; Washington, Idaho, and Oregon. In addition, this storage helps to stabilize customers' energy costs and soften the impacts of price volatility in the wholesale natural gas market. Avista buys and stores significant amounts of natural gas during the lower-priced months, and then taps the reserves, typically in winter months, when customers' natural gas requirements—and wholesale natural gas prices—are highest.

Avista has co-owned Jackson Prairie's facilities and natural gas storage rights equally with Seattle-based Puget Sound Energy (PSE) and Houstan, Texas-based Williams-Northwest Pipeline since 1962. Predecessor businesses of these three companies developed Jackson Prairie as a natural gas storage facility in the 1960s. PSE manages the Jackson Prairie operations.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Scott Kinney*	*Updated Business Case*	*07/12/2021*	

GENERAL INFORMATION

Requested Spend Amount	$11,990,000 *(Avista's 1/3 cost obligation)*
Requested Spend Time Period	*5 Years*
Requesting Organization/Department	Natural Gas Energy Resources
Business Case Owner | Sponsor	Scott Kinney | Jason Thackston
Sponsor Organization/Department	Energy Resources
Phase	Execution
Category	Project
Driver	Performance & Capacity

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

This request is for the ongoing funding for the capital costs associated with the JP operations.

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 drivers for funding JP are Perfromance and Capacity. JP provides solutions for the following gas supply needs:

- Stored gas supply that enables Avista to reliably serve customers during peak load demand.
- Risk mitigation for shielding customers from extreme daily gas price volatility during cold weather or other events affecting the natural gas commodity market.
- A mechanism for purchasing gas at lower prices during off-peak periods for use during high cost periods.

All commodity price benefits resulting from the utilization of JP are passed along to the customer through the annual PGA filings.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

JP is a functioning storage project that has critical ongoing capital funding requirements for ensuring continuous safe and reliable operation of the plant. Not funding JP at the requested levels increases a number of risks for plant operations including, but not limited to, non-compliance for underground storage safety mandates, deliverability during peak demand periods, reduced physical plant security, reduced efficiency of plant output, or increased likelihood of component failure resulting in unplanned outages.

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 storage project is continually managed and monitored for optimal storage volume, injection and withdrawal performance, and other key operational metrics. An operations report is submitted to the JP Management Committee on a monthly basis. Additionally, the report provides a current and projected budget status.

Jackson Prairie Joint Project

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

Option	Capital Cost	Start	Complete
Ongoing annual funding for JP capital budget	*2,379,000*	*01 2022*	*12 2022*
	2,370,000	*01 2023*	*12 2023*
	2,421,000	*01 2024*	*12 2024*
	2,410,000	*01 2025*	*12 2025*
	2,410,000	*01 2026*	*12 2026*
5 Year Total	*$11,990,000*	*01 2022*	*12 2026*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The budget is prepared by the plant operations team and is informed by a number of supporting documents, including:

- Engineering studies and ongoing operational monitoring data
- Risk gap analyses and risk mitigation plan
- Actual operational performance results
- Safety compliance and other regulatory mandates and requirements
- Contractual obligations
- Asset maintenance and replacement schedules

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 capital dollars will be spent throughout the year according the capital budget scheduling plan prepared by the JP operations team. An updated budget status is submitted monthly to track the spending. No O&M reductions are estimated as a result of this investment.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

JP is 1/3 owned but not operated by Avista. No impacts to other Avista business functions or processes are anticipated by this business case.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

No cost effective alternatives exist for replacing JP. Because JP is a unique solution that provides benefits/solutions for an array of supply needs, it would likely require multiple business solutions to replace the resource functionality provided by JP, none of which could fully duplicate the benefits of JP nor be cost competitive with JP.

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. spend, and transfers to plant by year.

The annual capital spending for JP includes multiple capital improvement investments, which become used and useful at the end of each budget year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

JP is a critical integrated supply resource for our natural gas business. JP helps enable the delivery of natural gas energy safely, responsibly, and affordably to 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

The requested capital budget amount is prudent and has been reviewed and approved by the JP Management Committee (described below). The capital budget amount will provide for and ensure the continuous operational performance contractually mandated by the JP owners, and licensed by FERC.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders who directly interface with the business case include the two other ownership partners; PSE and Williams-NWP. Additionally, the Pacific Northwest (PNW) natural gas market and pipeline operation are directly affected by JP. JP provides critical supply delivery funcationality to the PNW pipeline grid, especially during peak demand times.

2.8.2 Identify any related Business Cases

This replaces the 2020 JP Business Case.

3.1 Steering Committee or Advisory Group Information

A JP Management Committee meets quarterly to review and approve the capital budget status for the current year as well as to review and approve any ongoing or future expenses. A business representative from each of the 3 ownership partners has final authority on the Committee. The decisions are documented in the minutes of the meeting. Occasionally, a decision is made through email correspondence and is retained by the JP general manager. A monthly report is provided to the owners that includes the budget statue.

Avista's Risk Management Committee (RMC) oversees corporate decisions that affect joint energy resource projects including the Jackson Prairie Storage Project.

3.2 How will decision-making, prioritization, and change requests be documented and monitored

See answer to 3.1

The undersigned acknowledge they have reviewed the Jackson Prairie Storage Project 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: Scott Kinney Date: 7/12/21
Print Name: Scott Kinney
Title: Director Energy Supply
Role: Business Case Owner

Signature: /s/Jason Thackston Date: 7/13/21
Print Name: Jason Thackston
Title: SVP, Energy Resources
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Clean Energy Fund 3 – Eco-District G2G

1 GENERAL INFORMATION

Requested Spend Amount	$ 4,500,000 (Avista Contribution)
Requesting Organization/Department	Research and Development/ Distribution Operations
Business Case Owner	John Gibson (Project Sponsor)
Business Case Sponsor	Heather Rosentrater (Executive Sponsor)
Sponsor Organization/Department	Distribution Operations
Category	Strategic
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

- Heather Rosentrater (Executive Sponsor)
- John Gibson (Project Sponsor)
- Curt Kirkeby (Concept Engineer/Project Sponsor)
- To-be-determined (Project Manager)
- To-be-determined (Project Engineer)
- Washington State, Department of Commerce advisory group

2 BUSINESS PROBLEM

This Eco-District Grid Modernization project proposal ("EGM Proposal") will seek to leverage Avista's participation in the Eco-District by utilizing the net-zero, carbon free Catalyst building being constructed in the Eco-District to evaluate how these types of net-zero, carbon free developments impact the energy production and delivery system. Avista will deploy advanced thermal and electric storage assets integrated with load control and inverter technology with an overall objective to develop a control strategy within the Eco-District which balances the competing certification requirements of net-zero, carbon free developments against grid utilization strategies to reduce unnecessary investment in grid infrastructure. This project is branded the Grid To Green ("G2G") Project. The G2G Project assets and analytics will be designed to measure and value how net-zero, and carbon free developments impact the regional and local electrical system production and delivery system. The G2G Project objectives are: (1) to deploy electric and thermal storage assets in the Eco-District to modulate the voltage swings resulting from local intermittent generation; (2) to deploy electric, thermal storage assets with load management control strategies to reduce production, transmission and feeder peak demands; (3) to evaluate the transmission and distribution deferral that may be created through the deployment of the Eco-District combined with control and storage assets; and (4) to develop a social and economic outreach program to incentivize local small business adjacent to the Eco-District to deploy demand response programs.

Business Model Challenge

Avista's core business is centered on providing safe, reliable, efficient and low cost energy to our customers. However, consumers are increasingly asking for value-add energy products and services like self-generation, clean energy and socially responsible buildings.

Electric and Thermal Storage Integration Challenger

Within the last ten years, significant technology advancements have occurred in building mechanical systems to heat and chill building environments. Many of these advancements have evolved around various thermal dynamic processes to store, extract and recycle hot and chilled water. However, these mechanical system advances have been driven to support just the building conditioned environment.

Electrical Transactive Bus

Consumers want to participate in their local economy, which is evident just from the simple concept of local farmers markets. In the energy environment, energy prosumers are wanting to participate in local energy exchanges with renewable. So, what is the local exchange? And how would transactions occur and be valued?

Operational Challenge: Open Source Energy Operating System

Today, the interconnection requirements to deploy controllable Distributed Energy Resources ("DERs") on the grid requires significant engineering resources in order to perform interconnection studies, establish design specifications and deploy control and protection settings. How could we develop a grid platform which would support a "plug and play" type capability to allow for a seamless interconnection of DERs?

DC Bus

The delivery of electrical energy across long distances is more efficiently accomplished with Alternating Current ("AC") power. Current estimates show approximate energy loss in the twenty to thirty percent due to the conversion between AC to Direct Current ("DC"). Would it be practical to centralize DC generation resources like solar and storage in order to reduce these losses? Could a DC system or bus be leveraged by a buildings' participation in the Eco-District in order to address building code requirements for backup generation or lighting?

Extending Benefits to Local Community

The Eco-District development is being built in the East Sprague area of Spokane that has traditionally been economically disadvantaged, and small businesses currently struggle with their bottom line.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Implementation of CEF3 Proposal	$4,500,000[1]	6/2019	12/2022

Project Opportunities for Solution Development

This EGM Proposal contains key components of innovation around the utility business model, grid and control assets, technology platforms and outreach learning programs. For each innovative component, the challenge, opportunities and solution is summarized.

Changes to the Business Model

Net-zero and carbon free developments are expensive and difficult to finance using the traditional capital funding model. The HUB building will centralize electrical, thermal and mechanical assets in order to improve the economic viability of these net-zero, carbon free developments

Integration of Electric and Thermal Storage

Centralizing the electrical, thermal and mechanical components in the HUB provides adequate scale to evaluate the relative impact of these systems on the grid.

Creation of an Electrical Transactive Bus

The HUB and its 480 V bus offers potential to facilitate a local market hub (balancing area) for local exchanges. This 480 V bus in the HUB is common point of coupling of the Eco-District's load and renewable and storage resources.

Operation Through an Open Source Energy Operating System

Avista and a coalition of like-minded utilities are investing in an effort to develop an open source platform that can enable an interoperable framework to interconnect resources to the electric distribution system (branded as "openDSP")The first release of openDSP is currently scheduled for the 3rd quarter of 2019. This platform will enable a variety of grid services similar to that envisioned by the Eco-District G2G Project.

Centering Around a DC Bus

The HUB is being designed with a DC system to tie the Catalyst and HUB solar assets to a common inverter in the HUB which ties to the 480 V AC bus.

Extending Benefits to Local Community

The East Sprague business area receives energy and capacity from the same distribution station and feeders which serve the Eco-District. Could small businesses and the community benefit from the optimization of these feeders? Would the community be able to participate in the renewable energy ecosystem somehow by offsetting demand or through other efficiencies?

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[1] With a total capital project cost of $7 million, $2.5 million has been appropriated and approved by the Washington State Department of Commerce and will be provided to Avista upon meeting defined Milestones and $4.5 million is being requested of Avista

Strategic Innovation

Innovative Component #1: Business Model

The HUB will deploy a 480 V bus and switchgear which will pass through electric service to the building owners participating in the Eco-District. For the first time, private investment will be made in utility infrastructure, which would have historically been made by the utility. Also, the Eco-District distributed generation resources ("DERs") will be inter-tied to a 480 V bus which serves the Eco-District load. Ultimately, the HUB's 480 V bus will enable the Eco-District to serve its own load with its generation, creating a unique and new type of business model.

Innovative Component #2: Electric and Thermal Storage

The HUB's centralized thermal storage, boiler and chillers will be combined with electric storage and controller technology to co-optimize value between building efficiency and grid utilization.

Innovative Component #3: Electrical Transactive Bus

Under the G2G Project, PNNL and WSU will develop a combination of market and control strategies to simulate transactions that could occur across the HUB 480 V bus for building tenants. The research goals are to establish the technical and economical capability to deploy a transactive market in the HUB.

Innovative Component #4: Open Source Energy Operating System

The G2G Project control technology will be designed and deployed to adhere to the openDSP platform interoperability specification. This specification requirement will allow the G2G Project deployments to be scalable across the country.

Innovative Component #5: DC Bus

The G2G Project will tie the electric storage assets to the DC bus as a part of its deployment. The control technology will manage assets on the DC bus to optimize values between building and grid services. Metrics will be put in place to determine if the energy savings occur by centralizing the conversion between AC and DC.

Innovative Component #6: Extending Benefits to Local Community

As a part of the G2G Project, PECI will create outreach programs to the local business to gage interest in programs that could reduce capacity requirements on the local feeders. PECI will leverage Urbanova's software platform to advertise options for system reduction programs which would direct specific savings to a neighborhood urban renewal district.

Clean Energy Fund 3 – Eco-District G2G

Proposed Project Schedule

Scope Development and Partner Coordination	6/2019 through 6/2020
Asset Procurement	9/2019 through 6/2020
Detailed Engineering Design	6/2020 through 3/2021
Equipment Delivery, Installation and Construction	3/2021 through 6/2021
Systems Integration and Commissioning	6/2021 through 8/2021
Analytics and Reporting	8/2021 through 6/2022

Impacts to Future O&M/Stakeholder Involvement

- Spokane Area Engineering/Distribution Engineering

  Initial project design, implementation and construction; no ongoing O&M in addition to the programs in place (project and electrical design)
- Distribution Dispatch

  Project implementation, commissioning and ongoing operation; no ongoing O&M in addition to the staff in place (operation will be assigned to existing staff)
- Asset Maintenance

  Ongoing battery maintenance will be addressed through an O&M Agreement with each supplier, and is expected to be less than $100,000 per year

Budget Development

The proposed budget for the project was created and vetted thought the State of Washington Clean Energy Fund oversight committee, with significant input from the CEF1 (Turner Energy Storage Project) and CEF2 (Micro-Transactive Grid) budget and actual costs. This allowed the Grant Application to include a budget and request developed with a fair amount of confidence.

Expected Spend Schedule

Calendar Year 2019	$ 500,000
Calendar Year 2020	$ 3,000,000
Calendar Year 2021	$ 1,000,000

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Clean Energy Fund 3 – Eco-District G2G 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: Date: 6/26/2019
Print Name: John Gibson
Title: Chief Engineer, R & D
Role: Business Case Owner

Signature: Date: 6/27/19
Print Name: Heather Rosentrater
Title: VP, Energy Delivery
Role: Business Case Sponsor

Signature: Date: 7/30/19
Print Name: Mark Thies
Title: SVP + CFO
Role: Finance CPG

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Kenneth Dillon	5/29/2019	John Gibson	6/05/2019	Initial version
2.0	Kenneth Dillon	6/26/2019	John Gibson	6/26/2019	Included JW revisions

Template Version: 03/07/2017

ER 7001/ 7003 Structures and Improvements

EXECUTIVE SUMMARY

This program is be responsible for the capital maintenance, site improvement, and furniture budgets at over 40 Avista offices, storage buildings, and service centers (over 900,000 total square feet) Companywide. This program is intended to systematically address: lifecycle asset replacements (examples: roofing, asphalt, electrical, plumbing), lifecycle furniture replacements and new furniture additions (to support growth) and business additions or site improvements.

Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software (Terracon), 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements. There is currently a $7M Asset Condition backlog identified using Paragon Asset Condition software. A funding of $3.5M will allow us to maintain a flat backlog over the next 5 years.

This program supports Avista's entire Service Territory and all service codes and jurisdictions. Performing adequate Asset Management allows the Company to preserve and fully utilize their properties while reducing expensive repairs in the long term. It also ensures a safe environment for people and equipment. Damaged or poorly maintained facilities can create very real safety risks and associated liability for employees, customers, and contractors.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Lindsay Miller	Initial Version	07/10/2018	Initial Version
2.0	Lindsay Miller	Executive Summary Only	07/07/2020	Revised Template

ER 7001/ 7003 Structures and Improvements

GENERAL INFORMATION

Requested Spend Amount	$3,500,000
Requested Spend Time Period	Yearly
Requesting Organization/Department	Facilities
Business Case Owner | Sponsor	Eric Bowles | Dan Johnson
Sponsor Organization/Department	Shared Services
Phase	Planning
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Many of the service centers in Avista's territory were built in the 1950s and 60s and are starting to show signs of severe aging. Almost half of Avista's Assets were built before 1980. Most of our building systems are also past their recommended life based on recognized industry standards defined by Building Owners and Managers Association (BOMA), and International Facility Management Association (IFMA) and are requiring renovation or replacement. Many of the original campus layouts and buildings at our Service centers are no longer optimal today due to changes in our vehicle sizes, materials storage, and operations flow. These changes have required the need for project funding to address changing business and site requirements as well.

Location	Date Built	Address	City	State
Airport Hangar	2019	7500 W. Park Dr., Bldg 1060	Spokane	WA
Beacon (battery building and canopy)	2015	2180 N Havana St	Spokane Valley	WA
Clark Fork Bunkhouse	1959	806 Main St.	Clark Fork	ID
Clarkston Service Center	1975	1300 Fair Street	Clarkston	WA
Coeur d'Alene Service Center	1994	1735 N. 15th Street	Coeur d'Alene	ID
Colfax Facility	1990	704 North Clay	Colfax	WA
Colville Service Center	2010	176 Degrief Road	Colville	WA
Davenport Pole Yard and Vehicle Storage	1996		Davenport	WA
Davenport Service Center	1966	327 Morgan Street	Davenport	WA
Deer Park Service Center	2018	Airport Drive	Deer Park	WA

ER 7001/ 7003 Structures and Improvements

Dollar Road Fleet Shop	2015	2,406 N. Dollar Road	Spokane	WA
Dollar Road Service Center	2019	2406 N. Dollar Road	Spokane	WA
Dollar Road Truck Storage	2014	2406 N. Dollar Road	Spokane	Wa
Dollar Road Wash Bay	2018	2406 N. Dollar Road	Spokane	Wa
Downtown Network Center	2016	1717 W. 4th Ave	Spokane	WA
Downtown Project Center	2016	1717 W. 4th Ave	Spokane	WA
Elk City Facility	2017	Hwy 14	Elk City	ID
Goldendale	2015	912 E. Broadway	Goldendale	WA
Grangeville Facility	1933	201 E. Main Street	Grangeville	ID
Grangeville Pole Yard	2016		Grangeville	ID
Grants Pass Service Center	1960	618 SE J Street	Grants Pass	OR
Jack Stewart North Line Trailer	1985	8308 N. Regal	Spokane	WA
Jack Stewart Office Modular	2012	8307 N. Regal	Spokane	WA
Jack Stewart South Line Trailer	1993	8309 N. Regal	Spokane	WA
Jack Stewart Training Center	1999	8307 N. Regal	Spokane	WA
Kamiah Facility	1992	No Kidd Rd.	Kamiah	ID
Kellogg Covered Vehicle Storage	2012	121 Hill Street	Kellogg	ID
Kellogg Materials Storage	1980	122 Hill Street	Kellogg	ID
Kellogg Service Center	1960	120 Hill Street	Kellogg	ID
Kettle Falls Generating Plant Offices	1976	1151 Hwy 395 N	Kettle Falls	WA
Klamath Falls Service Center	2008	2825 Dakota Ct.	Klamath Falls	OR
Klamath Falls Storage Building	2012	2826 Dakota Ct.	Klamath Falls	OR
LaGrande Service Center	1994	10201 F Street	LaGrande	OR
Lewiston Call Center	1976	803 Main Street	Lewiston	ID
Main Campus Café/Auditorium	1959	1412 E. Mission Ave.	Spokane	WA
Main Campus Canopy 5	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Central Operating Facility	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Investment Recovery	2011	1411 E. Mission Ave.	Spokane	WA
Main Campus Mini Line Dock	1970	1411 E. Mission Ave.	Spokane	WA
Main Campus New Fleet Building	2017	1411 E. Mission Ave.	Spokane	WA
Main Campus Oil Storage Vault	1996	1412 E. Mission Ave.	Spokane	WA

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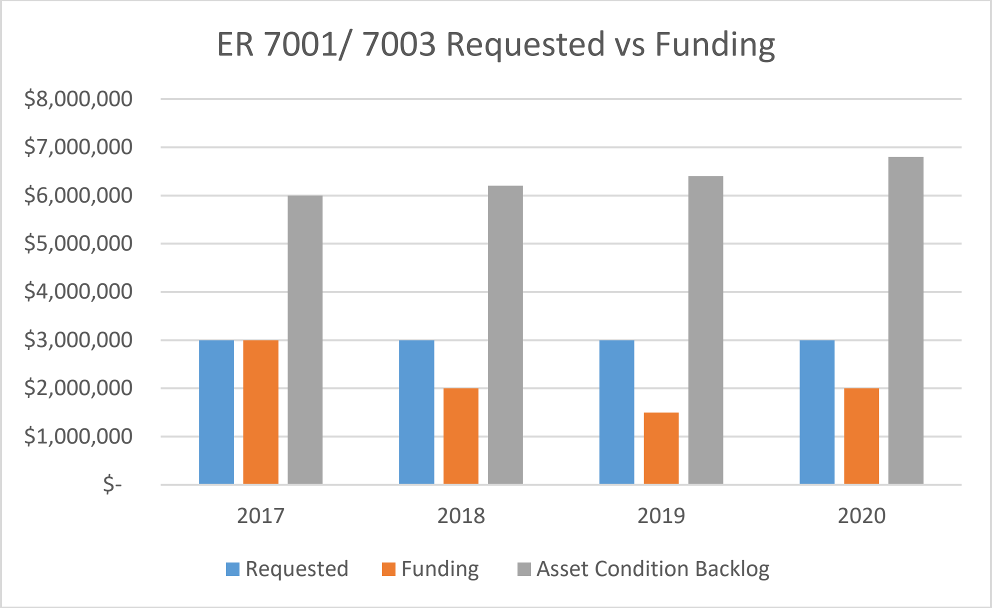
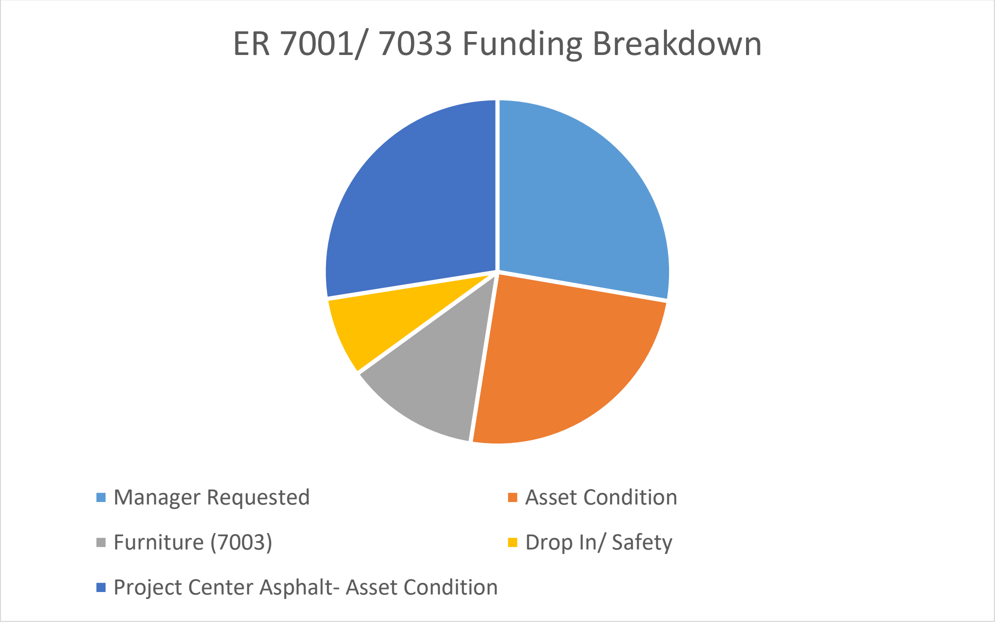
Main Campus Parking Garage	2019	1411 E. Mission Ave.	Spokane	WA
Main Campus Ross Park Building	1903	1411 E. Mission Ave.	Spokane	WA
Main Campus Service Building	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Warehouse Building	1959	1411 E. Mission Ave.	Spokane	WA
Main Campus Waste and Asset Recovery	2014	1411 E. Mission Ave.	Spokane	WA
Medford Outdoor Storage Canopy	1994	581 Business Park Drive	Medford	OR
Medford Service Center	1994	580 Business Park Drive	Medford	OR
Noxon Bunkhouse	1959	33 Avista Power Road	Noxon	MT
Orofino Service Center	1970	1051 Michigan Ave	Orofino	ID
Othello Service Center	1974	36 South 4th Avenue	Othello	WA
Pierce Facility	1985	104 Moscrip Dr.	Pierce	ID
Post Street Mobius / Annex Parking	1903	337 N. Post Street	Spokane	WA
Pullman Mechanic Shop	2012	5704 SR 270	Pullman	WA
Pullman Service Center	1959	5702 SR 270	Pullman	WA
Pullman Shed	1959	5704 SR 270	Pullman	WA
Pullman Storage Canopies	1959	5703 SR 270	Pullman	WA
Ritzville Facility	1955	401 E First	Ritzville	WA
Roseburg Service Center	2004	1404 Green Siding Road	Roseburg	OR
Sandpoint Covered Storage	1985	103 N. Lincoln	Sandpoint	ID
Sandpoint Service Center	1957	100 N. Lincoln	Sandpoint	ID
Sandpoint Storage Bays	1957	101 N. Lincoln	Sandpoint	ID
Sandpoint Truck Canopy	1985	102 N. Lincoln	Sandpoint	ID
Spokane Valley Call Center	1979	14523 E. Trent Ave.	Spokane Valley	WA
St Maries Offsite Garage and Pole Yard	2011		St. Maries	ID
St. Maries Service Center	1974	528 College Avenue	St. Maries	ID
Tekoa Facility	1971	West 101 Main Street	Tekoa	WA

ER 7001/ 7003 Structures and Improvements



Funding backlog

There is currently an identified backlog of $6.8M in Asset Condition work needed across the system of assets Facilities manages. In 2017 Terricon identified $6M in work on their initial assessment. This list is growing every year as our buildings age and new items are identified that need replacement. At the current funding level this backlog of capital work will continue to grow. The backlog is growing faster than our current funding model can accommodate.



ER 7001/ 7003 Structures and Improvements

Capital Lifecycle Asset Replacements ER 7001

This portion of the Structures and Improvements Program is based on the results of the Facilities Condition Assessment Survey. This survey will take into account the condition and lifecycle of each Facilities asset. Assets will be graded and those requiring replacement within the next 10 years will be estimated and scheduled for replacement at an appropriate year during the 10 year time frame of the survey. Buildings as a whole will be assigned a Facilities Condition Index (FCI) as part of the survey to help compare future capital needs and drive the decision of continued capital expenditures vs. possible replacement.

Examples (asphalt and structural issues):

Furniture Replacement or Additions ER 7003

This portion of the program is for furniture replacements based on industry standard lifecycles, condition, and availability of parts. The program is also meant to support new furniture additions required on approved building projects.

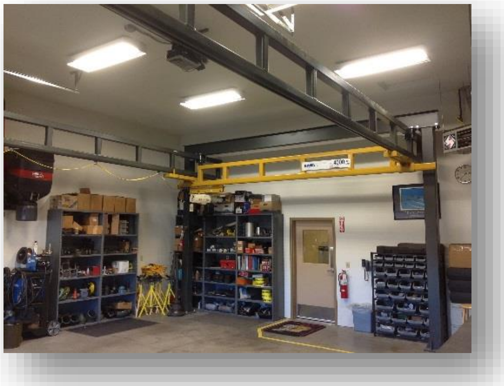
ER 7001/ 7003 Structures and Improvements

Examples:

Business Additions or Site Improvements ER 7001

This portion of the program is intended to support site improvement requests and productivity or business-related needs. Project requests are made by Operations site managers in June the year before. The list is then vetted for validity and business need by director-level management. Approved projects are then prioritized vs. capital asset replacement priorities, and assigned per available capital funding. Projects that are tied to compliance, safety, or productivity will be given funding preference.

Example (security fencing and gate, weld shop crane):



A robust operations and maintenance program will be required to help further extend the lifecycle of our Facilities assets and help to lessen capital replacement needs. Conversely, limited O&M maintenance programs will result in shorter than standard asset lifecycles, and ultimately increased Capital spending.

As the condition of our Facilities improve, capital asset replacements should lessen in future years of the program. This is again dependent on sufficient O&M maintenance budgets and workforce.

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 major driver of this business case is Asset Condition. Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software (Terracon), 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements.

Customers benefit from this project by Facilities providing a safe, usable buildings through which our Operations teams provide electricity and gas to our customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

As previously stated there is an identified backlog of Asset Condition work of $6.8M. This list is growing every year as our buildings age and new items are identified that need replacement. Deferring this work will cause a large bowel wave of Capital investment in future years. Providing a level investment over the next 10 years will allow us to prevent equipment failures and the need for a large one time capital investment.

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.

At this time, the only measure that can be used is to design solutions that provides room for growth, expands technology requirements, and adheres to safety and security best practices. Some of these solutions would include items such as:

1) Materials/ Storage: Provide spaces that meet the needs of the Stores team and Operations
2) Environmental/ Compliance: Ensure that the building and site meets with Avistas environmental standards
3) Employee/ Customer Impacts: Room for employee or operations growth
4) Operational Efficiency: Ensure that operational needs of employees are being met
5) Asset Condition: Provide systems and materials that meet with Avista standards

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The Asset Condition Study and Asset Condition Report for all of Avista's Assets is used to help determine the best options to resolve the various Asset Condition needs.

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 Asset Condition Study and Asset Condition Report for all of Avista's Assets is used to help determine the best projects to fund in any given year. Projects are prioritized by the Paragon Asset Condition program using metrics such as risk, impact and ROI. This prioritized list is then used to create the Asset Condition project list for the coming year.

Recommended Solution – Fund Program at full amount

This will allow us to address capital asset replacements and business needs. Safety, compliance, and productivity requests are rated highest and given priority first. Many of these replacements can create safety risk if not addressed (sidewalks, structural repairs). Not systematically addressing maintenance needs could ultimately result in complete replacement of the buildings at some point.

Option	Capital Cost	Start	Complete
Fund Program at Full Amount	$3.5M	01 2021	12 2021
Alternative #1- Partially Fund Program	Less than $3.5M	01 2021	12 2021
Alternative #2- Do Nothing	$0	-	-

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

There is currently an identified backlog of $6.8M in Asset Condition work needed across the system of assets Facilities manages. In 2017 Terricon identified $6M in work on their initial assessment. This list is growing every year as our buildings age and new items are identified that need replacement. At the current funding level this backlog of capital work will continue to grow. The backlog is growing faster than our current funding model can accommodate. It is the goal of this program to maintain a level backlog that projects are selected from using Terracon's risk assessment and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent.

Even funding this program at the $3M level we will never be able to completely reduce the backlog. Providing more than the $3M requested would require additional Project Management personnel and possibly FTE's. Facilities can accommodate this request within their current staffing model. It is the goal of this program to maintain a level backlog that projects are selected from using Terracon's risk and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent.

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.**

Average funding splits based on project priorities

This program is be responsible for the capital maintenance, site improvement, and furniture budgets at over 40 Avista offices, storage buildings, and service centers (over 900,000 total square feet) Companywide. This program is intended to systematically address the following needs:

- Lifecycle asset replacements (examples: roofing, asphalt, electrical, plumbing)
- Lifecycle furniture replacements and new furniture additions (to support growth)
- Business additions or site improvements (examples: adding a welding bay, vehicle storage canopy, expanding an asphalt yard. Can sometimes include property purchases to support site expansions.)

This program would encompass capital projects in all construction disciplines (roofing, asphalt, electrical, plumbing, HVAC, landscaping, expansions, remodels, energy efficiency projects). Facilities apportions approximately 50% to Asset Condition work that is identified using Paragon Asset Condition software (Terracon), 30% is set aside for Manager Requested projects, and 20% is kept aside for unexpected capital needs and furniture replacements.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

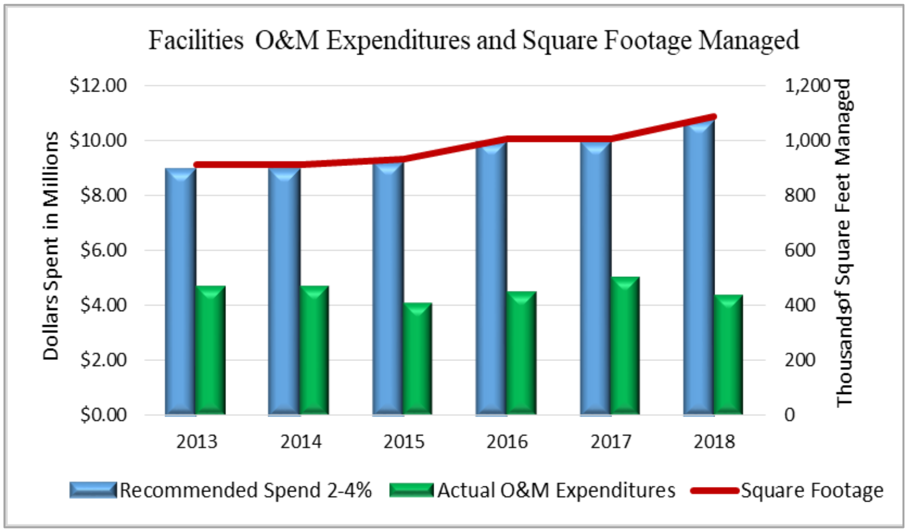
This Business Case will impact the employees that work out of the offices and locations where projects are completed. Other teams that may be impacted are: ET, ET Security, Radio Relay, Environmental and Stores/ Warehouse.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

<u>Alternative #1 – Partially Fund Program based on priority</u>

ER 7001/ 7003 Structures and Improvements

This option would decrease the capital program and increase existing O&M budgets to prolong structures' lifecycles beyond rated life, and reduce capital needs. This option is not the preferred approach over the long-term. Capital investments can be limited with a corresponding increase in O&M dollars. As building systems continue to decline O&M burden will increase.



The estimated replacement value of Avista's assets when the Terricon survey was taken in 2017 was approximately $242 million, with estimated maintenance and replacement requirements based on the Terracon report of $8,800,640 *per year*, which equals 3.64% of the current replacement value of the assets. The graph above clearly demonstrates that the amount spent by Avista (the green bars) typically does not reach the minimum level of O&M expenditures (the blue bars) standard in the building industry for basic sustenance of facilities. This level of underfunding would need to be addressed if the choice is made to underfund this program.

Business site improvement requests are intended to address changing business needs. These projects are usually linked to an enhanced productivity outcome. Having the ability to incorporate structures and equipment that fall within the improvement and business needs category can help support improved processes and lead to enhanced safety and longer lifecycles. When the budget needs to be reduced, reductions are first made to requests in this category.

Replacement is intended to replace aging units to achieve more predictable capital requirements and avoid replacement peaks caused by large-scale failures. Cutting into these requests over an extended period could lead to reduced efficiency and have safety impacts.

Alternative #2 – Do nothing

This option is not recommended. Building improvements are capital events that materially extend the useful life of a building and/or increase the value of a building. Building improvements are capitalized and recorded as an addition of value to the existing building. Sites will continue to decline due to normal wear and tear. The failure of certain systems, such as roofing or HVAC, can cause major damage to other areas of the building. Walkways and structural issues not being addressed could have safety impacts to employees, visitors and customers.

When failures occur the capital investment must be made, regardless of funding. This program provides an avenue to PLAN these capital investments.

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. spend, and transfers to plant by year.

The majority of projects in the Facilities Structures and Improvements program begin work in the 2nd or 3rd quarter of each year, and will usually transfer to plant before the end of the year. Some of the larger projects, or projects with extensive design, can carry over to the following year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The major reason to perform this project is to align with Avista's strategic vision of customer performance and reliability. Being able to provide service to our customers safely and efficiently is a cornerstone of Avista and the current Pullman Operations office does not allow employees to meet those goals.

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

Hopefully the business problems described earlier makes a strong case that this investment makes sense, as to avoid significant operational, reliability, and performance risks. As the project progresses, the scope and budget will be re-baselined as required. And hopefully the project can come in possibly under budget and ahead of schedule. Full oversight of the scope and budget will be provided to the Facilities Steering Committee (see Section 3.1 (A)) for their review and evaluation as described in Section 3.2 and 3.3.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The project within this business case will impact the Pullman Service Center Team. The team will be able to work out of the current service center during construction but we will be reaching out to the team during the design and construction phases.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

ER7001 Facilities Structures and Improvements is a 5-year program created to address the capital lifecycle asset replacements and business/site improvements at all of Avista's regional sites and offices. Asset lifecycle replacements are compiled by Facilities and are based on an asset condition report and industry recognized lifecycles. Site improvement projects are approved based on productivity and/or business need.

Asset Lifecycle Replacement Projects

In 2017 Avista hired Terracon Consultants to perform a condition assessment on 76 Avista-owned facilities and 35 real estate sites at 34 different locations, comprising approximately 981,000 square feet. These facilities were constructed between 1903 and 2016. Terracon estimated the value of this infrastructure at approximately $242 million.

The Terracon study was highly detailed and in depth. They examined every characteristic of each facility from a variety of perspectives. External structures from asphalt in the parking lot to roof condition, fences, curbs, work, and storage areas were examined to ascertain and score condition and to identify issues and note concerns. Internal aspects such as walls, carpets, and furniture condition were evaluated.

They surveyed building systems including plumbing, heating and cooling, electrical, lighting, air quality, drainage, and security. They also looked at safety aspects from both the customer and employee perspective. Then each item in the facility was rated based upon its condition and assigned a budget category of O&M Preventative Maintenance, O&M Deficiency Repairs, Capital Replacement, and Capital Renewal/In-Kind Replacement. Terracon's list is sorted by relative risk and the impact the item has on the Company's ability to perform its work, making the highest priority projects readily apparent. Of the 363 "at risk" items Terracon identified, nearly 60% had a risk rating higher than 5 (on a 1 to 10 scale) and 20% were identified as having an actual impact on operations. This rating is what is used to identify the highest risk replacements needed and the project list is created using this information.

ER 7001/ 7003 Structures and Improvements

Site Improvement Projects

These types of requested facilities projects undergo a multi-level internal review process. It begins with the related manager who either identifies the capital need themselves or is notified of an issue that needs to be resolved by an employee. If the manager believes the project is in the best interests of his group and the Company, the proposal is submitted to that manager's director. If the director also sees the value of the request, it is submitted to a group known as the Facilities Capital Request Board.

This Board meets every fall to review the requested projects for the upcoming year. Managers from each major business area send a representative (the employee chosen usually changes every year). In addition, there is a requirement of at least one person from Operations, Environmental Affairs, Materials Management, and Facilities. This broad mixture of perspectives is designed to provide a neutral and "outside" perspective while having access to the expertise and experience of the directly related and impacted business entities.

By the time the Board receives the list of requests, it has already been vetted twice within its related department. The requests are prioritized based on the Capital Request form that was filled out and approved. At the Board level, each request is reviewed for required criteria such as risk, safety, environmental impact, and compliance. Thus this process is designed to ensure that multiple stakeholder participation provides a thorough and robust analysis of all facility needs and alternatives across the Company.

3.2 Provide and discuss the governance processes and people that will provide oversight

Facilities Capital Steering Committee

Once the project list is assembled, the finalized list of projects is approved by the Capital Facilities Steering Committee. This Committee of Directors is responsible for approving the submission of Business Cases to the Capital Planning Group and approval of projects and any changes within this program.

In the past this has most often been:

- Director of Shared Services
- Director of Environmental Affairs
- Director of Financial Planning and Analysis
- Director of Generation, Production, Substation Support
- Director of IT and Security
- Director of Natural Gas

The project shall use certain Project Management Professional (PMP) guidelines and procedures during the course of this project.

A Project Execution Plan, consisting of the documents below, will be drafted and approved by the SteerCo described in Section 3.1 (A).

- Project Charter, Change Management Plan, Communication Management Plan, Cost Management Plan, Procurement Management Plan, Project Team Management Plan, Risk Management Plan and Risk Register, Schedule Management Plan, Scope Management Plan, and Project Execution Approval Form.

Each month, the project manager will provide the following information either at the scheduled SteerCo meeting, or via email.

- Approved Yearly Budget, Accrued Yearly to Date, Year Estimate at Complete, Year Variance at Complete, Approved Lifetime Budget, Accrued Life to Date, Lifetime Project Estimate at Complete, and Lifetime Project Variance at Complete.

Each month, the SteerCo will make decisions on cost, scope, or budget items as required by the Project Execution Plan. The project manager reserves the right to present items not outlined in the Project Execution Plan if he/she determines its importance is relevant to SteerCo input.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The final decisions regarding these items, especially certain change requests as required by the Project Execution Plan, will be presented to, and voted upon by the SteerCo. The decisions will be documented in a monthly meeting minutes of the SteerCo for documentation and oversight.

It will be the Project Manager's role to monitor the scope, budget, and schedule and present the results to the SteerCo, regardless of they are within tolerances, or not.

The undersigned acknowledge they have reviewed the ER 7001/ 7003 Structures and Improvements 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: Eric Bowles Date: 8/3/2020

Print Name: Eric Bowles

ER 7001/ 7003 Structures and Improvements

Title: Corporate Facilities Manager

Role: Business Case Owner

Signature: Dan Johnson

Date: 8/3/2020

Print Name: Dan Johnson

Title: Director Shared Services

Role: Business Case Sponsor

Signature:

Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Telematics 2025

EXECUTIVE SUMMARY

Fleet operations across the US and within the utility industry are implementing telematics solutions to solve complex business problems. The Advisory Group has identified five ways that vehicles on the road impact Avista. The first represents the first generation of telematics and is focused on utility owned trucks. The next four have the potential to positively or negatively impact our business but they are vehicles not owned by the Avista. It could be the contractor working for Avista in a contractor owned truck, a contractor in their personal vehicle, Avista's employee's doing business on behalf of the utility in their personal vehicle and crews responding to mutual aid in our service territory. Telematics has been implemented on the Avista's fleet since 2012. The first generation of telematics was implemented to streamline and track the inspections of trucks and mounted equipment. The digitization of inspections has been very successful and has improved the tracking of federally required inspections and the administration of those records as required by the same authorities.

In February 2022 our current provider has notified us that the 3G network that nearly 500 devices connect to will sunset. This network shut down forces us to invest capital in an upgrade. Additionally, customer requirements and our strategy to put the customer at the center of every decision necessitate the need for us to leverage vehicle location data on a modern and timely platform. Finally, best in class utilities are using telematics to provide both coaching to drivers and collecting leading indicators on decisions a fleet of drivers are making. The Advisory Group's recommendation is to replace Zonar telematics with a modern cloud platform system from Verizon Connect or Utilimarc-Geotab. Both platforms address latency issues and integrate more info sources than ever before. The final estimated cost for this is upgrade $2,387,500 spread over three years. An upgraded system will integrate location data with the CX platform to give our customers accurate response info, safer roads for all and lower overall costs by streamlining our operations with data. We must begin this investment in 2021 with the February 2022 shutdown of the AT&T 3G network coming. In doing nothing we will lose our ability to complete a critical compliance function by being unable to complete our daily vehicle inspections. Additionally, we fail to meet our customers where they expect us to be in today's digitally connected economy.

VERSION HISTORY

Version	Author	Description	Date	Notes
ExeSum	Greg Loew	Exe summary only	7/7/20	
Rev1	Greg Loew	Completed case	7/24/20	

Telematics 2025

GENERAL INFORMATION

Requested Spend Amount	$2,387,500
Requested Spend Time Period	*3 years*
Requesting Organization/Department	Fleet Services
Business Case Owner | Sponsor	Greg Loew | Dan Johnson
Sponsor Organization/Department	Energy Delivery
Phase	Planning
Category	Project
Driver	Asset Condition

Telematics 2025

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Advances in technology, customer requirements and safety are driving the need to invest capital in our connected vehicle systems. Implementing the next generation of telematics in vehicles on the road operating on behalf of Avista have the opportunity to delight our customers, reduce our liability exposure and improve operational safety.

Technological Changes: Telematics works by connecting the vehicle to the cellular data network. Currently, most telematics connectivity use third generation networks (3G) provided by the major carriers. In February 2022 this network will no longer be supported and many carriers are already preventing new 3G devices on their networks. To ensure current functionality we will need to equip our vehicles to connect to the fourth and fifth generation networks (LTE and 5G respectively). We also know that connected worker solutions are proliferating across our workforce. This has driven numerous data connections inside and outside of the vehicle. Telematics technology has advanced to allow the consolidation of connections. Leading telematics providers have embraced a platform perspective. They have acknowledged that original equipment manufacturers are controlling some of the data flow from the vehicle or like Caterpillar it is just build in to the equipment computer. This migration to a platform is beneficial for Avista as we advance solutions for the fully digitized worker of the coming decade.

Customer Requirements: Our customers are being influenced by Amazon and Google and other leading customer experience companies. They expect timely and relevant communications from everyone they do business with. The utility is not exempt from these expectations. Next generation telematics is an enabling technology for a fully integrated and digital field work process. The connected vehicle and worker, integrated with the mobile work management system and customer experience platform will provide greater visibility about where our field personnel are and when they will arrive. The information will be available to employees and to customers, improving our ability to provide firm estimates of when we will be there to complete the work. The platform will also improve emergency response times through improved routing and real time location services. Finally, providing more crew location information to our dispatchers will allowing us to dispatch the crew closet to the work saving valuable time and resources.

Safety: The impact of telematics on the overall safety to a fleet of vehicles is under estimated. Telematics allows the capture of data around all facets of the drive cycle. More importantly, telematics is to several leading indicator safety metrics. Next generation telematics integrations will allow us to see items as specific as seat belt usage, the engagement of reverse or how close we backed up to an object. Telematics also has the ability to coach drivers in real time and or provide them a summary of their performance on a pre-determined interval. Finally the next generation systems will provide metrics on the co-location of supervisors to the crews which has been proven to be a major predictor in crew safety performance

Additionally, as the Advisory Group has engaged internal stakeholders we have created a required functionality list. Based on current published Zonar capabilities the following issues with Zonar were identified:

Issue	Impact on Capability
Dynamic Reporting	Provides inconsistent data points
Server based system	5-8 minute lag in actual unit status
Only support Android operating system	Avista has standardized on iOS
No vehicle as a hotspot capability	Multiple connections and expense
Driver coaching	Requires dedicated tablet
Workflow management	No integrations or partnerships
Behavior metrics	No metrics outside of speed to posted
Auxiliary system data capture	No 3rd party device integration
Point designed solution	No platform capabilities at this time
No manufacture API integration	Requires us to always us an ancillary device

Telematics 2025 will initially provide a platform for compliance. We can and will continue to measure inspections completions and other safety related functions. We will use this platform to capture, track and communicate this information to users and leaders. A feedback loop to the driver on their driving performance will be a key feature of this initiative. Over time the advanced telemetry data from this system will help us shrink the gap between actual behaviors and expected behaviors.

The Driver Safety team that was stood up in 2017 identified a dozen key actions to improve our vehicle incident rate. These recommendations where based on the analysis of multiple best in class companies and the programs/practices they had in place to achieve such results. Every program we looked at had some sort of driver performance feedback mechanism.

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

Asset Condition

Telematics 2025 is also an enabling platform for Customer Experience advancements and Business Intelligence. We could measure improvements in customer satisfaction, reduced maintenance costs, and lower overall cost per customer being driven by fleet related activities.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The 3G network that Zonar currently operates on will cease operations in February of 2022. Our DOT/FMCSA compliance with CFR49 and the inspections required before and after operation are digitally managed. Not doing anything will force our commercial vehicle operators to complete inspections by pen and paper and creates a document management challenge because we must keep them for 12 months before disposing of them. Failure to do so opens the company to additional liability.

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.

Cost Savings: Estimated savings to the organization will be driven both directly and indirectly through multiple factors. Savings are ranked from initial platform deployment to additive next generation work management solutions to be deployed by future

- ✓ Compliance and regulatory costs—Avoided cost from effort and resources to once again track vehicle inspections with paper and the increased risk due to the inspection records not being correctly maintained per US Department of Transportation regulations 49CFR
- ✓ Automated recording of miles—Current work flow requires over 50% of Avista vehicles to submit mileage in paper form. Up to 25% of mileage is not turned in and as such vehicle use cost are not being fairly distributed to all users.
- ✓ Assuming data plan aggregation can occur while still supporting the critical business functions of the workers in the field, anticipated savings from reduced network connections in the vehicles are estimated as follows:

Vehicle Quantity	Data Plan Cost
80	$40.52/month
Total Cost Savings Per Year	$38,900

- ✓ Improved utilization—Currently, we average 11% less in miles and hours than the industry. 30% of fleet vehicle get less than 50% of the class average miles per year. By improving utilization we can spread our fixed cost across more miles and work to lower the fleets total fixed costs by reducing complement.
- ✓ Improved maintenance using advanced business intelligence tools and data—Revised maintenance programs could save up to $170,000 per year in total maintenance costs. This would be achieved by moving vehicles to a usage based maintenance model in which the collection of mileage data by the system alerts us to do a PM only when it approaches a use threshold.
- ✓ Less vehicles because of improved capabilities to share assets among some groups of workers—Reduced total fleet acquisition costs, higher utilization, reduced fixed and variable expenses.
- ✓ Improved routing and fuel savings—New operations driven tools could reduce total fuel consumption by expediting vehicles from job to job.
- ✓ Customer Service savings driven by reduced calls to the call center—The three year average for complaint calls related to vehicles and the potential whereabouts of people doing work on behalf of Avista totals 55 call hours per year using customer complaint records and an average call duration of 6.5 minutes.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

See the Driver Safety Team report out February 2018 by Greg Loew and Tony Klutz

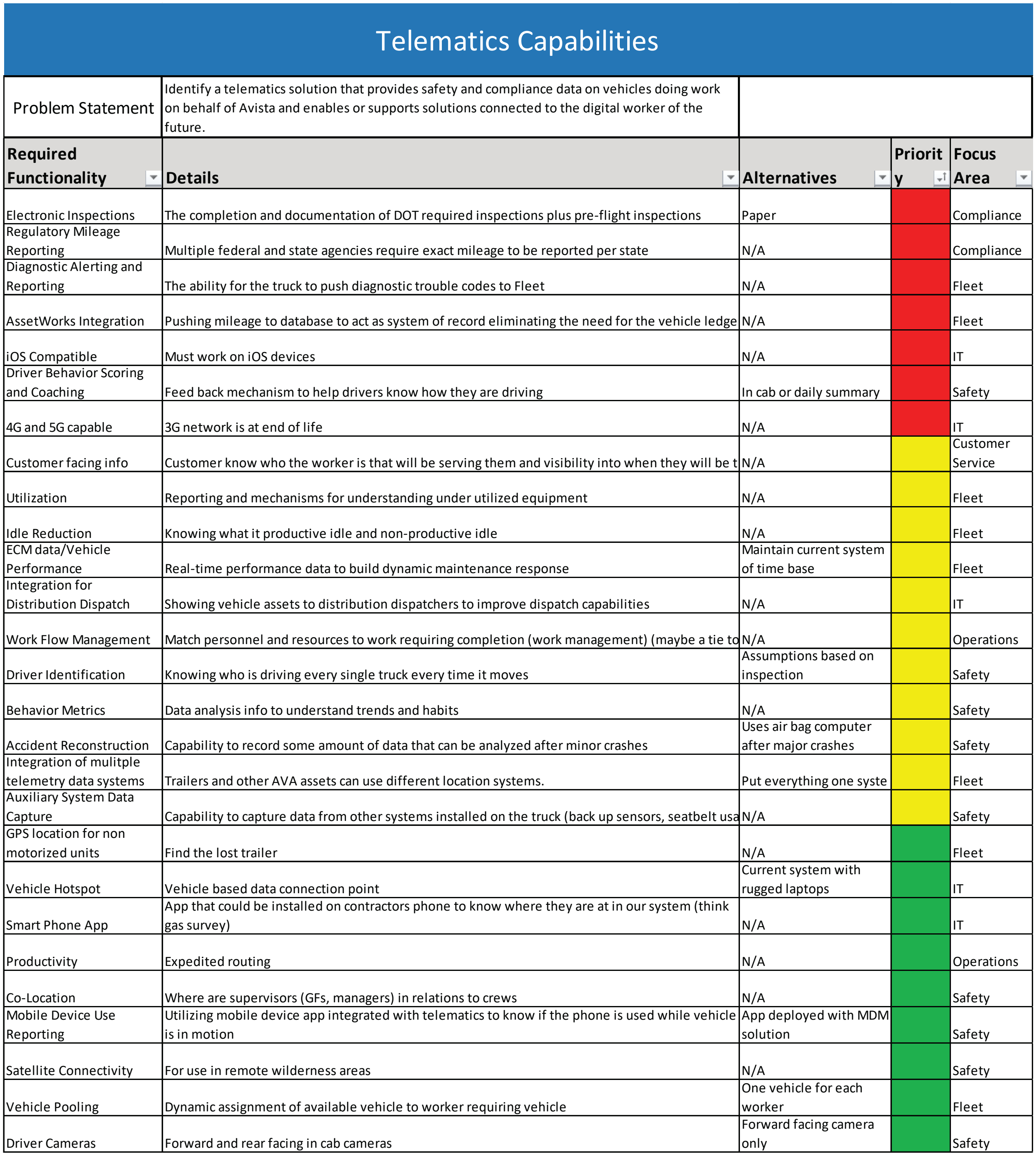
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The current network for Zonar will cease operation in 2022. As noted in section 1.1 several functions were noted as missing for future anticipated business processes.

Option	Capital Cost	Start	Complete
Implement Telematics 2025	$2,385,500M	01 2021	06 2023
Partial implementation of Telematics 2025	$1,850,000M	01 2021	12 2021
Upgrade Zonar to 4G devices	$157,500	03 2021	10 2021

Telematics 2025

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.



Telematics Capabilities

Problem Statement	Identify a telematics solution that provides safety and compliance data on vehicles doing work on behalf of Avista and enables or supports solutions connected to the digital worker of the future.	

Required Functionality	Details	Alternatives	Priority	Focus Area
Electronic Inspections	The completion and documentation of DOT required inspections plus pre-flight inspections	Paper	🟥	Compliance
Regulatory Mileage Reporting	Multiple federal and state agencies require exact mileage to be reported per state	N/A	🟥	Compliance
Diagnostic Alerting and Reporting	The ability for the truck to push diagnostic trouble codes to Fleet	N/A	🟥	Fleet
AssetWorks Integration	Pushing mileage to database to act as system of record eliminating the need for the vehicle ledge	N/A	🟥	Fleet
iOS Compatible	Must work on iOS devices	N/A	🟥	IT
Driver Behavior Scoring and Coaching	Feed back mechanism to help drivers know how they are driving	In cab or daily summary	🟥	Safety
4G and 5G capable	3G network is at end of life	N/A	🟥	IT
Customer facing info	Customer know who the worker is that will be serving them and visibility into when they will be t	N/A	🟨	Customer Service
Utilization	Reporting and mechanisms for understanding under utilized equipment	N/A	🟨	Fleet
Idle Reduction	Knowing what it productive idle and non-productive idle	N/A	🟨	Fleet
ECM data/Vehicle Performance	Real-time performance data to build dynamic maintenance response	Maintain current system of time base	🟨	Fleet
Integration for Distribution Dispatch	Showing vehicle assets to distribution dispatchers to improve dispatch capabilities	N/A	🟨	IT
Work Flow Management	Match personnel and resources to work requiring completion (work management) (maybe a tie to	N/A	🟨	Operations
Driver Identification	Knowing who is driving every single truck every time it moves	Assumptions based on inspection	🟨	Safety
Behavior Metrics	Data analysis info to understand trends and habits	N/A	🟨	Safety
Accident Reconstruction	Capability to record some amount of data that can be analyzed after minor crashes	Uses air bag computer after major crashes	🟨	Safety
Integration of mulitple telemetry data systems	Trailers and other AVA assets can use different location systems.	Put everything one syste	🟨	Fleet
Auxiliary System Data Capture	Capability to capture data from other systems installed on the truck (back up sensors, seatbelt usa	N/A	🟨	Safety
GPS location for non motorized units	Find the lost trailer	N/A	🟩	Fleet
Vehicle Hotspot	Vehicle based data connection point	Current system with rugged laptops	🟩	IT
Smart Phone App	App that could be installed on contractors phone to know where they are at in our system (think gas survey)	N/A	🟩	IT
Productivity	Expedited routing	N/A	🟩	Operations
Co-Location	Where are supervisors (GFs, managers) in relations to crews	N/A	🟩	Safety
Mobile Device Use Reporting	Utilizing mobile device app integrated with telematics to know if the phone is used while vehicle is in motion	App deployed with MDM solution	🟩	Safety
Satellite Connectivity	For use in remote wilderness areas	N/A	🟩	Safety
Vehicle Pooling	Dynamic assignment of available vehicle to worker requiring vehicle	One vehicle for each worker	🟩	Fleet
Driver Cameras	Forward and rear facing in cab cameras	Forward facing camera only	🟩	Safety

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.

Telematics 2025 will be implemented over a three year period beginning in 2021 in order to meet 3G obsolescence. In year one our commercial fleet will be functional and on the new systems. In years two and three we will bring our light duty vehicles fully on to the platform plus trailers and complete integrations to systems like Assetworks, Intelex and Oracle.

On an ongoing basis the operational costs for telematics flow to the Fleet Clearing Account. From there a portion of the costs go to capital and some to O&M depending on the class of vehicle. Vehicle rates for light duty trucks and trailers will see a small impact from this technology.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Telematics 2025 will continue to be used by Fleet and Distribution Ops. The CX project will use the data stream from this system as described in section 1.1. Vehicle electrification efforts have the potential to tap into the platform.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Upgrade existing system. Preserve current functionality with technology that does not meet current or future business needs across the enterprise.

Partial install on only the on-road portion of our fleet (excludes trailers)

Partial install of new system on commercial motor vehicles only. Preserves current functionality does not integrate or capture almost a third of all Avista owned vehicles. Many safety and operational benefits would not be met.

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.

$1.1M	Q1-2021 Project planning	Q2-2021 Product ordering	Q3-2021 Vehicle installs TTPs as districts or orgs completed	Q4-2021 Project planning and remaining TTP
$675K	Q1-2022 Planning and SOW	Q2-2022 Integrations, installs and TTP	Q3-2022 Remaining 2nd year project TTP	Q4-2022
$612.5K	Q1-2023 Planning and SOW	Q2-2023 Integrations, installs and final TTP	Q3-2023	Q4-2022

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Enhancing the telematics in the fleet vehicles directly aligns with the four focus areas; customers, people, perform and invent.

Customers are better served by providing a platform that enables notifications and awareness of crew arrival times. Avista **Employees** are better served through interactive coaching and feedback on their driving behavior. **Performance** is better served through the enhanced integrations that are enabled and the information that can be shared across multiple systems. **Invention** is served by recognizing that the expectations of customer service has changed, and that technology is required, not only in our back office but in the front-line vehicles that serve as the initial touchpoint for many customer interactions

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

The majority of Telematics 2025 scope is the replacement of a system that will no longer operate after February 2025. As outlined in section 1.1 our next generation telematics will enable additional functions and help streamline analog processes. Project management and business case owner will continue to review the scope of the project for material changes.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholder Name	Department
Andrea Pike	Customer Service
Reuben Arts	Distribution Dispatch
Amy Parsons	Finance
Mike Faulkenberry	Gas Ops
Alexis Alexander	GPSS
Mike Littrel	Enterprise Technology
Jon Thompson	Enterprise Technology

2.8.2 Identify any related Business Cases

None at this time

3.1 Steering Committee or Advisory Group Information

Mike Littrel	Erica Ellis	Kim Boynton
Matt Redding	Eric Rosentrater	Jason Johnson
Steve Aubuchon	Russ Feist	Jim Corder

3.2 Provide and discuss the governance processes and people that will provide oversight

This project reports in with the executive advisory committee comprised of:

Heather Rosentrater	Jason Thackston	Jim Kensok
Bryan Cox		

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The project manager and the business case owner will be responsible for monitoring and recording priority changes and material change requests. Full values and scope to be determined at a later date.

Exh. HLR-2

The undersigned acknowledge they have reviewed the Telematics 2025 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: Gregorymloew Date: 7/24/20
Print Name: Gregory Loew
Title: Fleet Manager
Role: Business Case Owner

Signature: Dan Johnson Date: 7/28/2020
Print Name: Dan Johnson
Title: Director, Shared Services
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title: Shared with committee on 7/24/20 via email
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

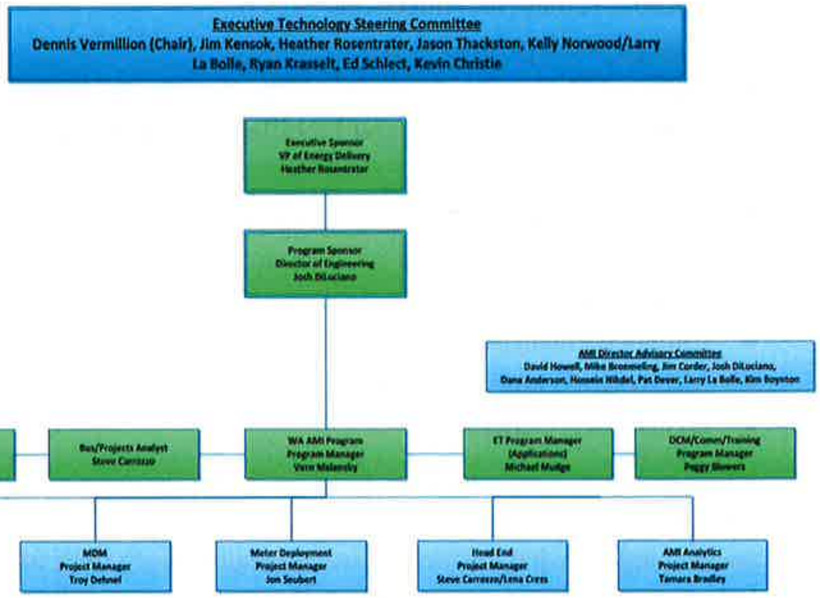
Washington Advanced Metering Infrastructure Project

1 GENERAL INFORMATION

Requested Spend Amount	$165,000,000
Requesting Organization/Department	Energy Delivery/Energy Delivery Tech. Projects (P03)
Business Case Owner	Vern Malensky
Business Case Sponsor	Josh DiLuciano
Sponsor Organization/Department	Electrical Engineering/Energy Delivery Tech. Projects
Category	Project
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

Energy Delivery Technology Projects (EDTP)
WA AMI Program Organization Chart
4/11/17



Based on the organizational structure identified above, Project Everest, Advanced Metering Infrastructure (AMI) is ultimately governed by the Executive Technology Steering Committee (ETSC), which meets monthly to review the overall program in detail from a scope, schedule, and budget standpoint. Additionally, the AMI Advisory Committee meets bi-weekly to review more granular information regarding the scope, schedule, and budget of each of the individual projects under Project Everest.

2 BUSINESS PROBLEM

Avista is committed to a path of high customer satisfaction, which includes, among other things, offering its customers information and choices that help them manage their energy costs. Avista views advanced metering infrastructure as an enabling technology key to this mission. Advanced metering has emerged as a powerful solution among a range of smart grid technologies that enables utilities to improve responsiveness to customer needs, improve information sharing with customers, and ultimately improve overall customer service. In preparation for this commitment, Avista led the Pullman Smart Grid Demonstration Project (SGDP) to gain a better understanding of the customer benefits related to AMI. The Washington AMI Project [1]will build on past Company experience on the Pullman SGDP to provide customer and operational benefits to Avista's Washington customers through the installation of Advanced Metering Infrastructure. The project, which will encompass all of Avista's Washington service territories (excluding Goldendale and Stevenson) and last approximately six years, will deploy advanced meters to approximately 253,000 electric customers and 155,000 gas customers.

The objectives of the Project are to provide the following customer benefits:

- Access to Interval Energy Usage Data
- Including Home Area Network (HAN) interface technology in meters for future use
- Energy Alerts
- Customer Property Privacy
- Future Opportunities for Benefits
- Migration from Manual Meter Reading
- Remote Rapid Reconnection
- Outage Management
- Energy Efficiency – Customer Opportunity and Distribution System
- Energy Theft Detection and Unbilled Energy Usage
- Billing Accuracy
- Utility System Studies
- Utility Employee Safety
- Rate Options
- Enhanced Data Analytics
- Micro Grids and Smart Cities
- Distributed Generation

Ultimately, Avista's Project Everest is the enabling platform for many, if not most, of Avista's future offerings to customers. When evaluating the corporate vision and understanding what customers are requesting from their utilities, AMI technology is required before any of these opportunities for customers can become a reality. If this project was deferred, it puts these opportunities at risk.

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[1] While the business case here is described as the Washington AMI Project, the Meter Data Management project will be applied to all jurisdictions, not just Washington.

Washington Advanced Metering Infrastructure Project

For more detailed information regarding the quantifiable costs/benefits, including the full cost benefit analysis, please review the 2016 AMI Business Case document as filed in the 2016 Washington General Rate Case. Figure 1 below shows the resuilts of the cost-benefit analysis for the Washington AMI project over the project lifecycle.

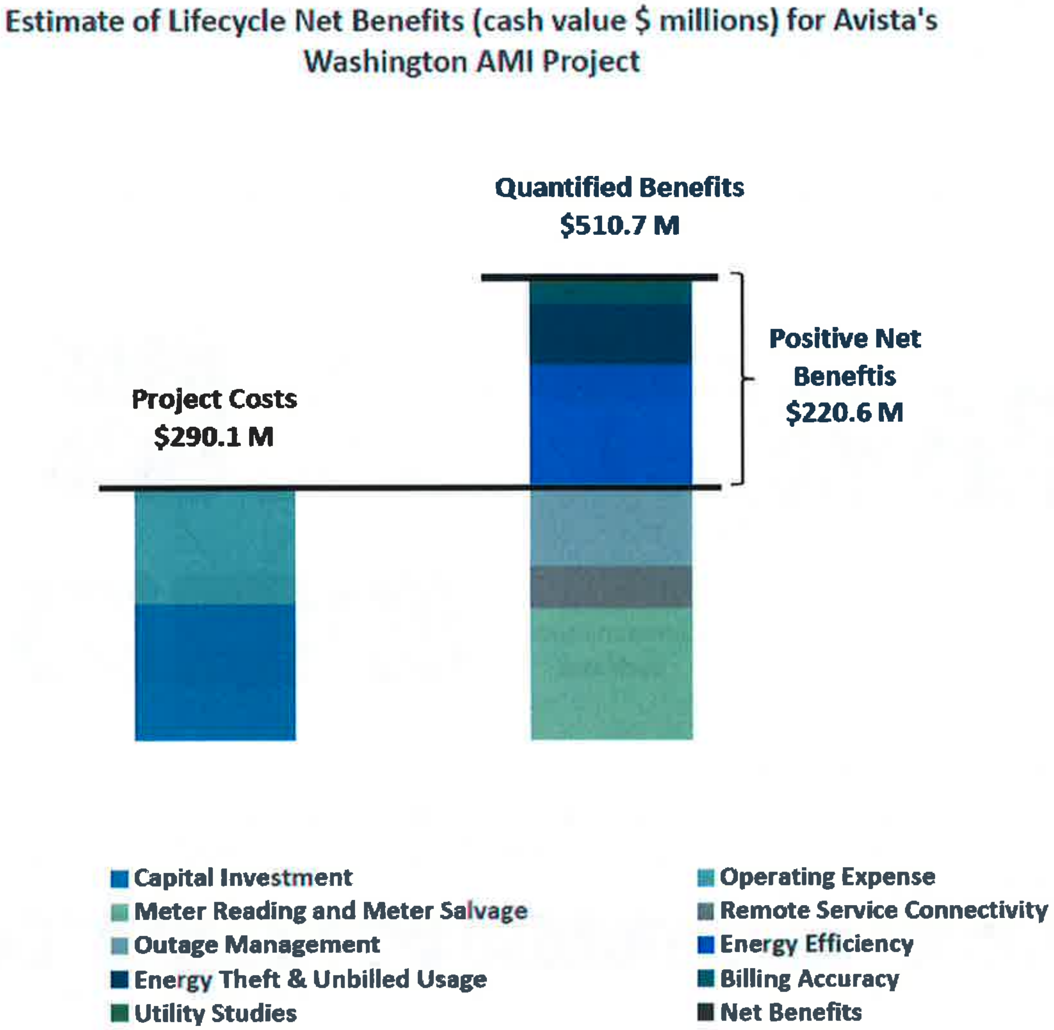

Figure 1: Washington AMI Cost-Benefit Analysis as submitted in the 2016 Washington General Rate Case.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Washington AMI Deployment (Preferred Alternative)	*$165M*	*01/2015*	*03/2021*
Washington Automated Meter Reading (AMR) Deployment	*N/A*	*01/2015*	*03/2021*

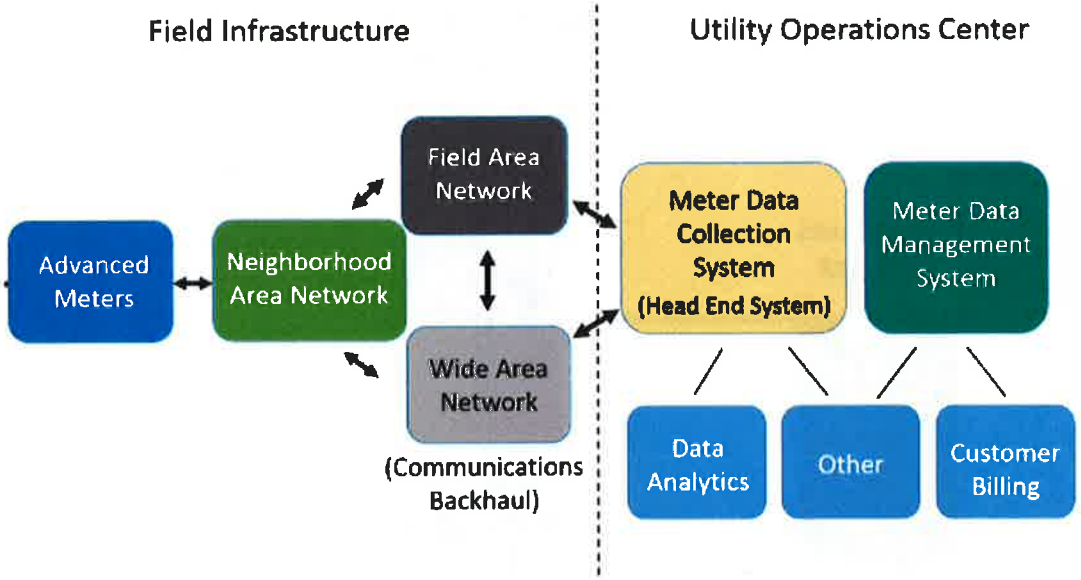

Figure 2: AMI System Architecture

In general, Figure 2 depicts the high level architecture of an AMI system. The following table describes the five different projects under Program Everest which make up the Avista AMI Solution.

Component	Acronym	Description
Meter Data Management	MDM	Software and hardware which will be the system of record for meter consumption data, including estimation and validation activities.
Head End System	HES	Software and hardware necessary to communicate with the advanced meters and modules and to transfer meter consumption data to Meter Data Management.
Collection Infrastructure (Neighborhood Area Network, Field Area Network, Wide Area Network)	CI	Network equipment installed in the field on poles or streetlights to help transfer meter data from the advanced meters to the head end system.
Meter Deployment	MD	Physical installation of the advanced meters and modules on customers’

(Electric Meters and Gas Modules)		premises, including the communication with customers regarding the installation.
Data Analytics	DA	Software and hardware necessary to analyze the metering data to achieve the required customer benefits as defined in the AMI Business Case.

As part of the AMI Business Case process, a formal staffing and support plan has been identified as well which estimates what additional staffing requirements will be required, by system, as well as what roles will no longer be required due to this implementation. Additional information on this plan is available and can be provided, as needed.

Prior to formalizing the plan to move ahead with AMI technology as the preferred alternative, Avista analyzed two other options:

1. No change – Continue using non-AMI technology.
2. Deploy Automated Meter Reading (AMR) technology, similar to what was deployed in our Idaho services territories 11 years ago.

In general, the risks for each of the following alternatives are described below:

1. No change: This alternative creates risk by impacting Avista's ability to meet and manage customer expectations while also providing additional value in other areas, including energy efficiency, increases in solar penetration, distributed energy resources, advanced rate options, etc. Unmanaged load variations can result in system wear and the inability to optimize demand with supply. The "No change" alternative inhibits Avista's ability to adapt to changes, which also can have a negative impact on O&M trying to maintain legacy metering systems.
2. Washington AMI Deployment: The risk with this option is that the total project costs may exceed the customer benefits within the proposed project timeframe. This risk was mitigated through past experiences with AMI technology and deployments in the Pullman Smart Grid Demonstration Project. Additionally, a very robust business case, including cost benefit analysis, was generated as part of the 2016 Washington General Rate Case process to highlight how this project will positively affect our Washington customers.
3. Washington Automated Meter Reading (AMR) Deployment: The risk with this option is the customer benefits are much smaller when compared to AMI. Specifically, AMR provides no quantifiable benefits above the O&M savings associated with moving away from meter reading. This technology is not an enabling platform for future customer benefits, but rather an obsolete technology which is being replaced by AMI in many cases. This alternative does not meet the long term goals of Avista or its customers, which can include distributed energy resources, etc.

Ultimately, the decision to move forward with AMI technology came down to the fact that no other alternative met the needs of our customers from an expectations and benefits perspective. Additionally, the AMI alternative was the only alternative which met Avista's strategic goals and vision related to customer service and products and services. The urgency for AMI is related to how it fits in Avista's long term strategy for proving customer benefits. Because it is the enabling technology for many of the items in Avista's short and long term plans, this technology must be implemented as soon as possible. Delays in execution of this project will result in decreased customer benefits and increased O&M expenses in the short term while the technology is implemented. The value of the other alternatives fell short of expectations, especially when considering the AMI platform is the enabling technology for many of Avista's future endeavors regarding customer experience and expectations.

A complete cost analysis was performed for this project, which provides justification for the total estimated capital expenditures, estimated O&M impacts, and estimated overall customer benefits. For additional information on this analysis, please refer to the 2016 AMI Business Case.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Washington Advanced Metering Infrastructure Project and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 4/17/17
Print Name: Vern Malensky
Title: AMI Program Manager
Role: Program Manager

Signature: Date: 4/17/17
Print Name: Josh DiLuciano
Title: Director, Electrical Engineering
Role: Business Case Sponsor

Signature: Date: 4/23/17
Print Name: Heather Rosentrater
Title: VP, Energy Delivery
Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Vern Malensky	04/11/17	Josh DiLuciano	04/10/17	Initial version

Template Version: 03/07/2017

Gas Cathodic Protection Program, ER 3004

1 GENERAL INFORMATION

Requested Spend Amount	$715,000
Requesting Organization/Department	B51 - Gas Engineering
Business Case Owner	Jeff Webb / Tim Harding
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Cathodic Protection (CP) group monitors system performance and recommends replacements and upgrades when corrosion control measures become ineffective. Gas Engineering evaluates the recommendations with the CP group and other interested parties. The pros and cons of each option are then reviewed with the Gas Engineering Manager and a preferred alternative is selected to proceed with a funding request. Gas Engineering is responsible for managing this program.

2 BUSINESS PROBLEM

CP system compliance is mandated by Federal Rules within the Department of Transportation code 49 CFR 192, Subpart I. Some of the CP systems have been in service at Avista for extended periods of time and they have exceeded their useful service life. This requires them to be replaced. It is often difficult to predict in advance when specific projects are required, because sudden component failures do occur. Anodes, a key component of the CP systems, are buried and not observable, deteriorate at differing rates, and become ineffective when they are used up. The estimated annual cost for this budget is based on past expenditures. Because of the unpredictable nature of these projects, it is not always know which service territory work will be performed in on any given year.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	**Capital Cost**	**Start**	**Complete**
Option 1 – Do nothing	$0	N/A	
Option 2 – Preferred Solution, Replace end of life cathodic protection systems	$800,000	January	December

Option 1 – Do nothing

CP systems have a finite lifespan and must be replaced when they are at the end of their service life. Failing to replace these facilities will result in inadequate external corrosion protection on Avista's steel piping systems. This would result in non-compliance with State and Federal Rules, as well as increased risk to both employee and public safety.

Option 2 – Preferred Solution, Replace end of life cathodic protection systems

Typical types of projects installed under this work type may include (but are not limited to) CP deep and shallow anode wells, Remote Monitoring Units (RMU), installation of CP rectifiers, shorted casing remediation, replacement of gas mains to improve CP system performance.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Cathodic Protection 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: Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Cmt Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Tim Harding	04/03/2017			Initial version
1.1	Jeff Webb	04/04/2017			
2.0	Tim Harding	2/12/2020	Jeff Webb		Revised for 2020 Oregon GRC filing

Template Version: 03/07/2017

Gas Cheney HP Reinforcement Project, ER 3311

1 GENERAL INFORMATION

Requested Spend Amount	$5,000,000 (2019)
Requesting Organization/Department	Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Planning department routinely runs an analysis (load study) on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve existing Firm customer loads on a design day (Avista defines design day as the projected system demand for a "coldest day on record" weather event). These deficient areas are given a priority level based on the severity of the risk associated with insufficient system capacity. The areas with the highest priority are selected for remediation and the project is assigned to Gas Engineering to evaluate options to provide sufficient capacity to meet Firm gas demands on a design day. Options are reviewed with Gas Planning, Gas Operations, and other interested parties. The pros and cons of each option are then reviewed with the Gas Engineering Manager and a preferred alternative is selected to proceed with a funding request.

2 BUSINESS PROBLEM

Load studies performed by the Gas Planning department as well as pressure monitoring during cold weather events has shown that there is insufficient pressure at the south end of the Cheney High Pressure (HP) pipeline that feeds the town of Cheney, Washington. During the most recent winter, cold weather drove the pressures at the end of the supply line to 136 pounds per square inch (psig). The line starts out at 240 psig at the source approximately 12 miles away. Sufficient capacity is defined as pressures at or above 15 psig in the distribution system and 90 psig on the HP system on a design day analysis. Without a reinforcement project, Avista will not have sufficient capacity to serve Firm customer load in the Cheney area on a design day scenario. In addition, there is a large industrial customer (Firm rate) that has expressed interest in increasing their load. Avista would not be able to meet the new request unless a reinforcement was completed.

The first segment of the Cheney HP pipeline supplies the Medical Lake area and was built in 1957, the second part that continues to Cheney was built in 1965. For years, Avista and a large gas user in Cheney have operated under a "gentlemen's agreement" where the customer switches from natural gas to an alternate fuel for periods of cold weather during the winter. Avista paid the incremental difference in fuel costs if the customer was asked to curtail natural gas use. The customer did this voluntarily and so enabled Avista to defer this reinforcement project for many years. The customer is now considering adding additional Firm load and possibly a cogeneration plant as well. This will further exasperate the gap between system capacity and customer demand, and forces the need to complete this reinforcement project.

Depending on the route chosen, the gas main could cross through areas not yet served by gas, providing the additional benefit of new growth. This project is still in the planning stage, additional load information needs to be firmed up before proceeding further with design and alternative analysis. Cheney has approximately 1400 gas customers.

Gas Planning is unable to properly model this area because the HP system does not have sufficient capacity to reach design day conditions of 82 HDD (Heating Degree Day, average daily temperature of -17 deg F). 62 HDD is as low as the model can go. As shown in Image 1, at 62 HDD the HP system is below 90 psig and many parts of the distribution system are below 15 psig. This model scenario assumes the large customer in Cheney is only using 20 thousand cubic feet per hours (Mcfh), well below their typical winter load of 60 Mcfh. This customer is requesting 150-250 Mcfh in the future, all Firm load.

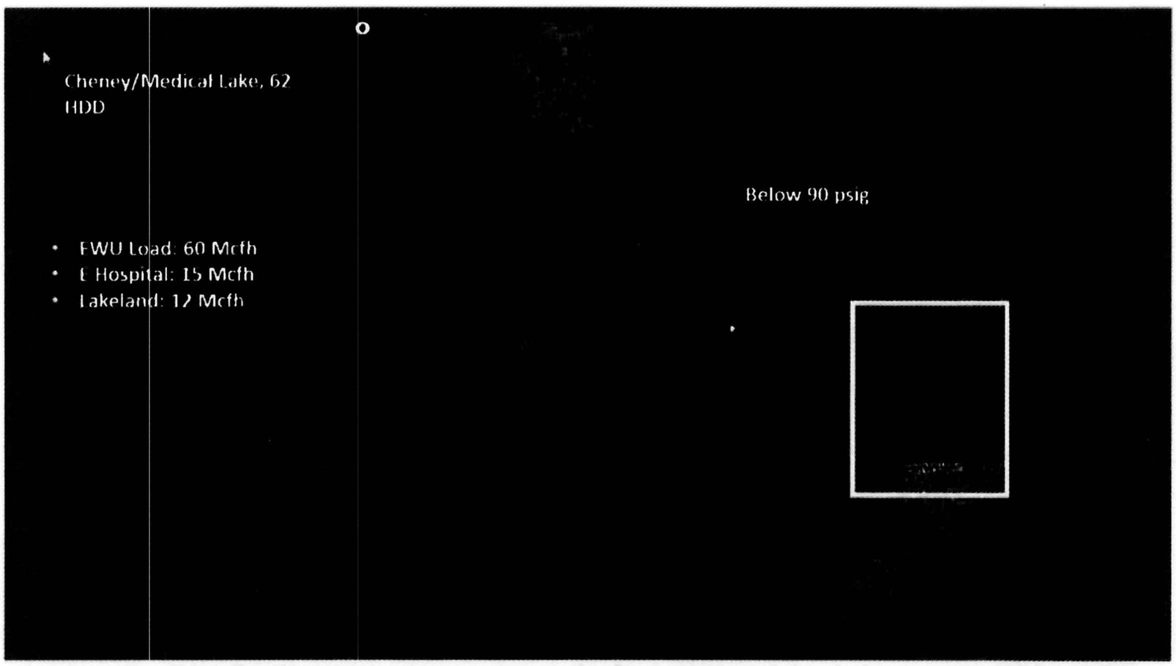

Image 1 – Distribution system pressures before proposed reinforcement (62 HDD is shown, design is 82 HDD)

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
Option 1 - Do nothing	$0	N/A		
Option 2 – Preferred Solution, Install new Gate Station and HP supply line from Spangle area	TBD	6/2018	12/2019	
Option 3 – Alternative #1, Upsize a portion of the existing HP supply line.	$5,000,000	6/2018	12/2019	
Option 4 – Alternative #2, Install new HP supply line from Airway Heights area	TBD	6/2018	12/2019	

These options are still being vetted out by the project team. Just recently Avista received from the large customer in Cheney their projected growth plans. This new information can now be used to determine the best course forward. Here is a high level summary with information known to date.

Option 1 – Do nothing

Without a reinforcement project, Avista does not have sufficient capacity to serve Firm customer loads in the Cheney, WA area on a design day scenario. See Image 1 for a load study analysis showing the Cheney distribution system with insufficient capacity to serve existing customers. Doing nothing would put the company at a high risk of outages starting at approximately 60 HDD. Additionally there would be no capacity available for the large customer in Cheney to expand their operations.

It is important to note that if service is lost during severe cold weather, gas service may not become available again until weather warms and customer demand decreases. Depending on the length of the outage, this can cause severe injury up to and including death to some customers.

Option 2 – Preferred Solution, Install a new Gate Station and HP supply line from the Spangle area

This option would provide the greatest flexibility by adding a new Gate Station (supply point into Avista's system) and HP supply line. The other two options are somewhat limited because they tap into existing systems, whereas this option creates a new dedicated tap that can be sized appropriately and will have few, if any, capacity limitations. This route will add reliability to the system by bringing in a second independent gas source to the area and will provide additional growth opportunities along the way for individuals without gas service. This reliability will be even greater because the new gas source will be served off another Interstate natural gas provider, GTN TransCanada. All existing lines and the other options are sourced from Williams NW Pipeline.

Option 3 – Alternative #1, Upsize the existing HP supply line (existing route)

This option would replace the existing 6" and 4" diameter supply line from the Medical Lake Gate Station with a larger diameter pipe along the same route. This would ease the workload from the Real Estate department as for most cases, existing permits and easements will cover this type of construction activity.

Option 4 – Alternative #2, Install a new HP supply line from the Airway Heights area (new route)

This option would extend a HP supply line from the existing 8" line that ends just south of the Airway Heights area. This route will add reliability to the system by bringing in a second independent gas source to the area and will provide growth opportunities along the way for customers without gas service. This would require significant work to acquire new permit and easements.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Cheney HP Reinforcement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 4-17-17
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: Date: 4/17/17
Print Name: Mike Faulkenberry
Title: Director of Gas Operations
Role: Business Case Sponsor

Gas Cheney HP Reinforcement Project, ER 3311

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	04/17/17	Mike Faulkenberry	04/17/2017	Initial Version

Template Version: 02/24/2017

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 (until the end of 2031). 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.

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 2016 through 2021 has been $20M-$23M annually and is reflective of the program's most recent cost experience updates. The requested budget amounts consider Avista's regulatory mandate to complete this program with full contractor complement and to adjust for the mileage that was not completed in 2020 and be in alignment with Distribution Integrity Management Program's (DIMP) prioritization recommendations. This also meets Avista's goal of investing in its infrastructure to achieve optimum life-cycle performance. Inflation of approximately 4% has been planned for by escalating the annual costs.

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 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.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Michael Whitby*	*Initial draft of original business case*	*2011*	
1	*Michael Whitby*	*Budget Change*	*2015*	*Additional $1.8M approved*
2	*Michael Whitby*	*Budget Change*	*2016*	*Additional $3M approved*
3	*Michael Whitby*	*Budget Change*	*2017*	*$2M deferred to 2018*
4	*Michael Whitby*	*Budget Change*	*2018*	*$1M deferred to 2019*
5	*Michael Whitby*	*Budget Change*	*2019*	*$1.5M deferred to 2020*
6	*Karen Cash*	*Budget Change*	*2020*	*$1,035,000 deferred to 2021*
7	*Karen Cash*	*Budget Change*	*2020*	*$1,000,000 deferred to 2021*
8	*Karen Cash*	*Budget Change*	*2020*	*$500,000 deferred to 2021*

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

GENERAL INFORMATION

Requested Spend Amount	$25,000,000 - $30,500,000 Annually
Requested Spend Time Period	10 years (2022 through 2031)
Requesting Organization/Department	Natural Gas / Gas Facility Replacement Program
Business Case Owner | Sponsor	Karen Cash / Mike Faulkenberry
Sponsor Organization/Department	Energy Delivery / Natural Gas
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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.

GFRP was initiated in 2012 and is planned to continue for 20 years (until the end of 2031). 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.

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.

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

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 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 **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 is deferred

To ensure Avista fulfills the regulatory mandate to complete this program.

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 acceptable. There is a potential harm to the public through

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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 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 objective of this investment and structured replacement program is to reduce risk by replacing at risk pipe and by rebuilding Service Tee Transitions. Through rigorous Project Management efforts, the GFRP plans and tracks the performance of the projects, and utilizes Earned Value for cost analysis and for upstream reporting. Further, the GFRP tracks and reports Planned vs. Actual quantities by project, by year, by state jurisdiction, and also reports multi-year cumulative statistics.

1.5 Supplemental Information

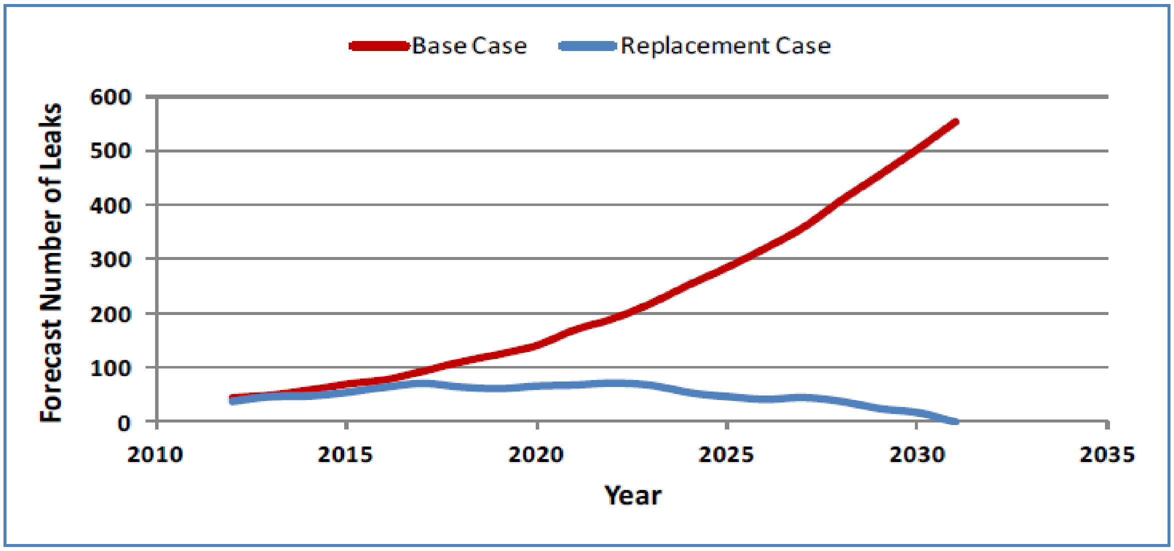
1.5.1 Please reference and summarize any studies that support the problem

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

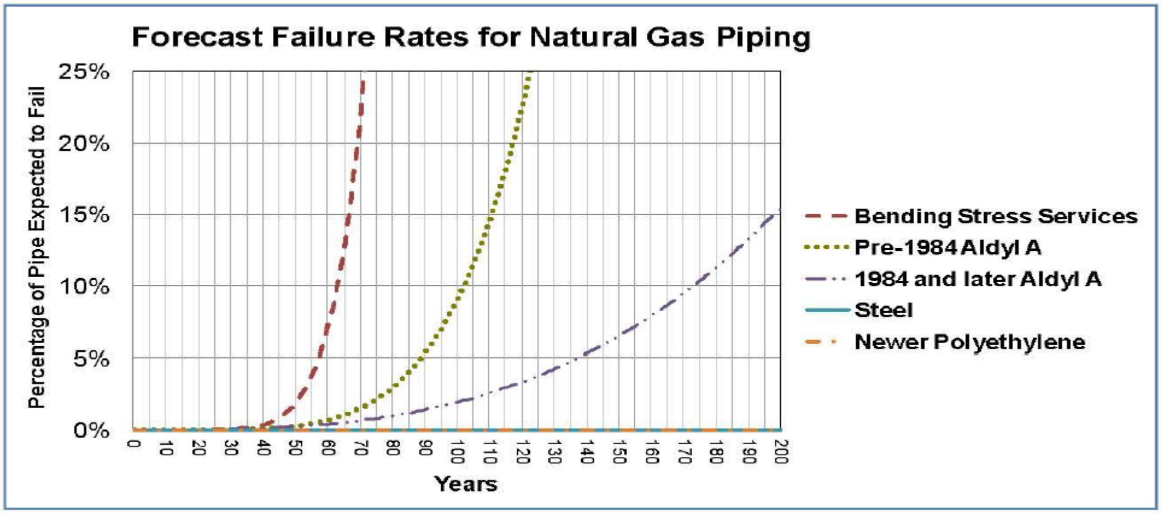
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

The 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



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.



2. PROPOSAL AND RECOMMENDED SOLUTION

“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.

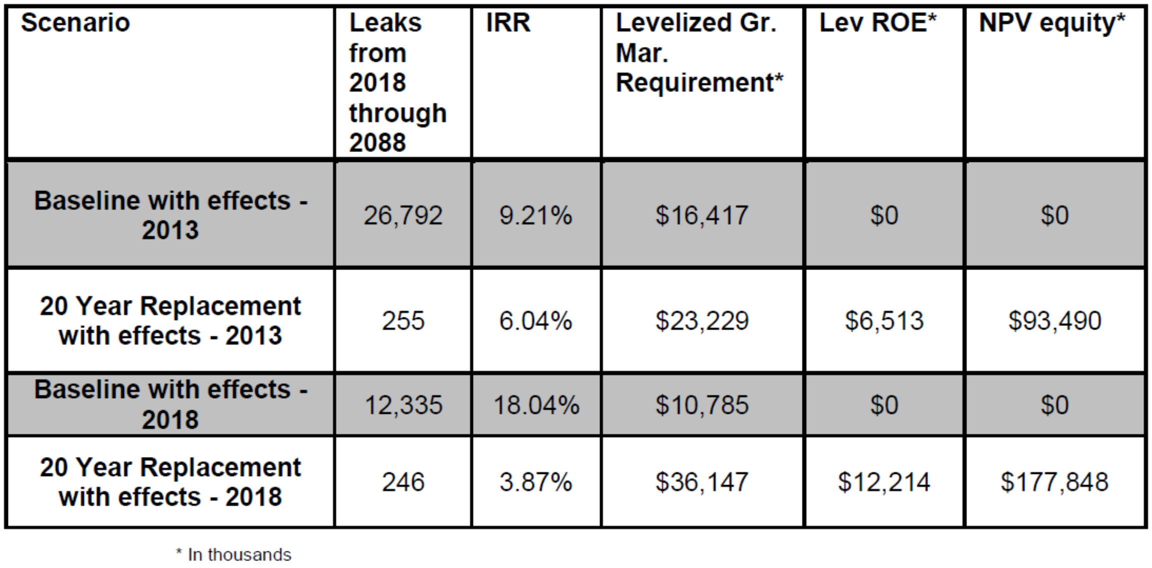
The Aldyl-A Pipe Replacement effort has been proposed and planned as a systematic twenty-year pipe replacement program. The program is expected to have a nominal impact to existing business resources, functions, and processes since the GFRP has been structured to function as a “stand alone” program consisting of 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-year timeframe	≈ $443M	January 2012	December 2031

The 2013 Avista Study of Aldyl-A Mainline Pipe Leaks was updated in 2018 based on the upon leaks and replacements through the end of 2017. The original study developed failure distributions that described the likelihood of leaks occurring on the Aldyl-A pipe installed by Avista for natural gas distribution and to evaluate multiple replacement scenarios. According to the table below the baseline scenario remains more cost effective when compared to the replacement strategies.



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

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Reference key points from external documentation, list any addendums, attachments etc.

The 2013 Avista Study of Aldyl-A Mainline Pipe Leaks was updated in 2018 based on the upon leaks and replacements 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 the worst pipe already replaced. If the 20-year replacement program where all Aldyl-A pipe is removed continues there is a slight reduction in the expected number of leaks, 255 in the original study and 246 in the updated model.

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 20-year 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.

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.

[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.]

Over the duration of the 20-year program, the GFRP will conduct replacement and rebuild work in virtually every gas district across Idaho, Oregon, and Washington, with large concentrations of Aldyl-A pipe occurring in the metropolitan centers of Spokane, Washington, Medford, Oregon, and Coeur d’Alene, Idaho. Based on the scope of work and schedule, the GFRP will plan and manage more than 100 Major Capital Projects as follows:

Category	Type	Quantity	Duration	Project Count
Major	Main Pipe	737 miles	20 years	~ 105
Major	STTR	17,769 service tees	5 years (Completed)	~20

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. Assumptions made during the study were as follows:

- Planned replacement of Aldyl-A Mainline pipe costs $357 per three feet in Washington and Idaho and $360 per three feet in Oregon.
- Unplanned replacement of Aldyl-A Mainline pipe costs $5,071 per three-foot section.

- Consequences for a Catastrophic Event, Injury with lost time and injury without lost time are applied per Avista standard practice.

At Avista we forecast Capital Projects/Programs on five-year budget planning cycles which are updated and adjusted annually. In order to provide the most accurate budget forecasts possible it is necessary to draw from the program's most current cost data which is tracked and derived from recently completed projects. The historical spending trend from 2016 through 2021 has been $20M-$23M annually and is reflective of the program's most recent cost experience updates. The requested budget amounts consider Avista's regulatory mandate to complete this program with full contractor complement and to adjust for the mileage that was not completed in 2020* and be in alignment with Distribution Integrity Management Program's (DIMP) prioritization recommendations. This also meets Avista's goal of investing in its infrastructure to achieve optimum life-cycle performance. Inflation of approximately 4% has been planned for by escalating the annual costs.

*There were several impactful events that were outside Avista's control which led to the program deferring $2,535,000 to 2021. Early part of 2020, the COVID-19 pandemic struck the nation and only essential work was able to continue. The NPL union employees went on strike starting on July 6, 2020 and the strike ended on August 26, 2020. Starting on September 8, 2020, in Jackson County Oregon, wildfires blazed in in the Ashland – Alameda Drive area. There were wildfires throughout Oregon (see map below). The wildfires spread due to high winds and the smoke created poor air quality conditions. The outcome of these events in Oregon was the completion of only 2.6 miles of the planned 15.1 miles by NPL.

Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement

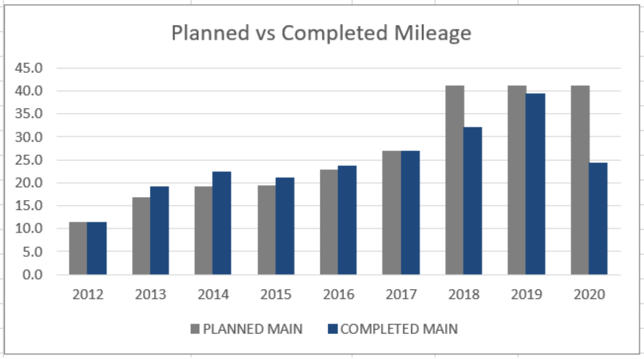
The following tables show the multi-year performance by state for main replacement from 2012 through 2020. Washington is at 97%, Oregon is 73%, and Idaho is 116% of completed main replacement. Overall the Program has completed 92% (difference of 18.8 miles) of the planned main replacement.

	WASHINGTON		
YEAR	**PLANNED MAIN**	**COMPLETED MAIN**	**%**
2012	8.7	8.6	100%
2013	10.7	12.4	117%
2014	9.1	10.7	117%
2015	9.3	10.57	114%
2016	10.54	10.23	97%
2017	14.05	14.62	104%
2018	18.7	15.30	82%
2019	18.7	19.10	102%
2020	18.7	13.23	71%
TOTAL	**118.4**	**114.9**	**97%**

	OREGON		
YEAR	**PLANNED MAIN**	**COMPLETED MAIN**	**%**
2012	2.7	2.7	103%
2013	6.0	6.7	111%
2014	6.5	8.0	123%
2015	6.6	5.9	89%
2016	6.8	7.9	117%
2017	6.9	7.1	103%
2018	14.6	9.23	63%
2019	14.6	7.42	51%
2020	14.6	2.62	18%
TOTAL	**79.3**	**57.6**	**73%**

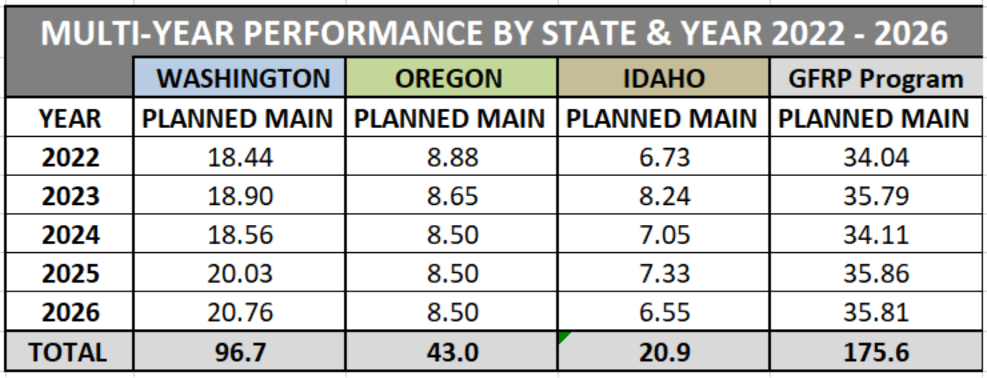
	IDAHO		
YEAR	**PLANNED MAIN**	**COMPLETED MAIN**	**%**
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	3.42	3.65	107%
2015	3.50	4.63	132%
2016	5.40	5.40	100%
2017	5.80	5.20	90%
2018	7.7	7.5	98%
2019	7.7	12.7	165%
2020	7.7	8.5	110%
TOTAL	**41.2**	**47.6**	**116%**

	GFRP Overall		
YEAR	**PLANNED MAIN**	**COMPLETED MAIN**	**%**
2012	11.3	11.4	101%
2013	16.7	19.1	114%
2014	19.0	22.3	117%
2015	19.4	21.1	109%
2016	22.7	23.5	104%
2017	26.8	27.0	101%
2018	41.0	32.1	78%
2019	41.0	39.3	96%
2020	41.0	24.3	59%
TOTAL	**238.9**	**220.1**	**92.1%**



In order to meet maintain optimal production with current personnel levels and account for approximately $1.2M a year for Minor Main/STTRs/and outlying municipal projects, below is the proposed mileage by state from 2022 through 2026.

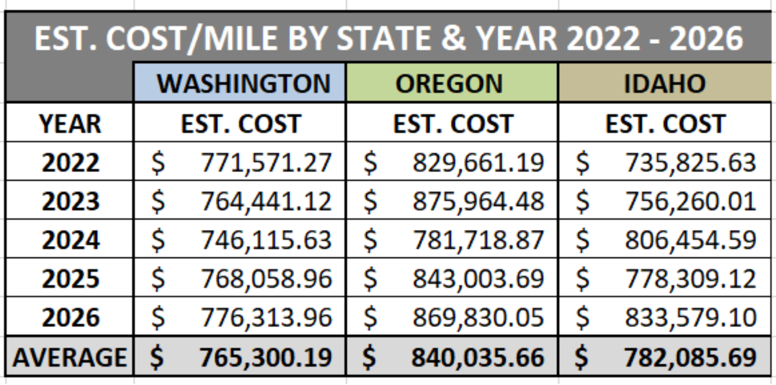
Gas Facility Replacement Program (GFRP)
Aldyl-A Pipe Replacement



MULTI-YEAR PERFORMANCE BY STATE & YEAR 2022 - 2026

	WASHINGTON	OREGON	IDAHO	GFRP Program
YEAR	**PLANNED MAIN**	**PLANNED MAIN**	**PLANNED MAIN**	**PLANNED MAIN**
2022	18.44	8.88	6.73	34.04
2023	18.90	8.65	8.24	35.79
2024	18.56	8.50	7.05	34.11
2025	20.03	8.50	7.33	35.86
2026	20.76	8.50	6.55	35.81
TOTAL	**96.7**	**43.0**	**20.9**	**175.6**

Based on the proposed mileage by state from 2022 through 2026, the estimated cost per mile by state and by year is shown below. Variations of the Cost/Mile are due to project location. For example, if a project requires significant Mobilization, Demobilization, crew travel expense, urban or rural locale, etc.



EST. COST/MILE BY STATE & YEAR 2022 - 2026

	WASHINGTON	OREGON	IDAHO
YEAR	**EST. COST**	**EST. COST**	**EST. COST**
2022	$ 771,571.27	$ 829,661.19	$ 735,825.63
2023	$ 764,441.12	$ 875,964.48	$ 756,260.01
2024	$ 746,115.63	$ 781,718.87	$ 806,454.59
2025	$ 768,058.96	$ 843,003.69	$ 778,309.12
2026	$ 776,313.96	$ 869,830.05	$ 833,579.10
AVERAGE	**$ 765,300.19**	**$ 840,035.66**	**$ 782,085.69**

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Unplanned leak repairs are an O&M cost and are addressed by the local districts. Through this program, O&M expenses are mitigated. 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.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

To establish context, Avista's goal is operate a safe & reliable, and cost-effective gas distribution system. Specifically, as related to these goals, § XI of *"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.

To summarize, the primary alternatives modeled are as follows:

- **Do Nothing**

Pipe Replacement Strategies:

Since the "do nothing" option was not an acceptable or prudent approach, the Company evaluated different periods of time for removal of all Priority Aldyl-A pipe, up to a program horizon of 30 years. Avista assessed the prudence of different approaches based on the forecast of likely natural gas leaks due to failed pipe, as well as the rate impact to customers.

- **Less than 20 Year Pipe Replacement Program**
- **Conduct a 20 Year Pipe Replacement Program (Optimal)**
- **Conduct a 25+ Year Pipe Replacement Program**

Based on the time horizon scenarios modeled, it was determined that the optimum timeframe for removing priority Aldyl-A pipe was the 20 years.

RISKS ASSOCIATED WITH ALTERNATIVES CONSIDERED:

To summarize the primary alternatives and associated risks;

- **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.

- **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.

- **Conduct a 20 Year Pipe Replacement Program:**

  The report proposes and suggests that a Systematic Replacement Program conducted over a 20 year timeline is the optimum timeframe to prudently manage this risk, based on the forecast number of leaks and risks, and the rate impact to our customers.

- **Conduct a 25+ Year Pipe Replacement Program:**

  Lengthening the timeframe to 25 years resulted in more than a doubling of the number of leaks expected when compared to a 20-year horizon. Lengthening the timeline beyond 25 years was found to result in a substantial increase in the number of material failures expected.

As outlined above, Asset Management has identified 20 years as the optimum timeframe to prudently manage this risk. Avista's leadership has adopted this recommendation and has funded and staffed the program to achieve this objective. Furthermore, the three state Commissions that regulate Avista's natural gas operations have thoroughly examined this program in several rates proceedings, and in policy proceedings, and have deemed this approach to be prudent, cost effective, and in the interest of our customers.

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.

Start: January 2012

Expected End: December 2031

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”.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

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.

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

The objective of this investment and structured replacement program is to reduce risk by replacing at risk pipe and by rebuilding Service Tee Transitions. Through rigorous efforts, the GFRP plans and tacks the performance of each project and utilizes Earned Value for cost analysis and for upstream reporting. Furthermore, the GFRP tracks and report Planned vs. Actual quantities by project, year, state jurisdiction, and also reports multi-year cumulative statistics.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Avista’s customers and the general public expect Avista’s natural gas system to operate safely and reliably without incidents. Avista is dedicated to and focused on maintaining a safe and reliable system that shields the public from imprudent risks. The proposed pipe replacement programs have been initiated with the purpose of mitigating the known risks within the natural gas distribution system. Given this context, the Gas Facility Replacement Program’s portfolio of projects could therefore be considered as a customer-related benefit.

The GFRP’s Aldyl-A Pipe Replacement projects touch numerous internal and external stakeholders. A comprehensive list of stakeholders is in the “2019 GFRP Operating Plan & Projects” document.

2.8.2 Identify any related Business Cases

Gas Facility Replacement Program (GFRP) Aldyl-A Pipe Replacement

Business cases have been submitted annually and updated as necessary since 2012, the inception of the Gas Facility Replacement Program.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the GFRP's Program Manager, Cas Operations Contract Construction Manager, Director of Natura Gas, and the Manager of Gas Design & Measurement. This group meets monthly to review program wide Earned Value results, that 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.

3.2 Provide and discuss the governance processes and people that will provide oversight

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 Program Manager.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Gas Facility Replacement Program (GFRP) Advisory Group consists of the GFRP's Program Manager, Cas Operations Contract Construction Manager, Director of Natura Gas, and the Manager of Gas Design & Measurement. This group meets monthly to review program wide Earned Value results, that 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. The monthly documentation tracks the projects and is the primary device for documenting program decision making.

As projects are completed, the Distribution Integrity Management Program (DIMP) Aldyl-A prioritization list is updated annually. As projects are completed, they are removed from the list and new projects are added and evaluated, as necessary.

Annual spend levels and funds change requests to the Capital Planning Group are maintained as documentation of program funding and funding changes throughout the year.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Gas Faility Replacement Program (GFRP)* 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: Karen Cash Date: 7/6/21
Print Name: Karen Cash
Title: GFRP Manager
Role: Business Case Owner

Signature: Mike Faulkenberry Date: 7/6/21
Print Name: Mike Faulkenberry
Title: Natural Gas Director
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Gas HP Pipeline Remediation Program, ER 3057

1 GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requesting Organization/Department	Gas Engineering
Business Case Owner	Jeff Webb, David Smith
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Gas Compliance department is responsible for ensuring Avista is compliant with Federal and State Regulations governing the distribution of natural gas. When a new regulation is brought into effect, the Gas Compliance department will determine if Avista is meeting the requirement or not. If the new requirement is not being met, the Gas Compliance department will notify the appropriate work group and work with them to determine the appropriate path forward to ensure compliance. Gas Engineering is responsible for managing this program.

2 BUSINESS PROBLEM

Current industry Pipeline Safety code requires pipeline operators to have pressure test documentation and material specifications for pipelines distributing natural gas. Avista has some deficiencies in these types of records, but industry regulators (state inspectors) historically have not placed much emphasis on this, specifically for facilities that operate at lower stress levels and therefore at a lesser risk to the public. Avista's history, very similar to that of other utilities, involves pipeline construction during times when the pipeline safety code was not in effect or taken to be that important. Also, Avista has acquired properties from other companies and therefore had no control over their testing practices and record keeping prior to the acquisition. The regulatory climate is now changing and more scrutiny is being placed on having these records.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is actively working on a new rule that is expected to be published in December of 2017 called "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines". When implemented, it will require pipeline operators to have "traceable, verifiable, and complete" Maximum Allowable Operating Pressure (MAOP) records for its transmission facilities. Our understanding of the Rule is that Avista will now need to begin aggressively addressing portions of our system in order to be in compliance. Until the Rule is published, it is not clear yet what the timeframe will be to create a plan and mitigate all deficiencies.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Do nothing / Defer project	$0		
Option 2 – Preferred Solution, Continue to remediate segments of high pressure pipeline.	$3,000,000	2016	2022
Option 3 – Alternative Solution, Reduced funding option: Replace segments of high pressure pipeline.	$1,500,000	2016	2022

Option 1 – Do nothing / Defer project.

If segments of transmission pipeline without traceable, verifiable, and complete MAOP records are not mitigated, Avista will be non-compliant with Federal Pipeline Safety Codes, especially when the Rule mentioned above becomes final. If the work in this program is not completed, Avista will be going against industry guidance and trends. Once the Federal Rules become final, penalties and fines may be imposed for not completing this work.

Option 2 – Preferred Solution, Continue to remediate segments of high pressure pipeline.

As stated above, the proposed Federal Rule will force action to address lack of sufficient MAOP records. Transmission pipelines without traceable, verifiable, and complete MAOP records will be replaced or mitigated within this program. Reasons for this work will include, but are not limited to; incomplete construction and pressure test documents, pipe quality deficiencies from the manufacturing process, and risk reduction in densely populated areas. As a result of completing this option, public and employee safety will be improved by replacing at risk pipe.

Officials and spokesmen from both PHMSA and the American Gas Association (AGA) have stated it is not prudent for operators to wait for the Federal Rule to become finalized before bettering their systems in this category of work. Avista has been in the process of remediating pipelines under this program since 2015. Incidentally, many of these facilities have been in service for over 30 years.

Depending on the final language of the Rule, the annual levels of spending may need to be adjusted in this program. However, as best as Avista is able to tell at this time, what is proposed is the correct pace to complete this Program. The current rate of work is reasonable with Avista's Engineering and construction workforces.

Avista will address replacement or mitigation of its pipelines in the order of highest operating stress and highest levels of record deficiencies. This program will be prioritized in all three of its natural gas operating states and will analyze risks and priorities regardless of jurisdiction. The projects in 2017 will likely all be in Oregon. Replacement projects in 2018 and beyond have not yet been determined.

Option 3 – Alternative Solution, Reduced funding option: Replace segments of high pressure pipeline.

Reduced funding will result in replacing fewer pipeline segments with insufficient MAOP records. This will be at a pace slower than has been accomplished historically and slower than what we feel is the ideal rate as described above. The outcome, should this option be selected, may be pipeline segments being out of compliance with Federal Regulations and a greater amount of backlog to work through once the Rule is published.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas HP Pipeline Remediation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Jeff Webb Date: 4-17-17
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: Date: 4/17/17
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Dave Smith	03/09/2017	Mike Faulkenberry	04/17/2017	Initial version

Template Version: 02/24/2017

Gas Isolated Steel Replacement Program, ER 3007

1 GENERAL INFORMATION

Requested Spend Amount	$1,400,000 – Annual Request
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb / Jenn Massey
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Isolated Steel Program Manager works closely with the Operations Managers to identify the work. The work is then dispatched to Gas Operations to complete. The overall program budget is managed by the Program Manager and Gas Engineering.

2 BUSINESS PROBLEM

The Program objective is to identify and document isolated steel sections of pipeline in Avista's system, including isolated risers, and to replace each riser or pipeline section within a specified timeframe after its identification.

The methodology for identifying sections of isolated steel is a programmatic survey, taking pipeline to soil potential measurements of the subject system. The overall program area is divided into subareas based on Avista's established cathodic protection zones. A three-man team conducts the survey; first obtaining "native" measurements with the CP system de-polarized, and then "on/off" measurements with the system polarized and current interrupters installed. Data is obtained digitally by each survey technician using a Trimble handheld device. The data is tracked and processed using an ESRI ArcGIS platform. Based on survey results, replacement job orders are dispatched and the replacements executed.

Isolated portions of pipe including risers, service pipe and main will be replaced as required to meet the requirements of 49 CFR 192.455 & .457 and in accordance with WUTC Docket PG-100049. This program will be conducted in ID and OR also to assure cathodically isolated steel is identified and replaced as needed through 2024.

Once the isolated sections of steel pipe are identified, projects are created to replace them with new pipe. This new pipe could be either steel or plastic.

Gas Isolated Steel Replacement Program, ER 3007

Management of the cathodic protection (CP) zone will drive the decision between steel and plastic pipe. A Generalized Work Flow is provided in Image 1 below.

Per the WUTC agreement, isolated steel risers are being replaced at a rate of at least 10% per year, starting in 2011, and short sections of isolated steel main are replaced within one year of discovery. Work as previously described is also being completed in ID and OR. Work completed under this program results in a safer gas distribution system.

The Program is currently overseen by a Program Manager. Monthly reporting is used to identify budget targets are met and overall completion in each state. Software has been created to identify time constraints based on severity of potential risk. Action codes are listed in below flowchart.

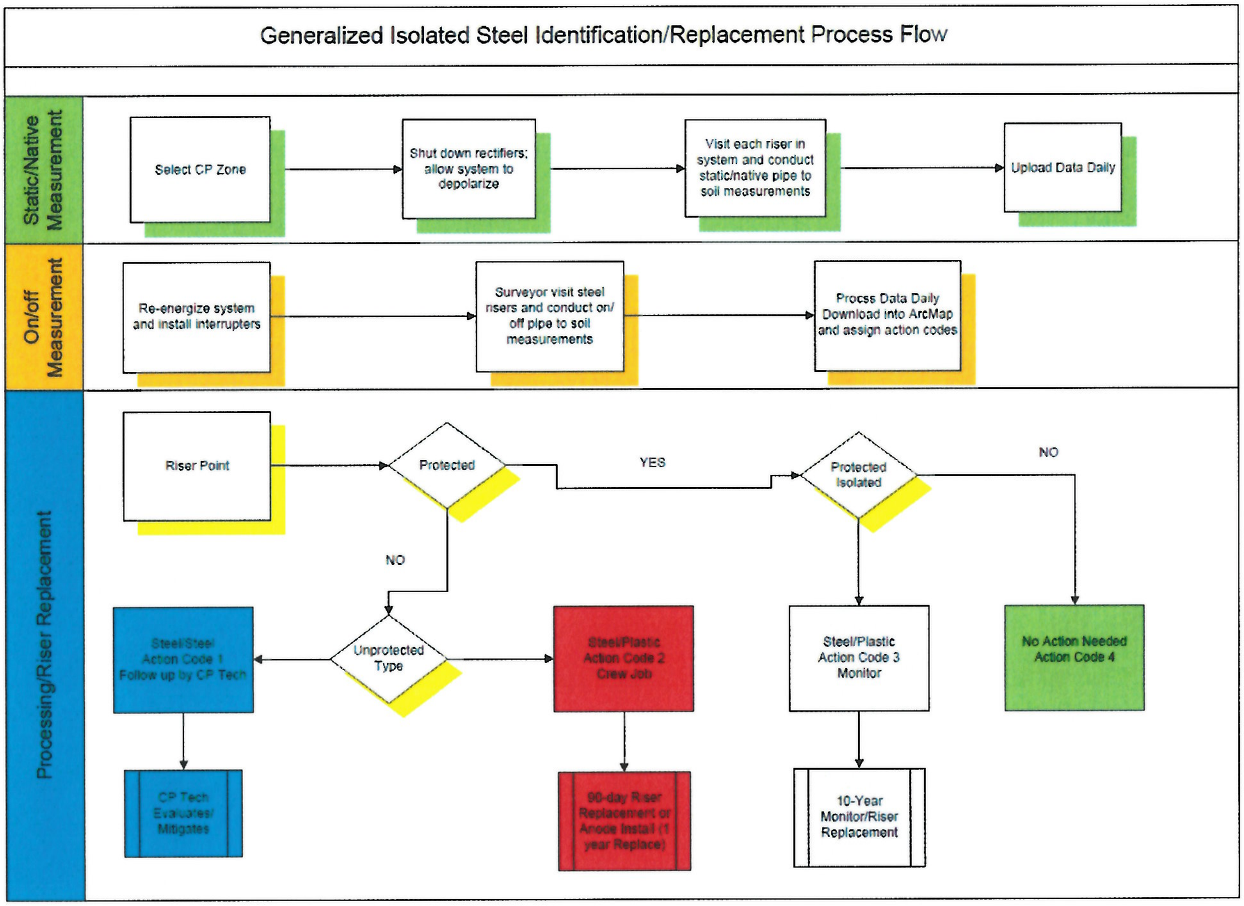


Image 1 – Generalized Work Flow

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$ TBD		
Option 2 – Preferred Solution, Complete the program per the agreement	$2,050,000	2011	11-2021 WA 12-2024 ID and OR

Option 1 – Do nothing

The alternative to completing this program would be to not finish the work within the timeframe mandated by the WUTC. This would be a direct violation of the stipulated agreement between Avista and the WUTC and likely result in financial penalties.

Option 2 – Preferred Solution, Complete the program per agreement as described above

4 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: Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/16/2017			Initial version
1.1	Jeff Webb	04/07/2017			
2.0	Jennifer Massey	02/05/2020	Jeff Webb	2/17/20	Revised for 2020 Oregon GRC filing

Template Version: 02/24/2017

Gas Non-Revenue Program, ER 3005

1 GENERAL INFORMATION

Requested Spend Amount	$9,000,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Program
Driver	Failed Plant & Operations

1.1 Steering Committee or Advisory Group Information

This work is typically unplanned and is initiated by customers or Avista maintenance crews and is managed at the Local District level. Gas Engineering establishes the overall budget based largely 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 this ER that require substantial design efforts such as farm tap retirements, highway or river crossings, and steel pipelines.

2 BUSINESS PROBLEM

The work in this annual program is mostly reactionary, unplanned work and is 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, meter barricades (only in Washington State and only through the year 2020), and farm tap elimination. Each of these work types 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. With the exception of the meter barricade work, the business needs and potential solutions identified impact all gas customers in Avista's service territory.

When shallow facilities are discovered, an appropriate response to the situation is determined by Local District Management. If the response to the situation is capital in nature, then the repair is funded from this program. If the scope of the project is large enough to warrant it, the project will be prioritized and risk ranked against other similar type projects. These types of projects allow Avista to remain in compliance and operate the gas facilities in a safe and reliable manner.

If requested by others (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 is in conflict 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 leaks are found on the gas system, it is sometime advantageous to replace a section of main or service as opposed to just repairing the leak. The Local District looks at the long term fix when possible, not just addressing the immediate concern, and considers what is the right thing to do in these situations. This type of betterment falls under this program.

The need for meter protection can come from a variety of sources: customer, meter reader, atmospheric corrosion inspectors, or from company personnel. Each report is vetted by the Local District to ensure the need is warranted and then the job is scheduled for installation. Installation of meter barricades or break-away fittings on existing meters sets is capital only in Washington State and only through the year 2020.

A single service farm tap (SSFT) installed on a supply 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.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0	N/A	
Option 2 – Preferred Solution, Complete programmatic work as described	$6,000,000	01-2017	12-2017
Option 3 – Alternative Solution, Reduced funding	$3,000,000	01-2017	12-2017

Option 1 – Do nothing

Shallow facilities – Higher likelihood of being damaged and causing a gas leak.

Requested by others & leak repair – To miss the opportunity to better the system while already on-site doing work is shortsighted because we increase the chances of having to be back at the site to remedy other maintenance items at a later date. 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, they must be monitored and re-evaluated on a periodic schedule to ensure they are not becoming a greater hazard to the public.

Meter protection – Not installing meter barricades or break-away fittings is against Federal Rules (CFR 192.353) and presents a significant safety risk to the public, especially if the facilities are damaged.

Farm tap elimination – If 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 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.

Option 2 – Preferred Solution, Complete programmatic work as described

Shallow facilities – Lowering gas mains and services is not required by Federal Rules, but it is prudent. It reduces the chances of damage caused by excavation over and around the gas facilities. This is critical because damage from excavation is the highest risk to our gas facilities. Excavators are expecting gas pipes to be at the depths they are first 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.

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 the time once there is the sensible way to operate. Betterments as described in Section 2 are driven by Company Standards and best practices.

Meter protection – Avista is mandated by Federal Rules to protect above ground facilities from damage. Gas meters located where vehicles are normally parked or driven create a hazard if the meter is not properly protected.

Farm tap elimination – When there are many farm taps located in close proximity to each other and when those stations have reason to be rebuilt, then it makes sense to rebuild just one of them and install distribution main to the other sites to provide a new source of gas. This allows the adjacent 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), inability to perform proper maintenance, and capacity constraints.

The customers benefit from these types of projects by having a safer, well maintained distribution system. Also this is a prudent way to spend resources because many deficiencies at stations can be remedied under just one project. Additionally, the new main might be installed in front of structures without gas service, making it easier to serve them with gas in the future should they choose to change their energy source.

Option 3 – Alternative Solution, Reduced funding

Shallow facilities – Likelihood of being damaged and causing a gas leak if fewer facilities were lowered.

Requested by others & leak repair – *This betterment would happen at a reduced rate, causing workload pressure on the maintenance personnel.* To miss the opportunity to better the system while already on-site doing work is shortsighted because we increase the chances of having to be back at the site to remedy other maintenance items at a later date. 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, they must be monitored and re-evaluated on a periodic schedule to ensure they are not becoming a greater hazard to the public.

Meter protection – Not installing meter protection is against Federal Rules and presents a significant safety risk to the public, especially if the facilities are damaged.

Farm tap elimination - *This optimization would happen at a reduced rate, causing workload pressure on the maintenance personnel.* If 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 may be required to perform this federally mandated 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.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Non-Revenue 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: Date: 2-17-20
Print Name: Jeff Webb
Title: Manager of Gas Engineering
Role: Business Case Owner

Signature: Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Cmt Review

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/16/2017			Initial version
1.1	Jeff Webb	04/05/2017			
2.0	Jeff Webb	2/17/2020			Revised for Oregon 2020 GRC filing

Template Version: 02/24/2017

Gas Overbuilt Pipe Replacement Program, ER 3006

1 GENERAL INFORMATION

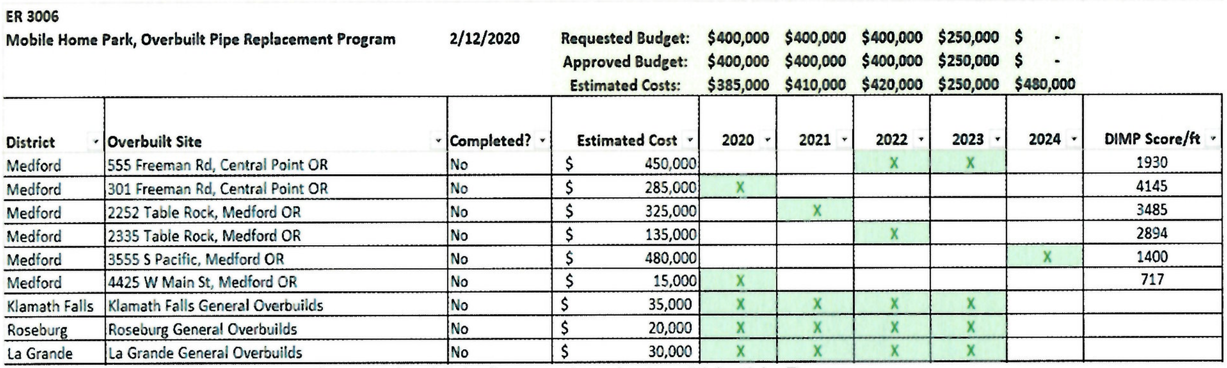
Requested Spend Amount	$400,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb / Seth Samsell
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	Gas Operations & Engineering
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

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.

DIMP has the capability to analyze risk (probability and consequence) associated with various threats to natural gas facilities, including over-built pipe. The DIMP analysis related to overbuilt segments results in an overall risk score for each of the defined segments. The Overbuilt Pipe Program Manager and each of the Gas Operations District Managers utilize DIMP risk scoring to prioritize projects within an approved level of annual program spend. Ideally, overbuilds would all be addressed as they are encountered, however, there is no compliance requirement behind the timing in which overbuilds must be eliminated. Avista has historically managed overbuilt facilities as part of this program and the associated risks along with other risk priorities in the Company. This is the main reason behind the program's historically approved funding levels instead of addressing all known overbuilds as a large, individually funded project. As the number of known overbuilds in the company has decreased, the level of requested and approved funding has decreased as well. The requested spend level has historically been determined based upon mitigating a manageable level of overbuilt facilities across our service territories coupled with any changing costs of construction year to year.

The goal is to manage and prioritize risk associated with overbuilt pipe and complete projects with the highest risk first. Each Operations District is allotted a manageable portion of the approved budget based upon project need. The projects for each district are typically managed locally while the overall program budget is managed by the Program Manager in Gas Engineering. Image 1 below is a list of the current projects within this program.



ER 3006
Mobile Home Park, Overbuilt Pipe Replacement Program **2/12/2020**

Requested Budget:	**$400,000**	**$400,000**	**$400,000**	**$250,000**	**$ -**
Approved Budget:	**$400,000**	**$400,000**	**$400,000**	**$250,000**	**$ -**
Estimated Costs:	**$385,000**	**$410,000**	**$420,000**	**$250,000**	**$480,000**

District	Overbuilt Site	Completed?	Estimated Cost	2020	2021	2022	2023	2024	DIMP Score/ft
Medford	555 Freeman Rd, Central Point OR	No	$ 450,000			X	X		1930
Medford	301 Freeman Rd, Central Point OR	No	$ 285,000	X					4145
Medford	2252 Table Rock, Medford OR	No	$ 325,000		X				3485
Medford	2335 Table Rock, Medford OR	No	$ 135,000			X			2894
Medford	3555 S Pacific, Medford OR	No	$ 480,000					X	1400
Medford	4425 W Main St, Medford OR	No	$ 15,000	X					717
Klamath Falls	Klamath Falls General Overbuilds	No	$ 35,000	X	X	X	X		
Roseburg	Roseburg General Overbuilds	No	$ 20,000	X	X	X	X		
La Grande	La Grande General Overbuilds	No	$ 30,000	X	X	X	X		

Image 1 – List of current projects within this Program

2 BUSINESS PROBLEM

As a natural gas distribution system operator, Avista is required to operate within the minimum safety standards outlined in Part 192 of the Department of Transportation's Code of Federal Regulations (CFR). The CFR defines the laws that all operators must legally comply with in the operation of natural gas distribution systems. There are sections of existing gas piping within Avista's gas distribution system that have experienced encroachment or have been overbuilt by customer constructed improvements (i.e. living structures, sheds, decks, etc.) and were not designed to be installed under these conditions. In these circumstances, it is difficult to operate and maintain these facilities without increased risk or a reduction in overall safety.

Overbuilt facilities restrict company access to the pipe resulting in accessibility issues. If facilities were not designed for overbuilt conditions it can result in the inability to perform certain maintenance activities required by CFR such as meter inspections or leakage survey. Leakage surveys are typically performed by walking directly above the gas facilities while operating leak detection equipment. This maintenance becomes impossible if access to the ground above the facility becomes hindered. Overbuilds not originally designed to be in an overbuilt condition are also a violation of the CFR for an overbuilt facility as they do not meet code requirements for installation within a sealed conduit that can be vented outside of the overlying structure.

Overbuilds present an increased risk to customers due to the threat that gas can get entrapped inside of a structure, which increases the potential for an unsafe atmosphere to develop as well as result in potential ignition which could be catastrophic to life and property. Multiple factors impact risk and the replacement of these facilities, but of primary concern is the increased risk hazard due to a leak. Overbuilds increase operations and maintenance costs as Avista is often required to return to overbuild locations multiple times to attempt and complete leak survey and other maintenance tasks that cannot be completed at the normal scheduled time due to the overbuild.

Addressing overbuilt pipe in mobile home parks is where the highest risk and greatest quantity of overbuilt facilities exist due to the dynamic nature of these facilities. However, overbuilds are not isolated to mobile home parks and the need potentially exists for this program to be utilized in all of Avista's service territories.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing/defer project	$0	N/A	
Option 2 – Preferred Solution/Complete programmatic replacement of overbuilt sections of pipe	$400,000	January	December
Option 3 – Alternate Solution #1/Reduced Funding Option: Complete programmatic replacement of overbuilt sections of pipe at a reduced rate	$200,000	January	December
Option 4 – Alternate Solution #2/Attempt to enforce Avista's easement rights	Unknown	Unknown	Unknown

Option 1 – Do nothing/Defer project

Under this alternative Avista would continue to operate overbuilt facilities without replacement. There is significant risk associated with not remediating these facilities at all and this would be a violation of the Code of Federal Regulations subjecting Avista to potential State and Federal fines associated with operating facilities that are out of compliance. The financial impact of this alternative is very difficult to estimate as penalties for non-compliance are on a case by case basis. Known risks cannot be mitigated without replacement of these facilities or remediation of the overbuild condition. This option is not recommended.

Option 2 – Preferred Solution/Complete programmatic replacement of overbuilt sections of pipe

It is recommended as part of a programmatic approach to identify and replace sections of existing pipes that can no longer be operated safely as they have experienced encroachment or have been overbuilt by customer constructed improvements. Since there is no required compliance timeline for mitigation of overbuilt facilities, completing this type of work as part of a program will allow for Avista to manage the risk overall and prioritize overbuilt facilities based upon those instances with the highest risk to customers as well as operationally. This methodology is also more proactive and is anticipated to have less overall cost impact than by addressing each specific issue as it is encountered or addressing all know overbuilds at one time as an individually funded project. This program aligns with Avista's organizational focus to operate safe and reliable infrastructure for all of our customers in each of our service territories.

The current funding level balances available manpower with other programs administered at the District Offices and allows crews to also work on other compliance and risk reduction type activities. Annual levels of spending may need to be adjusted in this program as the risks in DIMP are reassessed annually.

Option 3 – Alternative Solution #1/Reduced funding option: Complete programmatic replacement of overbuilt sections of pipe at a reduced rate

Another option is to approach the risk associated with overbuilds with reduced funding. Reduced funding will result in replacement of fewer sections of overbuilt piping. The reduced funding alternative would still allow us a benefit by addressing some of the overbuilt facilities with known risk, but at a pace slower than we feel appropriate to address these safety concerns and maintain compliance. The outcome, should this option be selected, would result in the continued operation of facilities known to be out of compliance and which are currently operating with higher risk to customers and operations personnel. Additionally, Avista is often required to return to an overbuild location multiple times in attempt and complete a leak survey or other maintenance tasks that cannot be completed due to the overbuild. This will continue to result in increased operations & maintenance related costs. This option would be a partial employment of both Options 1 and 2 and is not recommended.

Option 4 – Alternative Solution #2/Enforce Avista's easement rights.

A final option to this program is to attempt to enforce Avista's "rights" and try to force the owners, renters, or mobile home parks owners to be liable for these fixes, however the original piping in these locations typically has weak or no easement protection. The ability to prove that the existing customer was responsible for the overbuild can be difficult and sometimes impossible. Avista has experienced in the past that attempts to force customer to pay for these modifications are difficult and often legal fees approach the cost of the work. Legal actions often take an extensive time and resource commitment. Additionally the negative public relations associated with such a philosophy would be very difficult to overcome. This option is not recommended.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Overbuilt Pipe Replacement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

5 VERSION HISTORY

Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Seth Samsell	04/17/2017	Jeff Webb	04/17/2017	Initial version
2.0	Seth Samsell	02/12/2020	Jeff Webb		Revised for 2020 Oregon GRC Filing

Template Version: 02/24/2017

Gas PMC Program, ER 3055

1 GENERAL INFORMATION

Requested Spend Amount	$1,400,000
Requesting Organization/Department	B51 - Gas Engineering
Business Case Owner	Jeff Webb / David Smith
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Gas Engineering, Gas Operations, Gas Meter Shop, and Technical Services work together to administer the Gas Planned Meter Change-out (PMC) program and ensure compliance with the various state rules and tariffs related to gas meter testing. Gas Engineering is ultimately responsible for the PMC plan and annual reports that are submitted to each of the state commissions. Gas Operations and the Gas Meter Shop remove the meters from the customer's premise and install new ones. 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.

2 BUSINESS PROBLEM

Avista is required by 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.

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

Avista's statistical sampling methodology is 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.

Annually the 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 (close to 100% accurate), the sample size (number of meters in that family required to be tested) can be reduced. These analytics help lower costs and also remove meters quickly that are not performing well.

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.

This program assures that our customers' natural gas use is measured accurately in all jurisdictions.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0		
Option 2 – Preferred Solution, Complete programmatic work as described	$1,200,000	January	December

Option 1 – Do nothing/defer project

If this program were not completed fully and accurately, Avista would be out of compliance with state tariffs and could be exposed to fines from the various state utility commissions. Also, the accuracy of measurement of our customers' natural gas usage could not be assured.

Option 2 – Preferred Solution, Complete the programmatic work at the current funding level

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.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas PMC 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: Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Gas PMC Program, ER 3055

Signature: Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/16/2017			Initial Version
1.1	Jeff Webb	04/07/2017			
2.0	David Smith	2/17/2020	Jeff Webb	2/17/20	Revised for 2020 Oregon GRC filing

Template Version: 02/24/2017

Gas Regulator Station Replacement Program, ER 3002

1 GENERAL INFORMATION

Requested Spend Amount	$1,000,000
Requesting Organization/Department	B51 Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Gas Engineering, Gas Operations, and the Gas Meter Shop work together to administer the Regulator Station Replacement Program. Gas Engineering is ultimately responsible for prioritizing the projects and reporting out financial updates to the Capital Budget Group.

A master list of Regulator Stations (pressure reduction stations) and industrial meter sets with reported deficiencies is maintained by Gas Engineering. Gas Operations and the Gas Meter Shop report concerns while performing regular maintenance and these deficiencies are collected on the master list. Annually, subject matter experts from Gas Operations and Engineering review the master list and risk rank the work for the following year. Stations with the highest risk (typically due to multiple different concerns) are prioritized over stations with only minor issues. Prioritizing this work annually with the subject matter experts provides a consistent approach. Through this process, the highest risk projects are selected to be funded.

2 BUSINESS PROBLEM

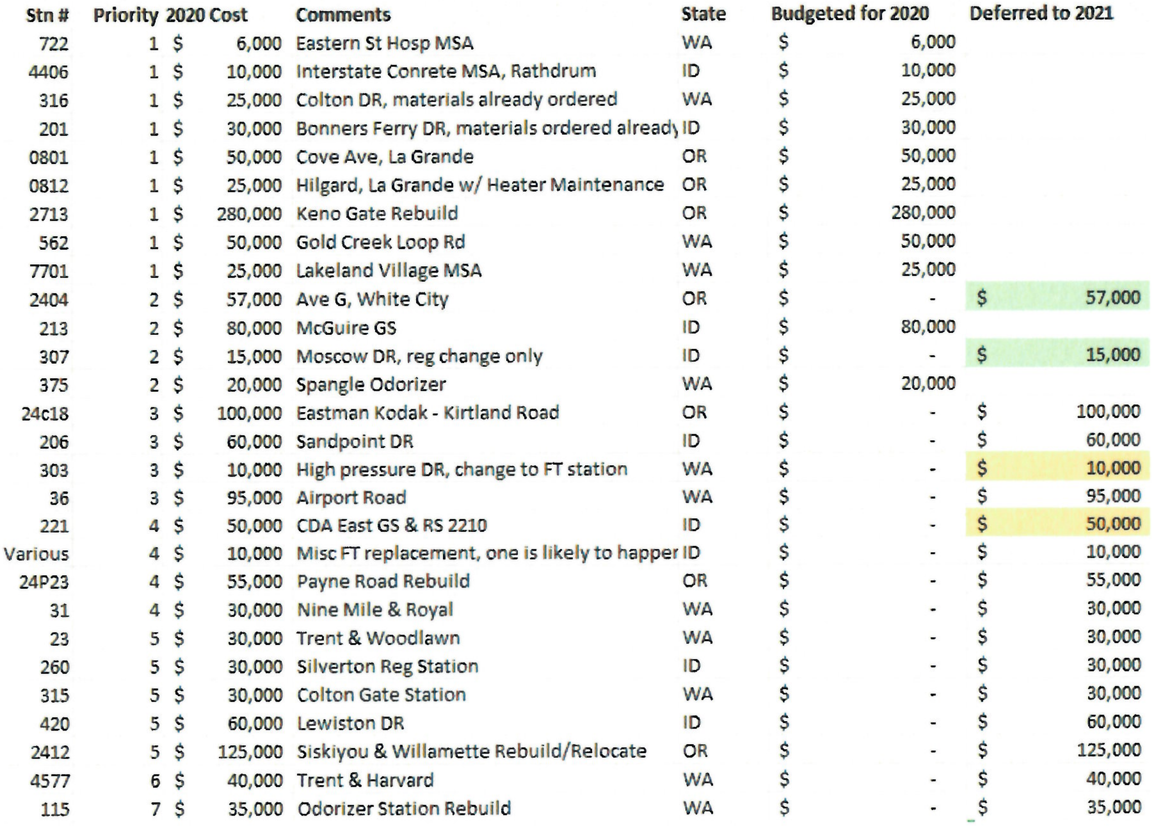
This annual program will replace or upgrade existing at risk Regulator Stations and industrial meter sets that are at the end of their service life to current Avista standards. Additionally, it will address enhancements that will improve system operating performance, enhance safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment.

Another category of work in this program is moving regulator stations located underground in a vault to a more traditional above ground configuration. Stations located in vaults are difficult to maintain because of the limited working room for tools and workers. Additionally, water in the vault can make maintenance more difficult. Regulator Stations in a vault are also a safety concern as they are confined spaces and can trap harmful levels of natural gas should a leak be present.

Gas Regulator Station Replacement Program, ER 3002

These regulator stations require annual maintenance per 49 CFR 192.739, if the equipment at the stations 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 and be exposed to fines from the various state utility commissions.

Our gas customers from all jurisdictions benefit from these types of projects by having a safer, more reliable, well maintained distribution system. Also this is a prudent way to spend resources because many deficiencies at a stations can be remedied under just one project.



Stn #	Priority	2020 Cost	Comments	State	Budgeted for 2020	Deferred to 2021
722	1	$ 6,000	Eastern St Hosp MSA	WA	$ 6,000	
4406	1	$ 10,000	Interstate Conrete MSA, Rathdrum	ID	$ 10,000	
316	1	$ 25,000	Colton DR, materials already ordered	WA	$ 25,000	
201	1	$ 30,000	Bonners Ferry DR, materials ordered already	ID	$ 30,000	
0801	1	$ 50,000	Cove Ave, La Grande	OR	$ 50,000	
0812	1	$ 25,000	Hilgard, La Grande w/ Heater Maintenance	OR	$ 25,000	
2713	1	$ 280,000	Keno Gate Rebuild	OR	$ 280,000	
562	1	$ 50,000	Gold Creek Loop Rd	WA	$ 50,000	
7701	1	$ 25,000	Lakeland Village MSA	WA	$ 25,000	
2404	2	$ 57,000	Ave G, White City	OR	$ -	$ 57,000
213	2	$ 80,000	McGuire GS	ID	$ 80,000	
307	2	$ 15,000	Moscow DR, reg change only	ID	$ -	$ 15,000
375	2	$ 20,000	Spangle Odorizer	WA	$ 20,000	
24c18	3	$ 100,000	Eastman Kodak - Kirtland Road	OR	$ -	$ 100,000
206	3	$ 60,000	Sandpoint DR	ID	$ -	$ 60,000
303	3	$ 10,000	High pressure DR, change to FT station	WA	$ -	$ 10,000
36	3	$ 95,000	Airport Road	WA	$ -	$ 95,000
221	4	$ 50,000	CDA East GS & RS 2210	ID	$ -	$ 50,000
Various	4	$ 10,000	Misc FT replacement, one is likely to happen	ID	$ -	$ 10,000
24P23	4	$ 55,000	Payne Road Rebuild	OR	$ -	$ 55,000
31	4	$ 30,000	Nine Mile & Royal	WA	$ -	$ 30,000
23	5	$ 30,000	Trent & Woodlawn	WA	$ -	$ 30,000
260	5	$ 30,000	Silverton Reg Station	ID	$ -	$ 30,000
315	5	$ 30,000	Colton Gate Station	WA	$ -	$ 30,000
420	5	$ 60,000	Lewiston DR	ID	$ -	$ 60,000
2412	5	$ 125,000	Siskiyou & Willamette Rebuild/Relocate	OR	$ -	$ 125,000
4577	6	$ 40,000	Trent & Harvard	WA	$ -	$ 40,000
115	7	$ 35,000	Odorizer Station Rebuild	WA	$ -	$ 35,000

Image 1 – Prioritized list of rebuild projects

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Do nothing	$0		
Option 2 – Preferred Solution, Replace at risk regulator stations at current funding level	$800,000	January	December
Option 3 – Alternative Solution, Replace regulator stations at a reduced funding level option	$400,000	January	December

Option 1 - Do nothing

The do nothing option will force Avista to operate at risk regulator stations and industrial meter sets in an unsafe, unreliable, and sometimes non-code compliant manner.

Option 2 – Preferred Solution, Replace at risk regulator stations at current funding level

The current level of spending 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. At this pace, the number of stations remediated will outpace the number added each year. 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 well without requiring additional headcount.

Since these stations are a vital link to providing customers with reliable gas, planned work is better than unplanned work. Unplanned work during times of high gas use (normally the winter) can be more difficult to perform and have negative impacts to customers if it fails to operate properly.

Option 3 – Alternative Solution, Reduced funding level option

If this program is funded at a reduced rate, there are two possible ways to accomplish this. One is to replace fewer regulator stations and industrial meter sets. As explained above, there is already a backlog of high risk stations to be replaced, so this option would take an even longer time to get through that backlog while new stations are continually added to the list every year. Secondly, 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. This option is not recommended.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Regulator Station 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: Date: 2-17-20
Print Name: Jeff Webb
Title: Manager of Gas Engineering
Role: Business Case Owner

Signature: Date: 2/17/20

Print Name: Mike Faulkenberry

Title: Director of Natural Gas

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Cmt Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/17/2017			Initial version
1.1	Jeff Webb	04/07/2017			
2.0	Jeff Webb	2/17/2020			Revised for 2020 Oregon GRC filing

Template Version: 03/07/2017

Gas Reinforcement Program, ER 3000

1 GENERAL INFORMATION

Requested Spend Amount	$1,300,000
Requesting Organization/Department	B51 - Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 - Gas Engineering
Category	Program
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Planning department annually runs an analysis (load study) on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve existing Firm customer loads on a design day (Avista is consistent with other utilities in the industry and defines design day as the projected system demand for a "coldest day on record" weather event). These deficient areas are given a priority level based on the severity of the risk associated with insufficient system capacity. The areas with the highest priority are selected for remediation and the project is assigned to Gas Engineering to evaluate options to provide sufficient capacity to meet Firm gas demands on a design day. Options are reviewed with Gas Planning, Gas Operations, and other interested parties. The pros and cons of each option are then reviewed with the Gas Engineering Manager and a preferred alternative is selected to proceed with a funding request. The business needs and potential solutions identified impact all gas customers in Avista's service territory. Spending per jurisdiction changes each year as the intent is to complete the highest risk projects first, regardless of which State it is in.

2 BUSINESS PROBLEM

This annual program will identify and provide for necessary capacity reinforcements to the existing natural gas distribution system in WA, ID, and OR. Avista has an obligation to serve existing Firm gas customers by providing adequate capacity on design day conditions. Sufficient capacity is defined as pressures at or above 15 pounds per square inch (psig) in the distribution system on a design day analysis. Periodic reinforcement of the system is required to reliably serve Firm customers due to increased demand at existing service locations and new customers being added to the system. Execution of this program on an annual basis will ensure the continuation of reliable gas service that is of adequate pressure and capacity.

Typical projects completed under this Business Case may include (but are not limited to) upsizing existing gas mains, looping existing gas mains (bringing in a second source to an area), and installing new regulator stations (pressure reduction stations). When a reinforcement is done by looping a system, there is a secondary benefit of higher reliability to the area. Most of these projects will have a unique project number assigned to them, but the lower cost projects may be completed under the blanket project numbers set up for each district.

Projects that are identified in this program are prioritized by a Gas Planning model, see Image 1 below for a list of high and medium priority projects. The prioritization is based on the computer model that analyzes actual meter usage data from each customer, extrapolates that data to predict a demand load at design temperature conditions, and then analyzes each gas distribution system to determine if reinforcements are necessary. If system capacities are not sufficient the model can also be used to determine the benefits of different types of reinforcement projects by running "what if?" scenarios. Once the projects are identified, they are risk ranked based on the number of customers affected and the temperature levels at which the risks begin.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0		
Option 2 – Preferred Solution, Complete with full funding	$1,000,000	January	December
Option 3 – Alternative Solution, Complete with reduced funding level	$500,000	January	December

Option 1 – Do nothing

Without a Reinforcement Program, Avista does not have sufficient capacity to meet our obligation to serve existing Firm customer load on a design day scenario, and is not able to support future customer growth.

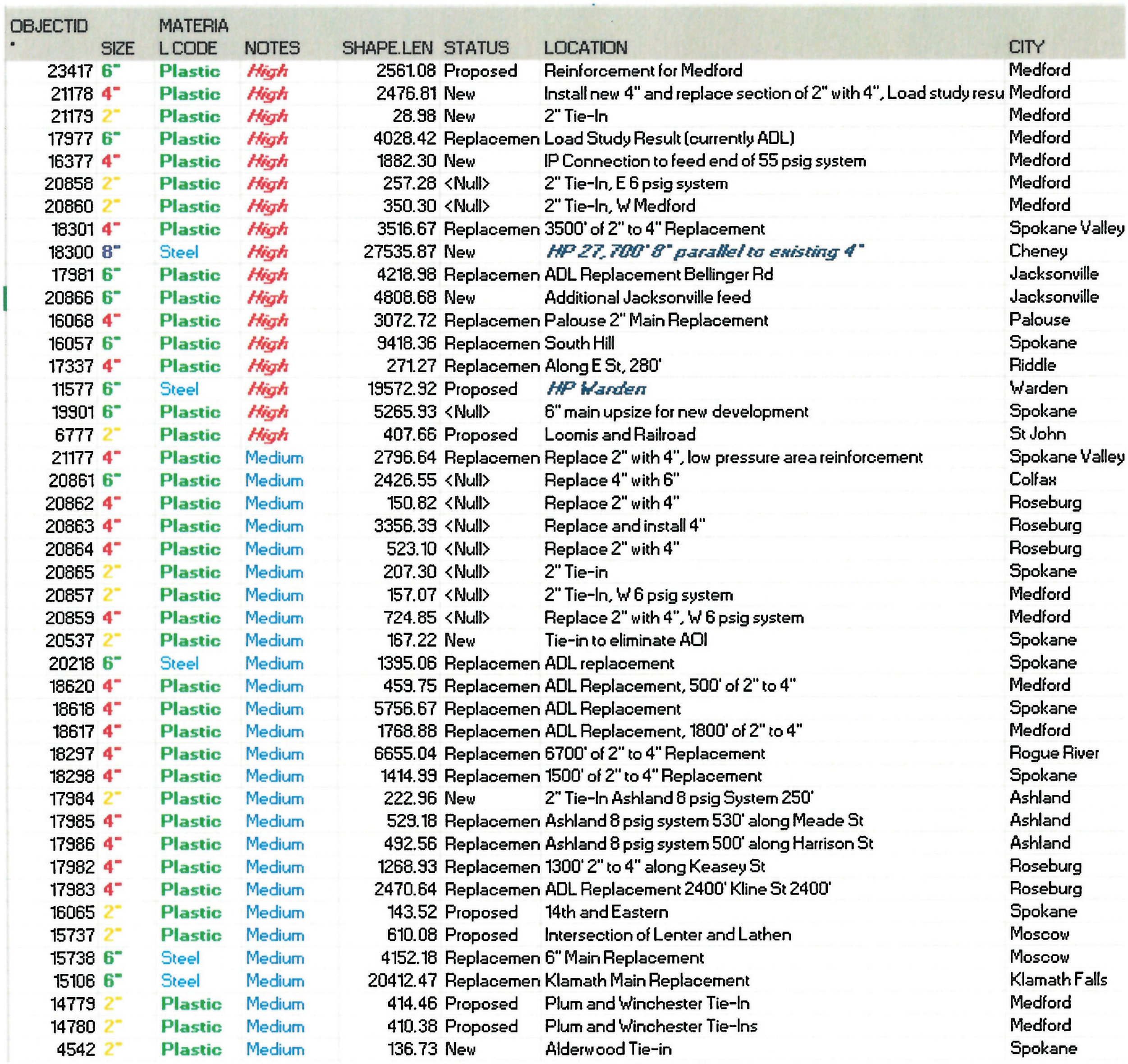
It is important to note that if service is lost during severe cold weather, gas service may not become available again until weather warms and customer demand decreases. Depending on the length of the outage, this can cause severe injury up to and including death to some customers.

Option 2 – Preferred Solution, Complete with full funding

If funding continues as requested, the list will continue to shrink because we'll be able to complete more projects than are coming onto the list. As we work through the backlog of projects, it is anticipated that the funding for this ER will be reduced in approximately six years, but not completely go away as reinforcements will always be needed as new customers are added.

Option 3 – Alternative Solution, Complete with reduced funding level

If funding is reduced, then the timeline to complete the projects and the risks of outages extends proportionally. The more years we keep our system with insufficient capacity, the higher likelihood of have a cold weather event that could cause outages.



OBJECTID *	SIZE	MATERIAL CODE	NOTES	SHAPE.LEN	STATUS	LOCATION	CITY
23417	6"	Plastic	*High*	2561.08	Proposed	Reinforcement for Medford	Medford
21178	4"	Plastic	*High*	2476.81	New	Install new 4" and replace section of 2" with 4", Load study resu	Medford
21179	2"	Plastic	*High*	28.98	New	2" Tie-In	Medford
17977	6"	Plastic	*High*	4028.42	Replacemen	Load Study Result (currently ADL)	Medford
16377	4"	Plastic	*High*	1882.30	New	IP Connection to feed end of 55 psig system	Medford
20858	2"	Plastic	*High*	257.28	<Null>	2" Tie-In, E 6 psig system	Medford
20860	2"	Plastic	*High*	350.30	<Null>	2" Tie-In, W Medford	Medford
18301	4"	Plastic	*High*	3516.67	Replacemen	3500' of 2" to 4" Replacement	Spokane Valley
18300	8"	Steel	*High*	27535.87	New	***HP 27,700' 8" parallel to existing 4"***	Cheney
17981	6"	Plastic	*High*	4218.98	Replacemen	ADL Replacement Bellinger Rd	Jacksonville
20866	6"	Plastic	*High*	4808.68	New	Additional Jacksonville feed	Jacksonville
16068	4"	Plastic	*High*	3072.72	Replacemen	Palouse 2" Main Replacement	Palouse
16057	6"	Plastic	*High*	9418.36	Replacemen	South Hill	Spokane
17337	4"	Plastic	*High*	271.27	Replacemen	Along E St, 280'	Riddle
11577	6"	Steel	*High*	19572.92	Proposed	***HP Warden***	Warden
19901	6"	Plastic	*High*	5265.93	<Null>	6" main upsize for new development	Spokane
6777	2"	Plastic	*High*	407.66	Proposed	Loomis and Railroad	St John
21177	4"	Plastic	Medium	2796.64	Replacemen	Replace 2" with 4", low pressure area reinforcement	Spokane Valley
20861	6"	Plastic	Medium	2426.55	<Null>	Replace 4" with 6"	Colfax
20862	4"	Plastic	Medium	150.82	<Null>	Replace 2" with 4"	Roseburg
20863	4"	Plastic	Medium	3356.39	<Null>	Replace and install 4"	Roseburg
20864	4"	Plastic	Medium	523.10	<Null>	Replace 2" with 4"	Roseburg
20865	2"	Plastic	Medium	207.30	<Null>	2" Tie-in	Spokane
20857	2"	Plastic	Medium	157.07	<Null>	2" Tie-In, W 6 psig system	Medford
20859	4"	Plastic	Medium	724.85	<Null>	Replace 2" with 4", W 6 psig system	Medford
20537	2"	Plastic	Medium	167.22	New	Tie-in to eliminate AOI	Spokane
20218	6"	Steel	Medium	1395.06	Replacemen	ADL replacement	Spokane
18620	4"	Plastic	Medium	459.75	Replacemen	ADL Replacement, 500' of 2" to 4"	Medford
18618	4"	Plastic	Medium	5756.67	Replacemen	ADL Replacement	Spokane
18617	4"	Plastic	Medium	1768.88	Replacemen	ADL Replacement, 1800' of 2" to 4"	Medford
18297	4"	Plastic	Medium	6655.04	Replacemen	6700' of 2" to 4" Replacement	Rogue River
18298	4"	Plastic	Medium	1414.99	Replacemen	1500' of 2" to 4" Replacement	Spokane
17984	2"	Plastic	Medium	222.96	New	2" Tie-In Ashland 8 psig System 250'	Ashland
17985	4"	Plastic	Medium	529.18	Replacemen	Ashland 8 psig system 530' along Meade St	Ashland
17986	4"	Plastic	Medium	492.56	Replacemen	Ashland 8 psig system 500' along Harrison St	Ashland
17982	4"	Plastic	Medium	1268.93	Replacemen	1300' 2" to 4" along Keasey St	Roseburg
17983	4"	Plastic	Medium	2470.64	Replacemen	ADL Replacement 2400' Kline St 2400'	Roseburg
16065	2"	Plastic	Medium	143.52	Proposed	14th and Eastern	Spokane
15737	2"	Plastic	Medium	610.08	Proposed	Intersection of Lenter and Lathen	Moscow
15738	6"	Steel	Medium	4152.18	Replacemen	6" Main Replacement	Moscow
15106	6"	Steel	Medium	20412.47	Replacemen	Klamath Main Replacement	Klamath Falls
14779	2"	Plastic	Medium	414.46	Proposed	Plum and Winchester Tie-In	Medford
14780	2"	Plastic	Medium	410.38	Proposed	Plum and Winchester Tie-Ins	Medford
4542	2"	Plastic	Medium	136.73	New	Alderwood Tie-in	Spokane

Image 1 – Prioritized list of reinforcements

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Reinforcement 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: Date: 2-17-20

Print Name: Jeff Webb

Title: Manager Gas Engineering

Role: Business Case Owner

Signature: Date: 2/17/20

Print Name: Mike Faulkenberry

Title: Director of Natural Gas

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Cmt Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/17/2017			Initial version
1.1	Jeff Webb	04/06/2017			
2.0	Jeff Webb	2/17/2020			Revised for 2020 OR GRC Filing

Template Version: 03/07/2017

Gas Replacement Street and Highway Program, ER 3003

1 GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Program
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Gas Operations manages this category of work. The work is generated by the various municipalities that Avista has franchise agreements in. The overall program budget is managed by Gas Engineering.

2 BUSINESS PROBLEM

It is very difficult to forecast year-to-year what the cost in this category will be. Virtually all of Avista's pipelines are located in public utility easements (PUEs) which are controlled by local jurisdictional franchise agreements. Avista is mandated under these agreements to relocate its facilities, when local jurisdictional projects necessitate. Often these come without significant lead time by the local jurisdictions. It is often the case that meetings are called in the Spring to notify franchisees (natural gas, electric, cable, phone etc.) that they will need to relocate their facilities. This does not enable ideal planning and often may cause Avista to spend unbudgeted funds and do so in a manner that is not of the utmost efficiency.

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 gas facilities are required, then Avista must 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.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$ TBD		
Option 2 – Preferred Solution, Complete	$3,000,000	January	December

replacements as necessary			

Option 1 – Do nothing

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 be in conflict with 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.

Option 2 – Preferred Solution, Complete the replacements as necessary

By completing the projects as requested, then Avista meets the obligations under its franchise agreements, remains in good standing with the municipalities, and avoids financial penalties.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Replacement Street and Highway 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: Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Cmt Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/17/2017			Initial version
1.1	Jeff Webb	04/07/2017			
2.0	Jeff Webb	2/17/2020			Revised for 2020 Oregon GRC filing

Template Version: 03/07/2017

Gas Telemetry Program, ER 3117

1 GENERAL INFORMATION

Requested Spend Amount	$200,000
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb / Dave Moeller
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 Gas Engineering
Category	Program
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Measurement Engineer works with the Gas Telemetry Technicians, Gas Planning, Gas Engineering, Metering Automation, Gas Operations, Gas Control Room, Supervisory Control and Data Acquisition (SCADA), and Gas Supply groups to determine possible projects or locations for new telemetry sites or upgrades of existing equipment. The Gas Engineering Manager reviews the recommendations from the Gas Measurement Engineer and approves the specific projects within this program. A five year plan is also created by the Gas Measurement Engineer and approved by the Gas Engineering Manager.

2 BUSINESS PROBLEM

Avista's commitment to safety and reliability dictates that we monitor our gas system to ensure safe and reliable operation and accurate metering and accounting for gas purchased and sold. This includes compliance with Federal and State Gas Control Room Management Rules.

Gas Telemetry provides data that is used pro-actively for early detection of abnormal operating conditions before they become major problems which may affect safety or gas delivery. Additionally, telemetry is used to remotely monitor system pressures, volumes, and flows from areas of special interest such as gate stations which supply gas to Avista's system, gas transportation customers, regulator stations which reduce and regulate pressure, selected large industrial customers, end of line pressures, and per CFR192.741 requirements, pipeline systems with more than one source of gas.

Alarm set points in the field instruments such as flow computers, electronic volume correctors, and electronic pressure monitors to alert the Gas Control Room of abnormal operating conditions such as low or high pressure, high flow, high or low gas temperatures indicating problems with gas heaters at gate stations, and transducer failures. Communication with the instruments is via cellular modems or telephone lines.

An important example is the detection of degraded pressure regulator performance resulting in high or low pressures caused by dithiazine deposits in our regulators. In 2019 this occurred over 100 times at sites with telemetry. This is a mix of early detection by pro-active human analysis by evaluating pressure trends recorded in PI and pressure alarms received in SCADA. More pressure monitoring with telemetry is planned at additional stations relating to this issue. By proactively monitoring these sights, Avista can dispatch field personnel during normal business hours instead of waiting to respond to an alarm that may happen at any time of the day.

Additionally, data from these telemetry sites is used to validate the system modeling tool that Gas Planning creates every year. Since the data collected is electronic, it can be represented graphically to quickly analyze any anomalies. In addition to permanent equipment, around 50 temporary, portable pressure recorders with cellular modems are connected to piping in areas of interest where permanent equipment has not yet been installed, will not be needed, or is not practical.

The Gas Supply department benefits from these projects by having metering data from Gate Stations that is calculated and transmitted independently of the interstate pipeline's metering and billing info based on our instrument's measuring pressure and temperature and calculating gas volume based on pulses from the Pipelines meter. This aids in finding calculation or metering errors at the Gate Stations. Billing errors left unfound can create problems that lead to extra work and manual corrections between Avista and the interstate pipelines. This also provides data for cases when the Pipelines' do not have data on their side.

The customers and general public benefit from Avista having good "visibility" to the gas transmission and distribution system. This allows for a quicker response and better decision making from the Gas Control Room and Gas Operations when an abnormal or emergency situation occurs.

For example, we are quickly notified electronically of low pressure situations that if not addressed in a timely manner could result in significant loss of gas service to our customers. We are also notified of high pressures which could be hazardous or result in blowing gas such as when a pressure relief valve opens to limit the pressure in our piping.

If there were no telemetry, Avista would have to wait for customers to call in after they've lost gas service which at that point would have a significant impact to our customers and require substantial time and manpower to restore service. Costs could range from a few thousand dollars to a million dollars. In the case of high pressure and relief valve venting at one of our stations, we could be releasing gas to atmosphere for extended periods until a passerby notified us of the noise or a gas odor.

Avista strives to replace equipment that has reached the end of its reasonable service life with new equipment that makes use of current technology before reliability is significantly degraded or maintenance costs are excessive. We also review existing installations for opportunities to improve reliability, acquire more data, or more efficient ways of collecting the data.

Enhancing the gas telemetry system increases situational awareness and visibility of the gas system to help analyze operational concerns and monitor cold weather performance by the Gas Control Room Operators, Gas Operations, and Gas Engineering and Planning.

This program will continue the installations and upgrades of gas telemetry throughout Avista's gas service territory in Oregon, Washington, and Idaho. Over the last several years, costs have averaged approximately 45% spent in OR, 35% in WA, and 20% in ID.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0	N/A	
Option 2 – Preferred Solution, Replace/install telemetry at the current funding level	$200,000	January	December

Option 1 – Do nothing

To make no further additions or upgrades to Avista's gas telemetry system would result in less capability to see "real time" performance of the gas system, inability to see operational abnormalities in a timely fashion, subject our customers to increased chances of low or high pressure situations and their related safety risks, and the reliability of the existing system would decline due to equipment failures. More equipment would reach end of life and maintenance costs would increase.

Option 2 – Preferred Solution, Replace/install telemetry at the current funding level

At the current funding level, Avista adds approximately 10 new sites and upgrades approximately 15 sites per year. Costs per site typically range from $5,000 for a simple upgrade to $50,000 for adding telemetry to a gate station.

The cost of this option represents a minimal amount and may need to be increased in future years depending on equipment failures. Some years more work is required and costs may be shared with other departments such as in 2019 when Verizon Wireless announced it was turning off 3G cellular service starting at the beginning of 2020 so we replaced approximately 170 3G cellular modems with 4G modems.

Based on current failure rates and funding, on the average this funding level has allowed upgrades as instrumentation fails and allows for modest enhancements to the system. This allows the high priority sites to be addressed as the need arises or equipment fails.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Telemetry Program (ER3117) 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: Date: 2-17-20
Print Name: Jeff Webb
Title: Manager Gas Engineering
Role: Business Case Owner

Signature: Date: 2/17/20
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Cmt Review

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	03/14/2017			Initial version
1.1	Jeff Webb	04/07/2017			
2.0	Dave Moeller	2/17/2020	Jeff Webb	2/17/2020	Revised for 2020 Oregon GRC filing

Template Version: 02/24/2017

Central 24 HR Operations Facility

EXECUTIVE SUMMARY

For decades, several of Avista's most critical operations have been located on the 4th floor of Avista's General Office Building on the Mission Campus. This includes departments such as System Operations, SCADA, Electric and Gas Dispatch, Network Operations, Security Operations, and 24 Hour Call Center Reps. Meanwhile, our Generation Control Center, in their leased space at Steam Plant Square in downtown Spokane, has also provided critical operations since the 1990s. Over time, as each of these departments experience new growth due to ever changing utility requirements and/or initiatives, capacity has been reached in available square footage, necessitating an expansion of their spaces. In addition, as best practices for critical utility functions come out within the industry, certain problems related to the safety and security of these functions arise, which may in turn lead to a catastrophic reliability of services in a serious event. Certain technology limitations, maximizing effectiveness during storm responses, and high O&M expenses are also problems to be addressed in this business case.

The recommended solution, at the time of this writing (July 2020), is to build a new, secure, and isolated 24 Hour Operation Facility at the Jack Stewart Training Center, currently owned by Avista. There are several other solutions currently being determined by an Advisory Group, which may change the recommended solution at a later date. The recommended solution, again at the time of this writing, is estimated to cost $24,000,000 spread over three years. Since this facility will support Avista functions in all service territories, the jurisdiction is slated to be Common Direct – Allocated All. Once the business case is complete, customers can expect a continuation of reliable critical functions to last well into the future due to the improvements, with greater efficiencies and capabilities.

The three year timeline will provide ample opportunity to design and execute the recommended solution, at a pace that will allow many details to be unearthed and addressed properly. With a project of this magnititude, many stakeholders and groups will be affected during the design phase in the first year of the project, with construction/exectution occurring over the last two years. It is recommended to proceed with this business case as soon as possible to avoid any potential reliability risks that may occur in the future.

VERSION HISTORY

Version	Author	Description	Date	Notes
0.0	*Vance Ruppert*	*Executive Summary Only*	*7/10/2020*	
1.0	*Vance Ruppert*	*BCJN Update to new template, revisions*	*7/31/2020*	

Central 24 HR Operations Facility

GENERAL INFORMATION

Requested Spend Amount	$24,000,000
Requested Spend Time Period	3 years
Requesting Organization/Department	Facilities – H07
Business Case Owner | Sponsor	Eric Bowles | Dan Johnson
Sponsor Organization/Department	Shared Services
Phase	Initiation
Category	Project
Driver	Performance & Capacity

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Avista's 24 Hour operations consist of System Operations, SCADA, Electric Dispatch, Gas Control and Credit Dispatch, 24 Hour Customer Service, Network Operations, Security Operations, Generation Control Center, and Real Time. Currently, most of these departments are located on the 4th floor of Avista's General Office Building (GOB) on the Mission Campus. The Generation Control Center is located in downtown Spokane in a rented space at the Seehorn Building, and Real Time is on the 5th floor of Avista's GOB. Within the departments there are roles that are standard business hours, and roles that require 24 HR shift staffing. The standard business hours support staff are critical to their departments' function and would be preferred to be in the same space or adjacent to the 24 Operations Center, but not required.

There are several current problems that are meant to be addressed by this Business Case. The primary business problem is space limitations within each group. Currently, all 24 Hour Operations spaces are too small for their existing business needs. Compounding the issue is that several of the departments have plans for growth within the next 5 years. The 24 Hour shift jobs all have unique and specific tasks that require "operator style" workstations that are larger and more complex than the Avista standard 6x9 office cubicles (usually the operator style workstations require 80-100 sq. ft. of space). The support staff, even though 6x9 cubicles are sufficient, are increasing in count as well over the next 5 years. Due to this, their current allocated square footages, for all departments, cannot be reconfigured or remodeled to accommodate these future needs.

The second business problem being addressed is technology limitations and upgrades. For example, the existing System Operations' distribution wall map is in the same location as it was in the original construction of the GOB in the mid-1950's. Several upgrades over time have occurred, but it is still lacking visual displays, readouts, or technology features that are commonplace in peer utility system operations centers. Another example is that a single operator desk commonly requires a minimum of 12 (possibly more) dedicated network drops to run all the systems required. It is becoming increasingly difficult and expensive to retrofit technology in all of these spaces to add desks or enhance systems. Many of the current operator desks also require anywhere from 8 to 12 computer monitors as well, which limit operator views to their shared department displays, and require additional network drop increases.

Lastly, many of these departments use partial areas of the 4th and 5th floor of the GOB. Facilities in turn is required to run all HVAC and electrical functions on these floors at all times, even though the majority of the floors are unoccupied during off hours. Combining these departments into a common space could potentially help save O&M expenses and maintenance incurred due to a 24 hour run time. In addition, if the GCC were moved to a non-leased facility, considerable O&M savings could be realized.

1.2 Discuss the major drivers of the business case and the benefits to the customer

The major driver of this business case is Performance & Capacity, with aspects of Service Quality & Reliability and Asset Condition. Our 24 Hour Operations needs to be at the forefront of performance and reliability, especially during an outage, emergency, or customer event. It is imperative that these critical functions remain operational and maximize effectiveness for the benefits of all of our customers, at all times. Due to our current space constraints, the asset conditions of all of these departments becomes another minor driver of this business case.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

With the business problems described above, it is going to be impossible to accommodate the future needs of these departments without a new solution. Within a year or two, we possibly risk only having a very expensive solution to execute important company initiatives such as the Energy Imbalance Market. In general, the longer this Business Case is not implemented, the greater the chance the risk of any of the business problems could occur.

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.

At this time, the only measure that can be used is to design a solution that provides room for growth, expands technology requirements, and adheres to safety and security best practices to protect these critical operations at Avista. Some of these solutions would include items such as:

1) Room for employee or operator desk growth
2) Combine the departments into a common facility independent of non-critical departments
3) Maximize effectiveness during storm responses or emergency events
4) Provide required technology upgrades and ability to retrofit easily
5) Provide dedicated facilities to mitigate risk of pandemics
6) Increase current security controls and points of access

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

24 Hour Operations Requirements List – July 2020 Update of a July 2018 document. Available on request, please contact Facilities / Vance Ruppert.

2005 Study of possible Backup Control Center for 24 Hour Operations. Available on request, please contact Facilities / Vance Ruppert.

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.

Even though asset replacement is a minor business case driver, several images of current conditions and space studies are available upon request. Please contact Facilities / Vance Ruppert.

Option	Capital Cost	Start	Complete
Recommended Option: *Relocate the Training Center from Jack Stewart to another location in Spokane and use the JSTC site for a new 24 Hour secured location.*	*$24M* *(24 Hr Bldg Only – Does not include JSTC relocation)*	*01/2021*	*09/2023*
Alternate 1: *Build a new building on a site currently owned by Avista. (Probably Boulder site / substation, or Irvine property)*	*$24M*	*01/2021*	*09/2023*
Alternate 2: *Remove all non-24 Hour Operations from the 4th floor of the GOB, and expand the current 24-Hour Operation footprint to encompass the whole floor*	*$14.4M*	*01/2021*	*03/2023*
Alternate 3: *Build new office square footage for 24-Hour Operations on top of the existing Service Building*	*$16M*	*01/2021*	*06/2023*
Alternate 4: *Purchase new land and build a building on the outskirts of Spokane*	*$26.2M*	*01/2021*	*12/2023*

Note: See Appendix A for further cost estimate breakdowns.

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The main intent of this project is to mitigate the business problems as described in Section 1.1. As of July 2020, the intent is provide beneficial solutions as described in Section 1.4. There is no tangible way to measure customer benefits, other than using an increased reliability metric and response time metric, especially during outages or emergency events.

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). Include any known or estimated reductions to O&M as a result of this investment.

The requested capital cost amount of $24M will be broken out between 3 years. In 2021, $4M will be requested to design, permit, and competitively bid the project to a general contractor. In addition, some monies will be used to begin construction with the winning general contractor. Due to the complexity of this project, it is expected the construction costs, soft costs, and ET costs will spend $12M in 2022 and $8M in 2023.

As of this writing (July 2020), the recommended solution is estimated to be 38,000 – 50,000 square feet, and the resulting design will address the business problems described above. It is unknown if all of the departments outlined above will be included in the final building layout, but that is the initial intent.

By relocating the 24 HR Shift Operations from the 4th floor to an off-site location, there would be multiple O&M budget benefits and adjustments, including:

- There would be an annual savings for pump and fan energy by not running HVAC and electrical for 24 hours a day on the 4th floor of the GOB of approximately $29,000 a year.
- There would be savings for switching from the main well to the secondary well for cooling in the amount of $7,651.18 per year.
- Merging the GCC into the new 24 hour building would save in ongoing annual lease expenses of over $120,000 a year (Includes a 10% lease increase after Jan 2020).
- There would be an approximate O&M increase of approximately $60,000 yearly due to new contracts with some of our vendors including janitorial, landscaping, asphalt maintenance, and snow removal. It is also expected that Facilities maintenance staff will need to perform work orders as needed on the new facility. Please note, this cost might drop to $40K yearly if Option 4 or 5 are implemented, due to proximity of the solution to our current vendors and maintenance staff and the Mission Campus.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

All of the departments listed in Section 1.1 will be greatly impacted if this business case is implemented. Many of their primary functions will not change, but the method in HOW they perform those primary functions will change greatly. Space configurations, technology improvements, safety and security improvements, etc. will greatly change their day-to-day operations, but it is expected that all of these improvements will provide many benefits to their current processes.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

All of the options listed in Section 2 above are alternatives to the primary preferred Recommended Option. However, the alternatives may not provide a full solution to the business problem. As of July 2020, the director level “second” Advisory Group as described in Section 3.1 (B) are considering all the risks for each alternatives (shown below), and may come to a different conclusion other than the Recommended Option.

In general, risks (good and bad) of each option are present. Below is a list of the main risks that are currently being considered/asked when selecting any of the alternatives. Some will answer yes, some no. Please note this is not intended to be exhaustive.

Does the solution have the space for all functions to be located together?

Does the solution have the space for future growth?

Does the solution have a site where infrastructure utility requirements can be met?

Does the solution have a site that meets compliance requirements?

Does the solution provide enhanced safety and security from populated areas, natural disasters, terrorism, etc.?

Does the solution have the ability to isolate the 24 Hour Operations groups?

Does the solution support broader company strategies?

Does the solution provide cost prudency to solve the business problems the best, even if it is higher 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. spend, and transfers to plant by year.

This business case is considered a project, as it is not intended to be an ongoing project beyond 2023. The major milestones and timeline of the project is estimated to be the following:

Complete Design Drawings: August 2021

Bidding / permits complete, General Contractor (GC) selection: September 2021

GC begin construction: September 2021

GC complete construction, receive Certificate of Occupancy: March 2023

Install Furniture, Fixtures, and Equipment: May 2023

Testing of all systems: July 2023

Move into new facility: September 2023

The project is expected to complete and become used and useful in March 2023, once the GC achieves Certificate of Occupancy from the Jurisdiction Having Authority. It is expected that around $20M will transfer to plant at that time, with the remaining $4M to TTP over the course of the next 6 months, with the project hard close anticpated in Q4 of 2023.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The major reason to perform this project is to align with Avista’s stragetic vision of customer performance and reliability. It is also beneficial to new initiatives such as the Energy Imbalance Market, who will be primarily housed within this new 24 Hour Operations Center.

A secondary reason, if an off-site solution is selected, is to recoup office space at the Mission Campus to aid in net employee growth that Avista has seen throughout the last 10 years. This might provide relief from having to possibly build new office space, or lease office space off site.

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

Hopefully the business problems described earlier makes a strong case that this investment makes sense, as to avoid significant operational, reliability, and performance risks. As the project progresses, the scope and budget will be re-baselined as required. and hopefully the project can come in possibly under budget and ahead of schedule. Full oversight of the scope and budget will be provided to the Facilities Steering Committee (see Section 3.1 (A)) for their review and evaluation as described in Section 3.2 and 3.3.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Major customers/stakeholders:

Transmission Operations (Mike Magruder)
System Operations (Rip Divis, Brad Calbick)
Electric Dispatch (Reuben Arts)
SCADA (Craig Figart)
Gas Control and Credit Dispath (Mike Faulkenberry, Tim Mair, Carrie Mourin)
24 Hour Customer Service (Andrea Pike, TBD)
Network Operations (Mike Busby)
Security Operations (Clay Storey, Scott Baker)
Generation Control Center (Andy Vickers, Bob Weisbeck, Ryan Bean)
Facilities (Dan Johnson, Eric Bowles, Robert Johnson, Vance Ruppert)
Enterprise Technology (Jim Corder, Elizabeth Arnold)

Minor customers/stakeholders:

Real Time (TBD)

2.8.2 Identify any related Business Cases

Several previous interations of this business case were submitted to the Capital Planning Group in 2018 and 2019. This current version might also be possibly be superceded by a later version.

If Option 1 (preferred option) is selected, there is another business case called “Corporate and Craft Training” which is meant to build a new training center and move it from its current location at Jack Stewart. This business case would need to proceed in order to select Option 1.

3.1 Steering Committee or Advisory Group Information

A. The Facilities Steering Committee (SteerCo) (as of July 2020) shall consist of the following: Dan Johnson, Mike Faulkenberry, Andy Vickers, David Howell, Jim Corder, Lauren Pendergraft, and Bruce Howard.

B. The first Advisory Group (as of July 2018) that created and assisted in shaping the 2018 version of this Business Case consisted of the following stakeholders:

- Facilities: Anna Scarlett, Eric Bowles, Vance Ruppert, Lindsay Miller, and Annie Lundy
- Garth Brandon, Chief Systems Operator
- Clay Storey, Sr Manager Security Engineering and Ops
- Reuben Arts, Chief Distribution Dispatcher
- Brad Calbick, Manager Energy Management Systems
- Carrie Mourin, Manager Gas Control and Service Dispatch
- Mike Busby, Manager IT Operations
- Bob Weisbeck, Manager Hydro Operations and Maintenance

Subsequently in July 2020, a second Advisory Group was formed that consisted of director-level employees including: Dan Johnson, Mike Magruder, Mike Faulkenberry, Andy Vickers, Jim Corder, and Clay Storey (promoted to Director of IT & Security Management).

In addition, the employees indicated above in the 2018 Advisory Group were re-interviewed to refine the current 2020 version of this Business Case. Several new employees were interviewed and added to the list in this second 2020 Advisory Group, including:

- Rip Divis, Chief Systems Operator (retirement replacement for Garth Brandon)
- Tim Mair, Manager Gas Control and Service Dispatch (development opportunity)
- Craig Figart, Manager SCADA/EMS
- Ryan Bean, Manager Spokane River Hydro

3.2 Provide and discuss the governance processes and people that will provide oversight

The project shall use certain Project Management Professional (PMP) guidelines and procedures during the course of this project.

A Project Execution Plan, consisting of the documents below, will be drafted and approved by the SteerCo described in Section 3.1 (A).

- Project Charter, Change Management Plan, Communication Management Plan, Cost Management Plan, Procurement Management Plan, Project Team Management Plan, Risk Management Plan and Risk Register, Schedule Management Plan, Scope Management Plan, and Project Execution Approval Form.

Each month, the project manager will provide the following information either at the scheduled SteerCo meeting, or via email.

- Approved Yearly Budget, Accrued Yearly to Date, Year Estimate at Complete, Year Variance at Complete, Approved Lifetime Budget, Accrued Life to Date, Lifetime Project Estimate at Complete, and Lifetime Project Variance at Complete.

Each month, the SteerCo will make decisions on cost, scope, or budget items as required by the Project Execution Plan. The project manager reserves the right to present items not outlined in the Project Execution Plan if he/she determines its importance is relevant to SteerCo input.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The final decisions regarding these items, especially certain change requests as required by the Project Exectuion Plan, will be presented to, and voted upon by the SteerCo. The decisions will be documented in a monthly meeting minutes of the SteerCo for documentation and oversight.

It will be the Project Manager's role to monitor the scope, budget, and schedule and present the results to the SteerCo, regardless of they are within tolerances, or not.

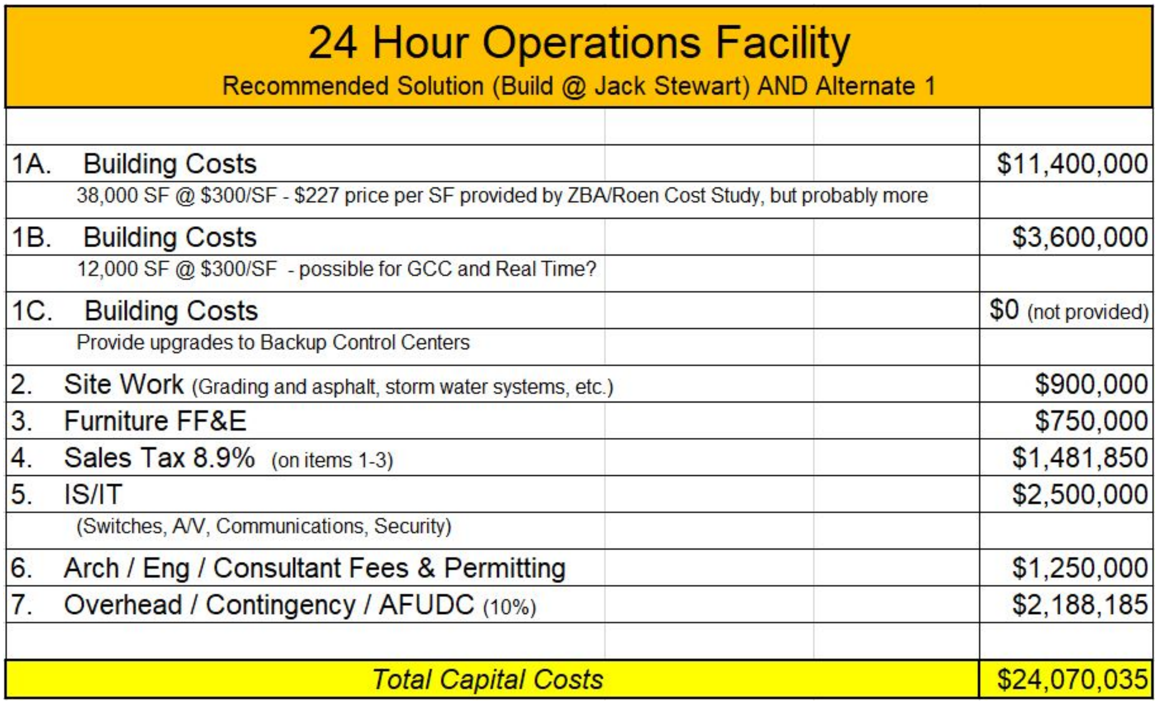
The undersigned acknowledge they have reviewed the *Central 24 Hr Operations Facility* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Eric Bowles	Date:	8/4/2020
Print Name:	Eric Bowles		
Title:	Corp Facilities Manager		
Role:	Business Case Owner		

Signature:	Dan Johnson	Date:	08/04/2020
Print Name:	Dan Johnson		
Title:	Director of Shared Services		
Role:	Business Case Sponsor		

Template Version: 05/28/2020

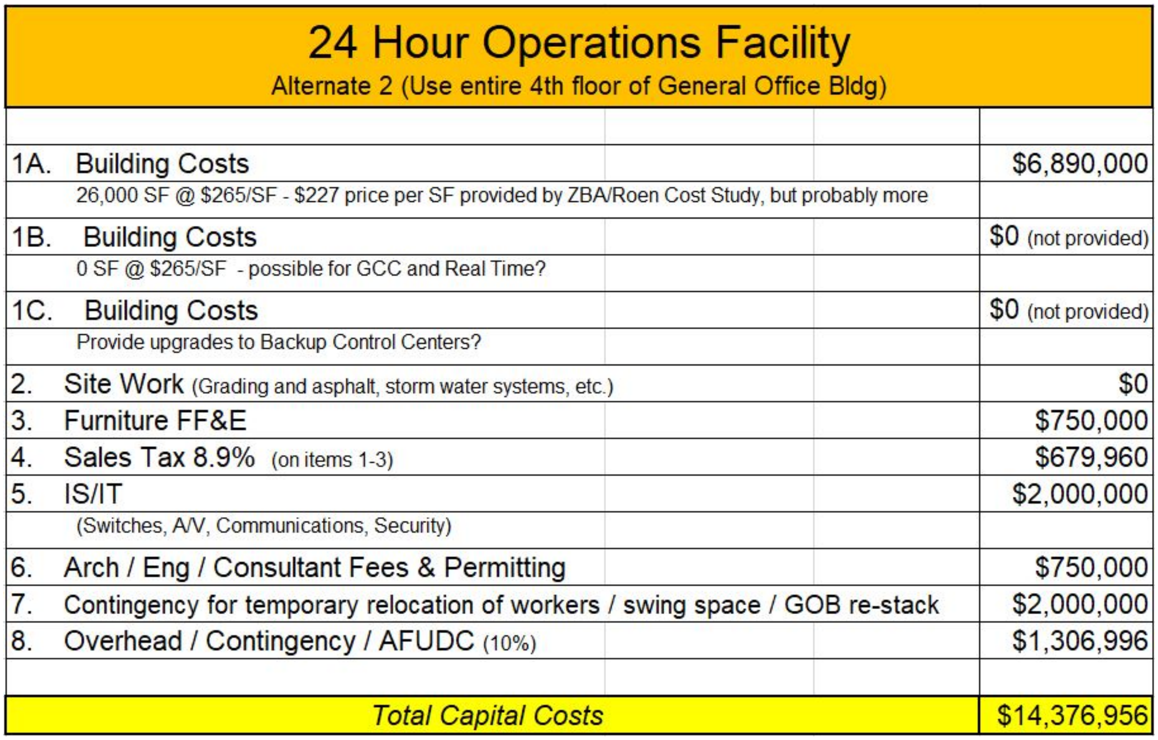
Appendix A – Cost Estimate Breakdowns



24 Hour Operations Facility

Recommended Solution (Build @ Jack Stewart) AND Alternate 1

1A. Building Costs	$11,400,000
38,000 SF @ $300/SF - $227 price per SF provided by ZBA/Roen Cost Study, but probably more	
1B. Building Costs	$3,600,000
12,000 SF @ $300/SF - possible for GCC and Real Time?	
1C. Building Costs	$0 (not provided)
Provide upgrades to Backup Control Centers	
2. Site Work (Grading and asphalt, storm water systems, etc.)	$900,000
3. Furniture FF&E	$750,000
4. Sales Tax 8.9% (on items 1-3)	$1,481,850
5. IS/IT	$2,500,000
(Switches, A/V, Communications, Security)	
6. Arch / Eng / Consultant Fees & Permitting	$1,250,000
7. Overhead / Contingency / AFUDC (10%)	$2,188,185
Total Capital Costs	$24,070,035



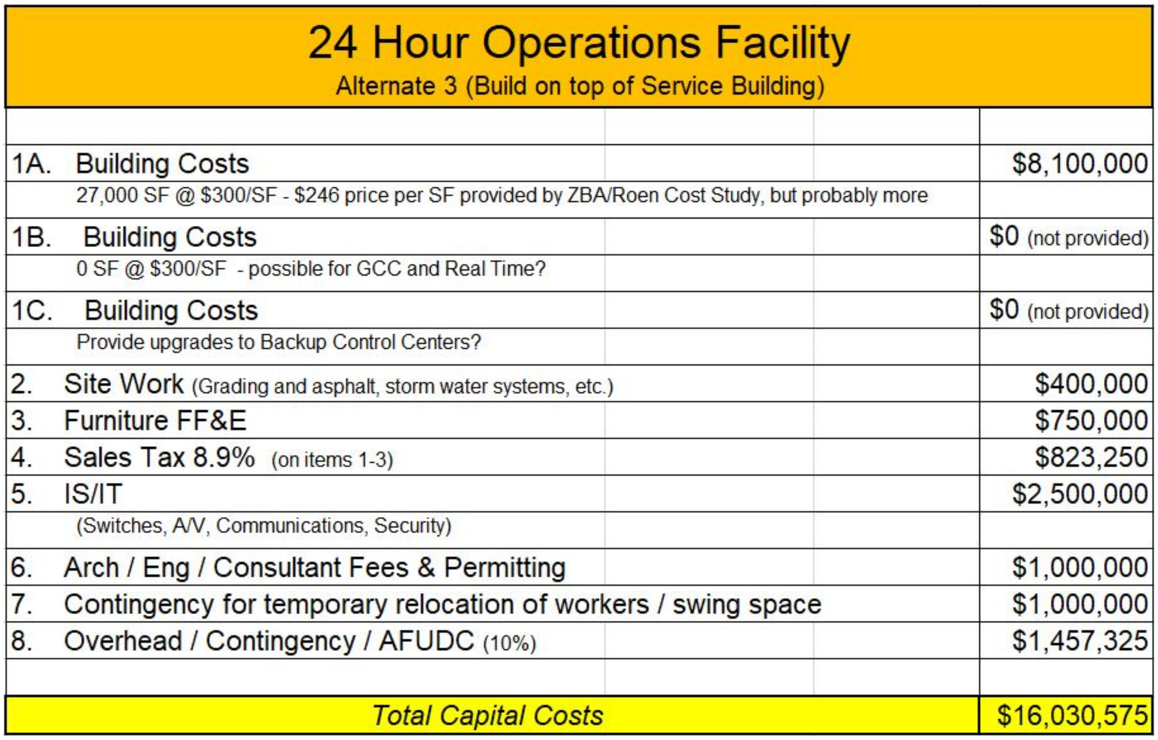
24 Hour Operations Facility

Alternate 2 (Use entire 4th floor of General Office Bldg)

1A. Building Costs	$6,890,000
26,000 SF @ $265/SF - $227 price per SF provided by ZBA/Roen Cost Study, but probably more	
1B. Building Costs	$0 (not provided)
0 SF @ $265/SF - possible for GCC and Real Time?	
1C. Building Costs	$0 (not provided)
Provide upgrades to Backup Control Centers?	
2. Site Work (Grading and asphalt, storm water systems, etc.)	$0
3. Furniture FF&E	$750,000
4. Sales Tax 8.9% (on items 1-3)	$679,960
5. IS/IT	$2,000,000
(Switches, A/V, Communications, Security)	
6. Arch / Eng / Consultant Fees & Permitting	$750,000
7. Contingency for temporary relocation of workers / swing space / GOB re-stack	$2,000,000
8. Overhead / Contingency / AFUDC (10%)	$1,306,996
Total Capital Costs	$14,376,956

Exh. HLR-2

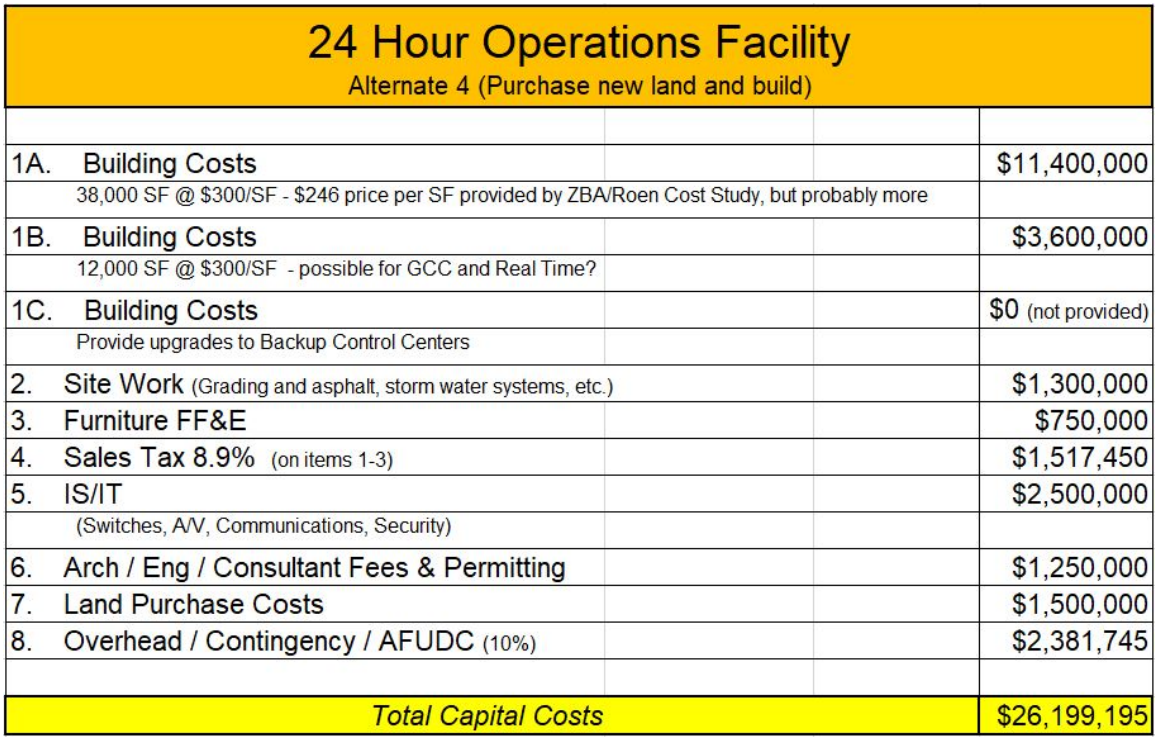
Central 24 HR Operations Facility



24 Hour Operations Facility

Alternate 3 (Build on top of Service Building)

1A.	Building Costs	$8,100,000
	27,000 SF @ $300/SF - $246 price per SF provided by ZBA/Roen Cost Study, but probably more	
1B.	Building Costs	$0 (not provided)
	0 SF @ $300/SF - possible for GCC and Real Time?	
1C.	Building Costs	$0 (not provided)
	Provide upgrades to Backup Control Centers?	
2.	Site Work (Grading and asphalt, storm water systems, etc.)	$400,000
3.	Furniture FF&E	$750,000
4.	Sales Tax 8.9% (on items 1-3)	$823,250
5.	IS/IT	$2,500,000
	(Switches, A/V, Communications, Security)	
6.	Arch / Eng / Consultant Fees & Permitting	$1,000,000
7.	Contingency for temporary relocation of workers / swing space	$1,000,000
8.	Overhead / Contingency / AFUDC (10%)	$1,457,325
	Total Capital Costs	$16,030,575



24 Hour Operations Facility

Alternate 4 (Purchase new land and build)

1A.	Building Costs	$11,400,000
	38,000 SF @ $300/SF - $246 price per SF provided by ZBA/Roen Cost Study, but probably more	
1B.	Building Costs	$3,600,000
	12,000 SF @ $300/SF - possible for GCC and Real Time?	
1C.	Building Costs	$0 (not provided)
	Provide upgrades to Backup Control Centers	
2.	Site Work (Grading and asphalt, storm water systems, etc.)	$1,300,000
3.	Furniture FF&E	$750,000
4.	Sales Tax 8.9% (on items 1-3)	$1,517,450
5.	IS/IT	$2,500,000
	(Switches, A/V, Communications, Security)	
6.	Arch / Eng / Consultant Fees & Permitting	$1,250,000
7.	Land Purchase Costs	$1,500,000
8.	Overhead / Contingency / AFUDC (10%)	$2,381,745
	Total Capital Costs	$26,199,195

North Lewiston Auto Transformer Replacement

EXECUTIVE SUMMARY

The North Lewiston 230/115 kV Transformer 1 (McGraw-Edison Serial Number C-06237-5-2) located in Lewiston, ID failed in February 2021. A replacement transformer has been ordered and will be installed in 2022. The North Lewiston 230/115kV Transformer 1 provides the transformation capacity needed for the system to meet performance requirements as defined by System Planning and System Operations.

The North Lewiston 230/115 kV Transformer 1 was 40 years old when it failed. Following the failure, an investigation was performed with testing and an internal inspection. The investigation concluded the transformer had a failed winding. The decision to replace the 230/115 kV Transformer 1 was made based on an evaluation of alternatives which also included rebuilding the existing transformer and utilizing a spare transformer within Avista's system.

Service Code: Electric Direct

Jurisdiction: Allocated North

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Karen Kusel	Draft, Preliminary Dollars	04/26/2021	
Draft_SK	Sara Koeff	Revision	06/1/2021	
Draft_rev2	Keri Gross	Revision	06/07/2021	

North Lewiston Auto Transformer Replacement

GENERAL INFORMATION

Requested Spend Amount	$4,100,000
Requested Spend Time Period	2 Years
Requesting Organization/Department	Substation Engineering
Business Case Owner | Sponsor	Glenn Madden | Heather Rosentrater
Sponsor Organization/Department	M08 / Substation Engineering
Phase	Planning
Category	Project
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

The night of 2/27/2021 there was a B to ground fault on the North Lewiston tap of the Lolo-Pound Lane 115 kV line. The following morning, 2/28/2021, a major alarm came in on the North Lewiston 230/115kV Transformer 1. The alarm was driven by the Online Dissolved Gas Analysis (DGA) Monitor. The DGA showed an increase in multiple gasses coinciding with the timing of the transmission line fault. Due to the increase in gasses, the transformer was taken out of service to perform electrical testing on it. The excitation current and sweep frequency response analysis (SFRA) tests had irregularities in the test results. An internal inspection was performed, which confirmed that there was a H2 (B phase) winding turn-to-turn fault and at least one parallel winding strand that had broken open. The North Lewiston 230/115 kV Transformer 1 was deemed to have a failed winding and unable to be put back into service. For complete details on the investigation effort see "North Lewiston Auto 1 Investigation Analysis" report.

North Lewiston Auto Transformer Replacement

1.2 Discuss the major drivers of the business case

The major driver for this project is Failed Plant & Operations. The North Lewiston 230/115 kV Transformer 1 provides the transformation capacity needed for Avista's system to meet performance requirements as defined by System Planning and System Operations.

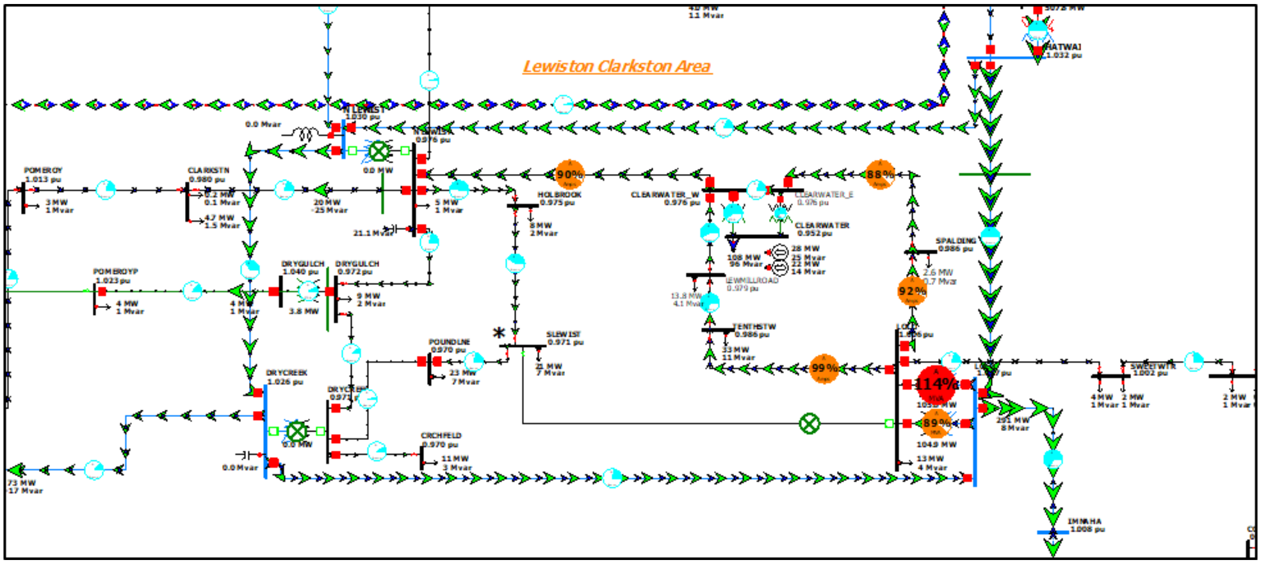
1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

The 2019-2020 Avista System Assessment, Appendix D documents the studies performed by System Planning showing what may result on Avista's system with the loss of the North Lewiston 230/115kV Transformer. Studies were performed according to NERC standard TPL-001-4 requirement R2.1.5; below is a summary from the Assessment.

• Overload of the Lolo #1 230/115kV Transformer for outages involving the Dry Creek 230/115kV Transformer, Lolo #2 230/115kV Transformer or the Dry Creek 115kV bus. (See below figure)

• Overload of the Dry Creek – North Lewiston 115kV Transmission Line for outages involving the Lolo 115kV bus.

• Area low voltage for outages involving the Lolo 115kV bus.



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.

Replacing the North Lewiston 230/115 kV Transformer 1 will return the electric system in the Lewiston / Clarkston area to normal operating conditions.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Avista crews performed initial testing of the North Lewiston 230/115 kV Transformer. The test results indicated performance issues and further testing was needed. North American Substation Services (NASS) performed a Sweep Frequency Response Analysis (SFRA). Doble Engineering analyzed the Avista and NASS test results. An internal inspection of the transformer showed evidence of broken winding coil and coil movement.

See the "North Lewiston Auto 1 Investigation Analysis" attachment for inspection and testing details.

See the "2019-2020 Avista System Assessment - V2 - Appendix D" attachment for details of system performance concerns associated with the transformer outage.

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 North Lewiston 230/115 kV Transformer had a H2 (B phase) winding turn-to-turn fault and at least one parallel winding strand broke open. The transformer was deemed to have a failed winding and unable to be put back into service.

See the "North Lewiston Auto 1 Investigation Analysis" for details on the condition of the failed transformer.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
[Recommended Solution] Replace 230/115 kV Transformer	$4.1M	02-2021	6-2022
[Alternative #1] Repair 230/115 kV Transformer	Unknown	02-2021	Unknown
[Alternative #2] Relocate 230/115 kV Transformer to NLW	N/A	02-2021	N/A

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Project cost and project completion date were priority considerations for restoring the transmission system to meet performance requirements in the Lewiston/Clarkston area. Replacing the failed North Lewiston 230/115 kV Transformer has the lowest project cost and restores the transmission system with the shortest and most predictable timeline.

See "North Lewiston Auto Transformer Failure and Replacement" for analysis of the project options.

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.

2021 – Purchase new transformer, remove old transformer and associated equipment, engineering / drafting costs. (~$ 3.35M)

2022 – Receive new transformer at North Lewiston Substation, install new transformer and associated equipment, test and commission new transformer, engineering / drafting costs. (~$ 0.75M)

There will be no substantial increase in O&M expenses after this transformer replacement.

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 business case impacts work within Transmission and Distribution by postponing a few projects about two months.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Alternative #1: The option to repair the existing failed transformer has an unknown cost and project completion due to the difficulty of locating a domestic facility capable of repairing the atypical design. If a repair facility is located, there are concerns if the repair could bring the existing transformer to current component specifications as quick as or quicker than purchasing a new transformer. Additionally, there are cost and timeline concerns with the round-trip transportation of the existing transformer, including possibly to an overseas facility, due to the present worldwide pandemic restrictions and shipping interruptions.

Alternative #2: Avista does not own a spare 230/115 kV Transformer or have sufficient capacity in the remaining parts of the system to relocate an already in service 230/115 kV Transformer.

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.

February/March 2021 – Inspection, testing, and analysis of options leading to decision to replace autotransformer

Remainder of 2021 – Order replacement transformer. Engineering to scope and design replacement. Remove/recycle failed transformer by contractor. Site prep work is completed before installation begins.

2022 – New transformer is received onsite. Avista crews complete installation of transformer. Testing and Commissioning is completed. Autotransformer is energized by mid-year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Perform:

The proposed investment is critical to serving our customers well. The North Lewiston 230/115 kV Transformer is required to safely and responsibly serve our customers. Once it was determined to have failed, Avista performed timely and necessary analysis to determine the most affordable path forward. Purchasing a new transformer to replace the failed transformer provides ‘Better Energy for Life’.

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

Based on System Planning’s 2019-2020 System Assessment, the North Lewiston 230/115 kV Transformer is necessary to meet performance requirements. Replacing the transformer will return the system to its normal operating condition.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Substation Engineering, Protection Engineering, GPSS Electric Shop, GPSS Mechanical/Structural Shop, GPSS Relay Shop, Drafting Department, System Planning, System Operations, Network Communications, Project Accounting, SCADA Support, Asset Management.

2.8.2 Identify any related Business Cases

There are no related Business Cases.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Capital Planning Group, Engineering Roundtable

3.2 Provide and discuss the governance processes and people that will provide oversight

Any major changes to the project will go to the Engineering Round Table (ERT). The Substation Engineering Manager and System Operations will provide oversight to the project.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Lead Substation Engineer will coordinate decisions through those who provide oversight and document those decisions as necessary.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the North Lewiston Auto Transformer Replacement 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: Glenn J Madden Date: 1-3-2022
Print Name: Glenn Madden
Title: Manager, Substation Engineering
Role: Business Case Owner

Signature: Heather Rosentrater Date: 1-4-2022
Print Name: Heather Rosentrater
Title: Senior VP, Energy Delivery
Role: Business Case Sponsor

Signature: Damon Fisher Date: 1/4/2022
Print Name: Damon Fisher
Title: Engineering Roundtable
Role: Steering/Advisory Committee Review

Oil Storage Improvements

EXECUTIVE SUMMARY

In the 1990s, an underground vault was built at the Mission Campus to house several tanks intended to hold new oil, used but viable oil, and scrap oil, all related to substation maintenance and electrical distribution operations. This system connected the electric shop and the scrap oil recovery areas through a series of manifolds and pumps to segregate the new and used oils. Several incidents, including one holiday weekend overfill incident in 2010, brought to light the disadvantage of using an underground system, as problems could go undetected. This risk was further highlighted during a 2019 pipeline spill and subsequent investigation/excavation and cleanup.

In 2014, two new above-ground scrap oil storage tanks were built as part of the Waste & Asset Recovery (WAR) Building. This allowed for the two scrap tanks in the underground vault to be decommissioned, but the remaining four underground tanks, and associated underground piping, remain in use. This system still poses risks of undetected leaks. In addition, access to the underground system becomes more problematic as we redevelop the campus. The vault space itself limits use of the area. Finally, the vault has been subject to intrusion by water, and maintenance costs to ensure the vault provides proper containment are increasing.

The recommended solution will build two additional new oil tanks by the WAR Building, with several smaller “day” containers for the Electric Shop, allowing the underground vault to be permanently removed, eliminating environmental risk.

The recommended solution is estimated to cost $1.8 million (as of July 2021). There will be two rate jurisdictions for this project. For the actual oil tanks and dispensing equipment, since they will only be used for Substation Support, the costs will be filed under Electric Only – WA & ID. All other associated site improvements, since they could be used by any business unit at the Mission Campus, will be filed with the rate jurisdiction of Common Direct – Allocated All. The major customer benefit would be the reduction in future O&M maintenance, and costs of clean up of environmental events. Customers will also benefit with an enhanced oil storage process that will provide Avista employees with reduced overall environmental risk, time efficiencies and generally faster response times within substation maintenance. It is recommended to proceed with this business case as soon as possible to avoid any additional environmental risk and inefficiencies utilizing the existing system.

VERSION HISTORY

Version	Author	Description	Date	Notes
0.0	Vance Ruppert	Initial draft to be approved by Sponsors	7/6/2020	
1.0	Vance Ruppert	Final Draft, Sponsor edits incorporated	7/10/2020	
1.1	Vance Ruppert	BCJN update for 2022-26 Capital Planning	7/9/2021	

Oil Storage Improvements

GENERAL INFORMATION

Requested Spend Amount	$1,800,000
Requested Spend Time Period	2 years#
Requesting Organization/Department	Shared Services (Facilities)
Business Case Owner | Sponsor	BC Owner: Eric Bowles Sponsors: Bruce Howard, Andy Vickers, and Alicia Gibbs
Sponsor Organization/Department	Environmental / GPSS / Shared Services
Phase	Initiation
Category	Project
Driver	Asset Condition

Oil Storage Improvements

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

In the 1990s, an underground vault was built at the Mission Campus which housed several tanks that were intended to hold new oil, used but viable oil, and scrap transformer oil, all related to substation maintenance and electrical distribution operations. Over time, there have been several incidents of an environmental regulatory nature that began to question the ongoing practicality of retaining this asset.

A. The prime event occurred in September 2019, when an Electric Shop Electrician discovered a pipe rupture into the containment vault after operating the system for approximately 30 minutes. The pipe connects the vault and the Electric Shop (a substation maintenance shop) within the Service Building (one of several standalone buildings on the Mission Campus). The leak released an estimated two hundred gallons of oil, and required excavation to a depth of 15 feet deep and approximately 31 cubic yards of soil. The system is currently curtailed to direct pumping operations from the containment building, which is cumbersome to Avista personnel. We are awaiting confirmation from Washington State Department of Ecology for a “no further action” letter regarding site cleanup.

B. Another incident occurred in 2010, when an oil transfer occurred on a Friday with electric shop personnel and a contractor. The wrong tank was selected to fill, the oil overflowed out of the tank and oil was allowed to float on the floor for over three days as it was a holiday weekend. It is unknown if the oil significantly penetrated the concrete floor, but some concrete may have been contaminated. Designation and disposal will occur under this business case.

C. O&M dewatering - The roof to the underground vault is an asphalted lid that doubles as a drive path for Avista vehicles. However, water seeps down into the vault through cracks and porous surfaces. This problem has accelerated through the years and requires a hazardous waste technician to pump out the water, and screen it for oil/PCB contamination before disposing of it. This occurs 5-10 times per year.

D. The oil storage vault is a “stranded asset” as multiple stakeholders claim use of the resource, without a single stakeholder that “owns” the asset for O&M checks or maintenance. O&M checks are currently performed by Hazardous Waste Technicians and Security contractors to ensure that oil isn’t present in the containment on a weekly basis.

1.2 Discuss the major drivers of the business case and the benefits to the customer

The major driver for this Business Case is “Asset Condition,” due to its containment failures and environmental risks as outlined in Section 1.1. The major customer benefit would be the offset of any future O&M maintenance or clean up of environmental events. Customers will also benefit with an enhanced oil storage process that will provide Avista employees with time efficiencies and generally faster response times within substation maintenance.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

With the past failures as outlined above, it is Avista’s belief that a major environmental event with the underground vault is a matter of when, not if. Avista cannot predict when that event would occur, be it months or years. However, in general, the longer this Business Case is not implemented, the greater the chance the risk could occur without the problem being fixed.

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.

At this time, the only measure that can be used is to design an oil storage system that takes lessons learned from the underground vault and uses them to mitigate risks. Some measures include a system that will:

1) be easily viewable by multiple employees on a daily basis to check for leaks

2) not use any underground tanks or piping

3) use oil containment best practices such as: active electronic monitoring, modern pumping equipment, reinforced single or double-walled tanks, weathertight roofing, purpose-built concrete containment with impermeable coating.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

2010 CH2M Hill Assessment of Underground Storage Tanks for Avista. Available on request (Facilities / Vance Ruppert).

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.

Pictures of the underground pipe oil leak as described in Section 1.1 (A) above are available on request (Facilities / Vance Ruppert).

Pictures of the oil tank overflow as described in Section 1.1 (B) above are available on request (Facilities / Vance Ruppert).

Pictures of the annual water roof leaks as described in Section 1.1 (C) above are available on request (Facilities / Vance Ruppert).

Option	Capital Cost	Start	Complete
Recommended Option: Build new above ground tanks, demolish underground vault and tanks	*$1.8M* *(see note 1 below)*	*06/2021*	*10/2022*
Alternate #1: Build a new GPSS Maintenance Shop at Mission or off-site, with a new tank(s) arrangement.	*$15M - $25M (?)*	*2021 (?)*	*2023 (?)*

Notes:

1) See Appendix A for further cost estimate breakdowns of the Recommended Option's $1.8M Capital Cost as shown in the table above.

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The main intent of this project is to avoid significant environmental risks as described in Section 1.1 Any risks that actually occur carry with it significant O&M costs as well. For instance, the underground pipe oil leak as described in Section 1.1(A) had a remediation cost of approximately $100,000.

If (and when) a major environmental risk were to occur with the underground vault, such as a burst oil tank and vault containment failure, a remediation cost of the soil below the vault would probably start at $200,000, and would potentially reach multiples of that amount if the contamination reached groundwater. Avista would be subject to environmental enforcement, penalties, and significant reputational harm.

Avista Facilities employee time to contend with the other issues in Section 1.1 can range from a few hours to several days. A conservative estimation of an average Avista Facilities maintenance employee labor rates, which includes hour rates, overhead, and benefits, is at least $60 an hour. If an average estimate of each event requires 2 employees for 4 hours, 1 time a month, then yearly O&M savings could be assumed to be $5,760.

In addition, the Avista senior hazardous waste technician ($75 per hour) spends at least two and a half hours per event (with 5-10 events every year) to dewater the vault as described in Section 1.1 (C). The 10 event estimate would calculate to a yearly O&M savings of approximately $1,875, plus disposal costs of approximately $1000. Should cross contamination of water occur, costs would increase by orders of magnitude.

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). Include any known or estimated reductions to O&M as a result of this investment.

The requested capital cost amount of $1.8M will be broken out between two years. In 2020, $300K will be requested to design, permit, and competitively bid the project to a general contractor. In addition, some monies will be used to conduct environmental investigations to determine if there are any additional unknown contaminations or failures. The remaining $1.5M will be primarily for construction in 2021.

The project will provide the following new equipment and processes:

Two new 10,000 gallon tanks, one for new oil, and one for used but viable oil. They shall be installed near the existing tanks at the Waste & Asset Recovery Building (WAR Bldg). The tanks shall be above ground, surrounded by a concrete spill containment. They will also require a covered roof/canopy, and may also require metal siding to prevent snow/rain accumulation in the containment.

A smaller racked oil storage containers will be purchased for the Electric Shop for day use.

The new oil tank will be filled as needed by our oil supply vendor. The used but viable oil tank will be filled by our Electric Shop (ES), a department within Avista's Generation Production Substation Support (GPSS) business unit.

A 500 gallon portable storage tote to be filled with new oil from the tank mentioned above. It will be filled as required by the ES, but it is expected to be no more than 2-3 times a year.

A 300 gallon portable storage tote to be filled with used but viable oil, or to transport scrap oil to, the tank mentioned above. It will be used as required by the ES, but it is expected to be no more than 2-3 times a year.

A storage area (concrete slab or asphalted) will be provided for 20 empty 55 gallon drum barrels for new or used oil as required by the ES.

A storage area (concrete slab or asphalted), with a covered roof/canopy, will be provided for 12 full 55 gallon drum barrels for new oil as required by the ES. It may also require metal siding to prevent snow/rain accumulation in the storage area.

The ES will forklift the totes to and from the WAR Building. Due to the storm water containment systems and oil water separators that have been installed on the Mission Campus over the past decades, the risk of any major oil spill events from forklift traffic is extremely low.

The new oil tank will also provide oil to an approx. 3000 gallon Isuzu tanker truck or an 8000 gallon tanker trailer Avista owns and stores at our Beacon Substation. Both pieces of equipment will be used as needed for large substation equipment work at both at the Mission Campus ES, and in the field / at any particular substation.

Demolish the existing underground vault. Technique of demolition T.B.D. Option 1: remove the entire vault including the floor slab and footings, or Option 2: remove only 6 feet or so top-down, with existing slab and footings to remain. The removed underground vault will be replaced with a new asphalt parking lot, approximately the same footprint, for GPSS use.

There is a possibility this project would include adding siding and slider doors to the (2) existing tanks at the WAR Bldg., due to snow/rain/ice accumulation inside its concrete containment the past few years.

In addition to the O&M savings for Avista employees as described in Section 2.1, it can be conservatively estimated that this new process will save at least 30 minutes for two ES employees at least once a week. The yearly O&M savings, using a $75 ES employee rate, can be assumed to be $3,900.#

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Current processes, metrics, & data:

1) Currently, the underground vault has four tanks that can be used by the Electric Shop (ES). There are (2) 10,000 gallon tanks to hold oil, and (2) 5000 gallon tanks subdivided into (4) 2500 gallon compartments that hold new or used but viable oil. The (2) 5000 gallon tanks can be used as queuing tanks from either of the 10,000 gallon tanks.
2) The 5000 gallon tanks were previously accessed by the ES through direct underground plumbing coming from the vault directly into the ES. The controls for switching between all the tanks, and also the (4) 2500 gallon subdivided tanks, are in the vault.
3) Inside of the ES, 55 gallon drums/totes (usually around four total) were being filled using the direct plumbed line. This practice recently ended however, due to the discovery of the leak in the underground piping as described in Section 1.1 (A). Now that the underground plumbing is no longer usable, if the totes need refilling, they will be forklifted over to the external, above-ground, hose hook up located at the vault.
4) Once the full totes are placed back in the ES, the oil is manually pumped into “smaller” pieces of equipment, as needed. Since the smaller equipment doesn’t usually require much oil, the totes only need to be refilled maybe twice, or three times a year.
5) However, the ES will sometimes require thousands of gallons at one time to work on larger equipment such as power transformers or oil circuit breakers, on a scheduled or emergency basis. Instead of using the totes, the ES has a separate process.
    a. Use the large tanker trailer or the smaller Isuzu tanker truck stored at Beacon Substation.
    b. More often than not, the ES will work on large equipment in the field / at the substation. They will fill the Isuzu or our tanker trailer at our vault at Mission Campus. After filling, they will then drive to the substation to dispense.

6) Lastly, whenever the ES needs a refill of either 10,000 gallon tank in the underground vault, they will usually have to "shuffle" some oil between the 10,000 gallon tanks and the 5000 gallon tanks in order to receive the full approx. 8000 gallons of oil for any tanker truck delivery from our vendor.

All of the above current processes will be replaced by the new processes as described above in Section 2.2.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

There was some discussion to build a new GPSS Shops Maintenance Building either at the Mission Campus, or at another off-site location. There is significant risk that the scope of such a building could fluctuate and produce a project requiring anywhere from $15M - $25M. At this time, this is not a reasonable solution to the main problem – the environmental issues with the underground vault and tanks.

Doing nothing was also considered, but given the difficulties numerous departments such as Facilities, Environmental, and GPSS have endured the past few decades, as well as the risk of a major future environmental event, the do nothing option is also not reasonable.

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. spend, and transfers to plant by year.

This business case is considered a project, as it is not intended to be an ongoing project beyond 2022. The major milestones and timeline of the project is estimated to be the following:

Complete Design Drawings: 5 months

Bidding / permits complete, General Contractor (GC) selection: 2 months

GC procure tanks and long lead items: 2-3 months

GC complete new tanks: 4 months

GC complete demolition of underground vault: 2 months

The project is expected to complete and become used and useful in early-to-mid Q4 of 2022, with all of its $1.8M transferring to plant in 2022, around the same timeframe.

#

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The major reason to perform this project is to align with Avista's strategic vision of environmental stewardship. This Business Case clearly identifies the environmental regulatory issues that could occur at some point if no action is taken.

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

The environmental regulatory issues and O&M maintenance described in the business case earlier makes a strong case that this investment makes sense, as to avoid significant operational and environmental risks. As the project progresses, the scope and budget will be re-baselined as required, with the expectation of meeting scope, schedule, and budget targets.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Major customers/stakeholders:

Environmental Department (Bruce Howard, Darrell Soyars, Bryce Robbert, Heath Peterson, Casey Cardenas, Luke Pate)

Generation Production / Substation Support Department (Andy Vickers, Alexis Alexander, Brad McNamara, Loren Davidson)

Facilities (Alicia Gibbs, Eric Bowles, Robert Johnson, Nick Lasko, Vance Ruppert)

Minor customers/stakeholders:

Electric Operations, Fleet Maintenance, Warehouse/Stores

2.8.2 Identify any related Business Cases

Not applicable.

3.1 Steering Committee or Advisory Group Information

A. The Steering Committee (SteerCo) (as of July 2021) shall consist of the following: Alicia Gibbs, Mike Faulkenberry, Andy Vickers, David Howell, Jim Corder, Lauren Pendergraft, Mike Magruder, and Bruce Howard.

B. The Advisory Group that assisted in shaping this Business Case consisted of the following stakeholders:

Environmental Department (Bruce Howard, Darrell Soyars, Bryce Robbert)

Generation Production / Substation Support Department (Andy Vickers, Brad McNamara)

Facilities (Dan Johnson, Eric Bowles, Robert Johnson, Dave Schlicht, Nick Lasko, Vance Ruppert)

3.2 Provide and discuss the governance processes and people that will provide oversight

The project shall use certain Project Management Professional (PMP) guidelines and procedures during the course of this project.

A Project Execution Plan, consisting of the documents below, will be drafted and approved by the SteerCo described in Section 3.1 (A).

- Project Charter, Change Management Plan, Communication Management Plan, Cost Management Plan, Procurement Management Plan, Project Team Management Plan, Risk Management Plan and Risk Register, Schedule Management Plan, Scope Management Plan, and Project Execution Approval Form.

Each month, the project manager will provide the following information either at the scheduled SteerCo meeting, or via email.

- Approved Yearly Budget, Accrued Yearly to Date, Year Estimate at Complete, Year Variance at Complete, Approved Lifetime Budget, Accrued Lifetime to Date, Lifetime Project Estimate at Complete, and Lifetime Project Variance at Complete.

Each month, the SteerCo will make decisions on cost, scope, or budget items as required by the Project Execution Plan. The project manager reserves the right to present items not outlined in the Project Execution Plan if he/she determines its importance is relevant to SteerCo input.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The final decisions regarding these items, especially certain change requests as required by the Project Execution Plan, will be presented to, and voted upon by the SteerCo. The decisions will be documented in a monthly meeting minutes of the SteerCo for documentation and oversight.

It will be the Project Manager’s role to monitor the scope, budget, and schedule and present the results to the SteerCo, regardless of they are within tolerances, or not.

Oil Storage Improvements

The undersigned acknowledge they have reviewed the *Oil Storage Improvements 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: Eric Bowles 4ACC724D48764C2... Date: Jul-08-2021 | 8:34 AM PDT
Print Name: Eric Bowles
Title: Corp Facilities Manager
Role: Business Case Owner

Signature: DocuSigned by: Alicia Gibbs 49C42855345E488... Date: Jul-08-2021 | 10:15 AM PDT
Print Name: Alicia Gibbs
Title: Director of Shared Services
Role: Business Case Sponsor

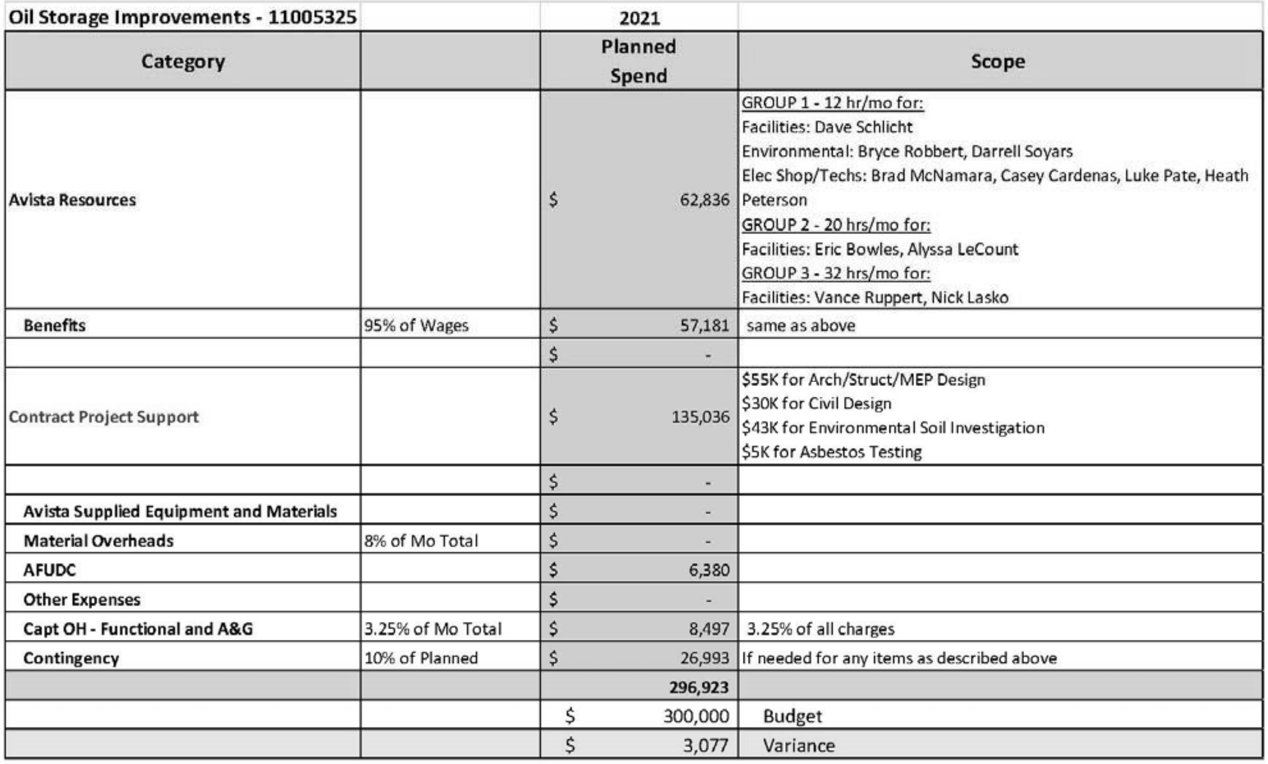
Signature: DocuSigned by: Bruce Howard CDB9B5DDD0114A5... Date: Jul-08-2021 | 8:19 AM PDT
Print Name: Bruce Howard
Title: Sr Director of Environmental Affairs
Role: Business Case Sponsor

Signature: DocuSigned by: Andy Vickers 8E5EBAEFABB04AA... Date: Jul-08-2021 | 8:46 AM PDT
Print Name: Andy Vickers
Title: Director GPSS
Role: Business Case Sponsor

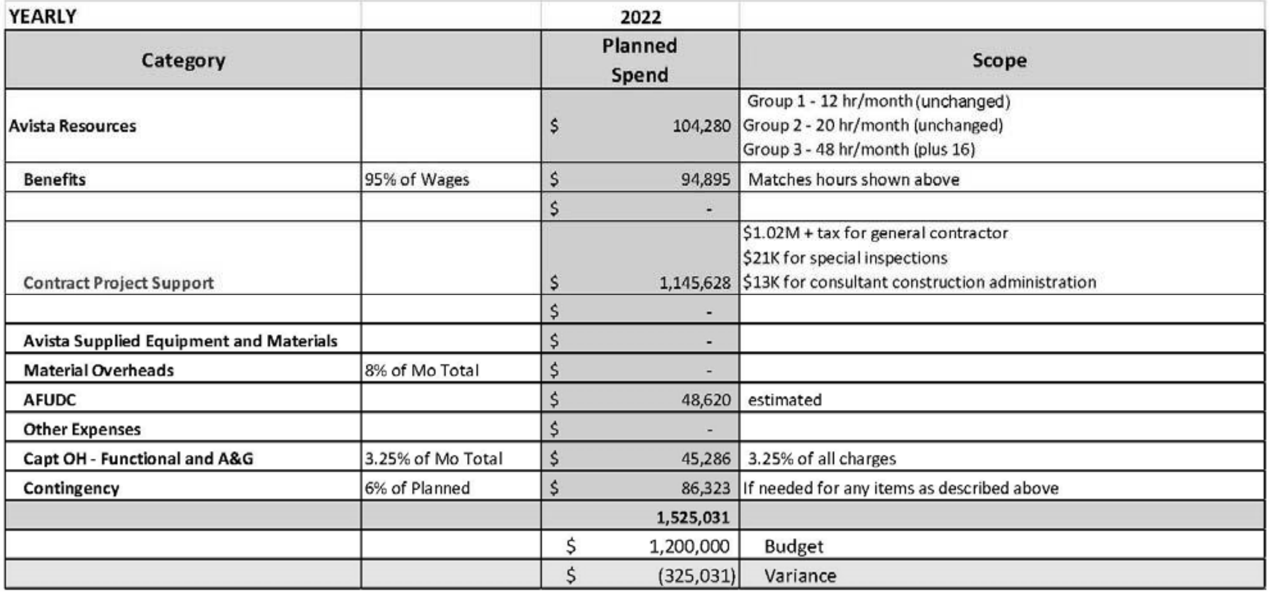
Template Version: 05/28/2020

Appendix A – Cost Estimate Breakdown

Presented and approved by Facilities Steering Committee to request additional funds through the Capital Planning Group on June 10, 2021.



Oil Storage Improvements - 11005325		**2021**	
Category		**Planned Spend**	**Scope**
Avista Resources		$ 62,836	GROUP 1 - 12 hr/mo for: Facilities: Dave Schlicht Environmental: Bryce Robbert, Darrell Soyars Elec Shop/Techs: Brad McNamara, Casey Cardenas, Luke Pate, Heath Peterson GROUP 2 - 20 hrs/mo for: Facilities: Eric Bowles, Alyssa LeCount GROUP 3 - 32 hrs/mo for: Facilities: Vance Ruppert, Nick Lasko
Benefits	95% of Wages	$ 57,181	same as above
		$ -	
Contract Project Support		$ 135,036	$55K for Arch/Struct/MEP Design $30K for Civil Design $43K for Environmental Soil Investigation $5K for Asbestos Testing
		$ -	
Avista Supplied Equipment and Materials		$ -	
Material Overheads	8% of Mo Total	$ -	
AFUDC		$ 6,380	
Other Expenses		$ -	
Capt OH - Functional and A&G	3.25% of Mo Total	$ 8,497	3.25% of all charges
Contingency	10% of Planned	$ 26,993	If needed for any items as described above
		296,923	
		$ 300,000	Budget
		$ 3,077	Variance



YEARLY		**2022**	
Category		**Planned Spend**	**Scope**
Avista Resources		$ 104,280	Group 1 - 12 hr/month (unchanged) Group 2 - 20 hr/month (unchanged) Group 3 - 48 hr/month (plus 16)
Benefits	95% of Wages	$ 94,895	Matches hours shown above
		$ -	
Contract Project Support		$ 1,145,628	$1.02M + tax for general contractor $21K for special inspections $13K for consultant construction administration
		$ -	
Avista Supplied Equipment and Materials		$ -	
Material Overheads	8% of Mo Total	$ -	
AFUDC		$ 48,620	estimated
Other Expenses		$ -	
Capt OH - Functional and A&G	3.25% of Mo Total	$ 45,286	3.25% of all charges
Contingency	6% of Planned	$ 86,323	If needed for any items as described above
		1,525,031	
		$ 1,200,000	Budget
		$ (325,031)	Variance

Gas Above Grade Pipe Remediation Program, ER 3009

EXECUTIVE SUMMARY

Within the natural gas distribution system of all three states, there are sections of gas pipelines that are located above grade. These above grade crossings have a variety of construction techniques and supporting structures. This Business Case addresses capital expenditures associated with remediating these sites. Each location will be unique in how it is his corrected and the costs will vary depending on the complexity of the project. Resolution will typically involve either installing new pipe below grade or rebuilding the existing crossing.

It is recommended to spend $750,000 per year mitigating these crossings. This will fund one large directional drill project, or several medium to small sized projects per year. This mitigation work will ensure our gas pipeline facilities are operating with reduced risk and will create a safe and reliable system for our communities and customers. If this program is not started, Avista will be at risk of:

- fines from the State PUC's for being out of compliance with federal safety codes,
- pipeline failures if support structures fail,
- environmental fines if a pipeline failure results in a release of gas, and
- temporary loss of service to downstream gas customers.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb	Initial submission of original business case	7/8/21	

Gas Above Grade Pipe Remediation Program, ER 3009

GENERAL INFORMATION

Requested Spend Amount	$750,000
Requested Spend Time Period	*> 5 years*
Requesting Organization/Department	Gas Engineering, B51
Business Case Owner | Sponsor	Jeff Webb
Sponsor Organization/Department	Mike Faulkenberry / Jody Morehouse
Phase	Planning
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

Within the natural gas distribution system of all three states, there are sections of gas pipelines that are located above grade. Some of these sites are no longer compliant with current safety codes and design practices, or the support structures are failing. Like other areas of the gas and electric system, over the years construction practices have changed due to stricter standards and improved construction methods. As a result, these above grade crossings have a variety of construction techniques and supporting structures with varying degrees of risk associated with each of them.

This Business Case addresses capital expenditures associated with remediating these sites. Each location will be unique in how it is his corrected and the costs will vary depending on the complexity of the project. Resolution will typically involve either installing new pipe below grade using a horizontal directional drill (HDD) method or rebuilding the existing crossing. There are times when the best solution will be classified as an expense (O&M), in those cases this program will help risk rank those sites and work with the District Manager to get the work completed under their O&M plans.

There are several issues that typical of these sites that needs to be addressed, all of these cause Avista to be out of compliance with federal safety standards. The pipe wrap may have failed or deteriorated to the point of no longer being effective. The support hangers may be dislodged from their support structure (normally a bridge). The support hangers may be the style that do not allow a complete inspection for atmospheric corrosion. The pipe may have active atmospheric corrosion. The support structure may be failing, and no longer able to provide adequate support for the gas pipe. Warning signs may be missing.

The Oregon PUC has recently delivered to Avista a Notice of Probably Violation (NOPV) for a bridge crossing in Roseburg, Oregon in their 2021 safety audit that requires action on the part Avista to remediate. If we have this program approved and in place, this will show to the PUC that Avista recognizes the shortcomings and has a plan to address them.

In 2019, Gas Engineering reviewed all known above grade pipe in the state of Oregon by visiting each site, taking pictures, evaluating the condition of the pipe, coating, and support structures, assessing the area for possible remediation options, and then finally using a risk scoring matrix developed with Gas Integrity to risk rank all 162 sites. Of these sites, 34 of them were classified as high risk, requiring remediation. The plan will be to do a similar review of the above grade pipe in both Washington and Idaho in 2022. That data will then be added to the existing evaluation matrix, which will be used to determine the project list for each year. Based on subject matter experts, it is expected that we will have far fewer sites in Washington and Idaho to remediate then we do in Oregon.

Aboveground piping is required to be inspected once every three years for atmospheric corrosion per CFR 192.481. To properly inspect for corrosion, the entirety of the pipe must be available for visible assessment. Some legacy sites have pipe that is installed in a manner that makes it impossible to do a proper inspection. This program will address this deficiency.

Gas mains in places or on structures with the potential for physical movement (i.e. bridges) must be patrolled 4 times a year in business districts and 2 times a year outside of business districts per CFR 192.721. The intent of these patrols is to look for sound structures and hanging supports. Some of the sites on the list have hanger systems that are failing due to corrosion or concrete deterioration, resulting in improper support of gas pipes. This program will address these deficiencies also.

It is recommended to spend $750,000 per year mitigating these crossings. This will fund one large HDD project, or several medium to small sized projects per year. This mitigation work will ensure our gas pipeline facilities are operating with reduced risk, creating a safe and reliable system for our communities and customers. If this program is not started, Avista will be at risk of:

- fines from the State PUC's for being out of compliance with federal safety codes,
- pipeline failures if support structures fail,
- environmental fines if a pipeline failure results in a release of gas, and
- temporary loss of service to downstream gas customers.

If the site is remediated by installing the pipe below grade, Avista reduces the O&M expense of the once every three-year atmospheric corrosion inspection and the quarterly bridge inspection. Additionally, the Distribution Integrity Management Program (DIMP) will assess a lower risk score since below grade installation have much less of a chance of being damaged by an earthquake, flood, or vehicle incident.

Some of this remediation work is occurring already on a smaller scale under the Gas Non-Revenue Business Case. Specifically, some above grade gas services in the Spokane area have been identified and are being remediated over the next three years. If this Business Case is approved, that category of work will be transferred to this program, prioritized, and completed as required.

1.1 What is the current or potential problem that is being addressed?

Above grade gas pipeline crossings that are not in compliance with federal safety codes or have been deemed high risk through a risk evaluation performed by Gas Engineering and Gas Integrity.

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 major driver is Mandatory & Compliance. This remediation is necessary to stay in compliance with CFR 192 safety codes. Customer Service Quality & Reliability and Asset Condition are additional drivers for remediating high risk above grade piping.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This work is necessary now because we currently have pipeline crossings that are not in compliance, are at risk of failing, and are at risk of fines from State PUC Safety Departments.

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.

Success can be measured by a reduction in the number of sites in need of remediation from the original 34 on the current risk matrix.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The assessment work conducted by Gas Engineering in 2019 is all stored on the corporate network drive: c01d44\GASENGINEER\GAS DESIGN DOCUMENTATION\Engineer Documentation\Heidi Plough\Oregon Above Ground Crossings

2. PROPOSAL AND RECOMMENDED SOLUTION

It is proposed to spend $750,000 per year mitigating these crossings. This will fund one large HDD project, or several medium to small sized projects per year. This mitigation work will ensure our gas pipeline facilities are operating with reduced risk, creating a safe and reliable system for our communities and customers. If this program is not started, Avista will be at risk of:

- fines from the State PUC’s for being out of compliance with federal safety codes,
- pipeline failures if support structures fail,
- environmental fines if a pipeline failure results in a release of gas, and
- temporary loss of service to downstream gas customers.

If the program is funded at a lower level, then the risk to the gas system and our customers will be reduced at a slower pace. The “Do Nothing” option is not a good approach to this Business Case since we are currently aware of existing defeciencies on our system (listed above) and have identified parts of the system that are in need of remediation to meet current federal safety codes.

Option	Capital Cost	Start	Complete
Remediate at a level of $750k/year	$750,000	01 2022	TBD
Remediate at a level of $500k/year	$500,000	01 2022	TBD

Do Nothing	$0	MM YYYY	MM YYYY

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

In 2019, Gas Engineering reviewed all known above grade pipe in the state of Oregon by visiting each site, taking pictures, evaluating the condition of the pipe, coating and support structures, assessing the area for possible remediation options, and then finally using a risk scoring matrix developed with Gas Integrity to risk rank all 162 sites. 34 of the sites were classified as high risk, requiring remediation.

The Oregon PUC has recently delivered to Avista a Notice of Probably Violation (NOPV) for a bridge crossing in Roseburg, Oregon in their 2021 safety audit that requires action on the part Avista to remediate. If we have this program approved and in place, this will show to the PUC that Avista recognizes the shortcomings and has a plan to address them.

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.

Capital spend will go directly toward bringing above grade crossings that need remediation up to current federal safety codes. As described above, if the remediation project will install the pipe below grade, then the once every three-year atmospheric corrosion inspections and the quarterly bridge inspections will no longer be required, resulting in yearly O&M reductions.

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 program will be administered and monitored by Gas Engineering. It will require assistance from the local Operation Districts to coordinate and complete the work.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Since the identified above grade pipe that is in need of remediation does not currently meet federal safety codes, the only way to address this risk is to remediate each of the crossings. Each location is unique and will be analyzed to determine the best remediation approach. The lower funding alternative option slows the pace of remediation and the resultant reduction of known risk in the system. The do nothing approach results in no risk reduction, and leads to additional risk to Avista, including:

- fines from the State PUC's for being out of compliance with federal safety codes,
- pipeline failures if support structures fail,
- environmental fines if a pipeline failure results in a release of gas, and
- temporary loss of service to downstream gas customers.

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 will be started each year, and in most cases will be complete within a year of beginning. Some sites may require unique permitting or specialty equipment that may extend that project timeline beyond a year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Avista has a Value of being Trustworthy, that means we do what’s right. The right thing to do is take care of the pipeline facilities, make them as reliable as possible, keep the public safe, and ensure our facilities are not out of compliance.

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

A funding level of $750,000 for the first several years will get this program underway. At this level, the current staffing of Engineers is adequate to support the program without having to contract out any of the design work. On an annual basis, this program will be compared to other Gas Programs to ensure the company is focusing on our highest risk areas.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Gas Engineering, District Operations support individuals (CPC’s and Inspectors), Contracts, and Drafting are the main groups impacted by this program.

2.8.2 Identify any related Business Cases

None.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

This program will be administered by an Engineer within Gas Engineering. The program’s spend and budget will be reviewed monthly by the Gas Engineering Prioritization Investment Committee (EPIC). The Engineer will ensure the highest risk projects are completed first.

3.2 Provide and discuss the governance processes and people that will provide oversight

The manager of Gas Engineering will provide oversight to the program.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Monthly budget changes will be documented via the existing CPG process, approved by the Manager of Gas Engineering and the Director of Natural Gas. The monthly Gas EPIC updates are captured via email.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Above Grade Pipe Remediation 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: Date: 7/8/21
Print Name: Jeff Webb
Title: Mgr Gas Engineering
Role: Business Case Owner

Signature: Mike Faulkenberry Date: 7/9/21
Print Name: Mike Faulkenberry
Title: Director of Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Gas Transient Voltage Mitigation Program, ER 3010

EXECUTIVE SUMMARY

Avista has experienced safety issues including fires at Regulator Stations due to transient voltage spikes from faults on the adjacent electric transmission system. The purpose of this program will be 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 to both these scenarios on the pipelines. These efforts will protect the pipeline and equipment from being damaged and reduce the touch voltage exposure to below compliance limits, keeping our employees safe. Common approaches to this include the installation of gradient mats, solid state decouplers (SSD), and copper counterpoise conductor.

5 Yr Plan:

Year	**Requested Amount**
2022	$900,000
2023	$1,000,000
2024	$250,000
2025	$250,000
2026	$250,000

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeff Webb / Tm Harding	Initial Version	12/17/21	

Gas Transient Voltage Mitigation Program, ER 3010

GENERAL INFORMATION

Requested Spend Amount	$900,000
Requested Spend Time Period	5-10 years
Requesting Organization/Department	B51 / Gas Engineering
Business Case Owner | Sponsor	Jeff Webb / Tim Harding | Jody Morehouse
Sponsor Organization/Department	G51 / Director Natural Gas
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Electric transmission and distribution lines are inducing hazardous levels of AC voltage on nearby steel gas pipes. These high voltage levels can damage equipment and are a shock hazard to employees, contractors, and the general public.

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 business case is Mandatory & Compliance. As described below, there are several industry standards that dictate safe voltage levels on gas systems. Our current systems are not compliant, creating safety and system integrity concerns.

Additionally, there is benefits to both the customer and the general public in the reduced instance of hazardous voltage levels on above-ground gas facilities. Many of these facilities out in the open and can be contacted by the public.

The industry documents used for this analysis are based on the NACE International Standard Practice SP0177-2014, “Mitigation of Alternating Current Lightning Effects on Metallic Structures and Corrosion Control Systems”. The NACE standard covering AC corrosion is SP21424-2018,” Alternating Current Corrosion on Cathodically Protected Pipelines: Risk Assessment, Mitigation, and Monitoring.” The principal personnel safety guidelines during faults used for this analysis are based on IEEE Std 80-2013 “IEEE Guide for Safety in AC Substation Grounding”. While IEEE Std 80-2013 is primarily focused on substations, the guidelines can be applied to touch and step voltage locations as part of AC interference analysis.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

In the last five years there have been multiple (5+) equipment failures due to electric fault incidents. Some of these incidents caused fires and equipment damage. In all cases, hazardous voltages where present on the piping system that could have seriously injured someone in contact with the system.

If this program is not funded, then the steel pipe may be carrying high levels of AC voltage, causing an unsafe work environment for Avista employees and a there is a high likelihood of equipment failures.

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.

Hazardous pipeline voltages are seen in two forms: Steady state voltage, and fault voltage. Steady state voltages are present at all times. After mitigation equipment is installed, the reduction in steady state voltages can be immediately observed, and the effectiveness of the mitigation system can be determined. Fault voltages only occur during electric system faults and they are present for a fraction of a second. With current technology available, these voltages are never observed at the time of the incident, only estimated after an incident. We do not intentionally induce these voltages for testing purposes, so it is more difficult to directly measure the effectiveness of these mitigation efforts. Over time, a reduction in fault damage will be noted on the system after the mitigation work is completed.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

To date, two formal studies have been conducted by two different consulting firms, and the third is in process. Each study is site-specific and requires both field measurements and a software-based analysis. The outcome of these studies are mitigation designs that put the system into compliance with the previously listed standards.

In 2022 the area of focus will be the Rathdrum Prairie area of Idaho. A consultant is currently under contract (2021) to study the area and to recommend specific actions Avista should take to ensure the steel pipe in the area is safe to work on. This program will then look at other high pressure pipeline systems, assess the need for mitigation, and install measures as required.

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.

n/a

2. PROPOSAL AND RECOMMENDED SOLUTION

The installation of mitigation equipment to address hazardous pipeline voltages is an industry standard practice. These systems are either installed as part of a new pipeline project, or retrofit at a later time when the hazard is discovered. Avista is currently using temporary grounding equipment when construction and maintenance work is required on these system. This temporary equipment is time consuming to set up and requires ongoing training to use correctly. The equipment is not left on the system and therefore does not protect the general public or contractors (such as locators) from unsafe voltages.

If this program is not funded, then the steel pipe may be carrying high levels of AC voltage, causing an unsafe work environment for Avista employees and a chance for equipment failure.

Option	Capital Cost	Start	Complete
Install AC Mitigation Equipment	$2.65M	01 2022	12 2026

Use Temporary Grounding Equipment	$0	01 2022	12 2026

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The capital request was based on the execution of recent mitigation projects, carried out under a different budget. This program is needed to comply with pipeline safety standards. Gas Operations is using temporary measures so they can continue with required construction and maintenance activities. These temporary measures are not widely used in the industry and are absolutely not intended to be used as long term solutions to high voltage hazards.

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 budget will be spent on system design studies, followed by the installation of mitigation systems. The installation of these systems will result in a small reduction in O&M spending because temporary grounding systems will not be needed during annual regulator station maintenance.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

Maintenance and construction activities on mitigated pipeline systems will be eased because temporary grounding systems will not be required each time the system is approached. The mitigation equipment has an impact on the ability to test the performance of cathodic protection (CP) systems. Additional effort and equipment is needed to perform CP testing with the mitigation equipment in place.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Safety measures are now in place in areas with known voltage hazards. These measures include using temporary grounding systems when personnel are working on gas facilities. Using these systems is time consuming and requires training. These systems are not in place at all times and therefore the general public is not protected from shock hazards near these locations.

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.

Work on this effort is ongoing, having started in 2019 in Oregon. A new project in Idaho started in 2021. From the time of hazard identification, to design, and then mitigation equipment installation, the process takes approximately 18-24 months.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

This program addresses hazardous voltages on gas systems that were never intended to have AC voltage present. The installation of mitigation equipment reduces hazardous voltage levels, allowing the company to be compliant with industry standards. This reduces the chance of system damage, as well as the possibility of shock hazards to company personnel, contractors, and the general public.

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

The requested amount is prudent based on the long-term benefits to system integrity and personnel safety. Projects within the program will be prioritized based on the severity of the safety hazard and other factors. Prioritization will be ongoing regularly to ensure the highest risk projects are being addressed first.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Gas Operations: Customers being protected by new mitigation systems, as well as involved with mitigation installation projects.

Gas Engineering / Cathodic Protection Group: Responsible for overseeing the design and implementation of projects.

2.8.2 Identify any related Business Cases

ER 3004, Cathodic Protection Program

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The following people will be providing program input: Manager of Gas Design, Manager of Natural Gas Pipeline Integrity and Compliance, Cathodic Protection General Foreman, Corrosion Engineer

3.2 Provide and discuss the governance processes and people that will provide oversight

The above listed group will have input on the prioritization of individual mitigation projects. These projects will be ranked based on criteria that is currently being developed by this group.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

The Corrosion Engineer, acting as project manager, will meet quarterly with the above stakeholders to review program status and discuss project prioritization. Documents prepared for the meeting, as well as meeting minutes will serve as project communication and documentation.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Transient Voltage Mitigation 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.

Gas Transient Voltage Mitigation Program, ER 3010

Signature: Date: 12/17/21
Print Name: Jeff Webb
Title: Mgr Gas Engineering
Role: Business Case Owner

Signature: Date: 12/17/21
Print Name: Jody Morehouse
Title: Director Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Tribal Permits & Settlements

EXECUTIVE SUMMARY

This business case is driven by compliance – the legal requirement to obtain and maintain permits/leases for Avista's facilities located on Tribal reservations. Land ownership on Tribal reservations is complex. Much of the land is held in trust by the federal government on behalf of either Tribes or individual Tribal members. Permits for Avista's transmission and distribution facilities were originally obtained pursuant to 25 CFR 169. Business leases required for substations are obtained pursuant to 25 CFR 162. However, the federal regulations do not typically allow for perpetual easements. Rather, permits/leases can be issued up to 50 years and then these permits need to be renewed. The majority of Avista's permits have reached the 50 year expiration and need to be renewed. In addition, new facilities placed on Trust lands need new permits. In order to acquire a renewed or new permit, a time-consuming federal regulatory process needs to be followed and permission needs to be obtained from the Tribe and/or the majority of individual Tribal landowners who have an interest in the relevant parcel of land. The permit is issued by the Bureau of Indian Affairs after they determine all steps of the process have been achieved. Most of the land on Reservations is divided into parcels of 80 acres or less. Therefore, a transmission or distribution line usually crosses numerous parcels of land – each of which requires its own permit.

Avista has facilities on the following Tribal reservations: Spokane, Colville, Nez Perce, Coeur d'Alene, Flathead, and Kalispel trust lands in Airway Heights. Avista maintains approximately 82 miles of transmission lines on Tribal trust lands. Over the last 10 years, we have renewed permits on the Coeur d'Alene, Flathead, and Nez Perce reservations. The current focus is renewals on the Spokane and Colville Reservations. Approximately 300 new permits are needed on the Spokane Reservation and 130 on the Colville Reservation.

Failure to obtain necessary new permits and maintain existing permits would put us in immediate violation of Federal Law. Without a valid permit, the Bureau of Indian Affairs would require us to remove our facilities from Tribal trust lands. Avista has an obligation to serve its customers on these reservations. To ensure Avista can serve its customers and transmit power on and across Tribal reservations, we need to complete the process of renewing permits that have and/or are expiring.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Toni Pessemier*	*Initial draft of original business case*	*7/8/20*	
1.0		*Updated Approval Status*		*Full amount approved*
1.1		*Budget change*		
2.0				

Tribal Permits & Settlements

GENERAL INFORMATION

Requested Spend Amount	$1,250,000
Requested Spend Time Period	*5+ years*
Requesting Organization/Department	American Indian Relations
Business Case Owner | Sponsor	Toni Pessemier /Jason Thackston |
Sponsor Organization/Department	Energy Resources
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed? *Avista has a federal regulatory requirement to obtain and maintain permits/leases for its facilities located on Tribal reservations, specifically for the land held in trust by the Federal government on behalf of either Tribes or individual Tribal members ("trust lands"). Permits for Avista's transmission and distribution facilities were originally obtained from the Bureau of Indian Affairs pursuant to 25 CFR 169. Business leases required for substations are obtained from the BIA pursuant to 25 CFR 162. The Federal regulations do not allow for perpetual easements. Rather, permits/leases were issued up to 50 years. The majority of Avista's permits on Tribal reservations have reached the 50 year expiration and need to be renewed.*

1.2 Discuss the major drivers of the business case – *Mandatory and Compliance – Avista needs to obtain and maintain active permits for all of its encroachments on Trust lands on Tribal reservations. Avista has facilities on the following reservations: Spokane, Colville, Nez Perce, Coeur d'Alene, Flathead, and Kalispel trust lands in Airway Heights. Avista maintains approximately 82 miles of transmission lines on Trust lands and extensive distribution systems. To-date, we have renewed permits on the Nez Perce, Coeur d'Alene and Flathead reservations. Avista's current focus is to renew permits for facilities on the Spokane and Colville Reservations.*

Tribal Permits & Settlements

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred *Avista is the only electric provider on the Spokane Reservation and is the electric provider in the Inchelium area of the Colville Reservation. Avista has an obligation to serve its customers. Approximately 300 permits are needed on the Spokane Reservation and 130 on the Colville Reservation. To ensure Avista can continue to serve its customers, and transmit power to serve customers on and off the reservations, we need to continue the process of renewing permits that have and/or are expiring. Avista does not have the ability to condemn on Tribal trust lands. If Avista is not actively pursuing these renewals, we would be in violation of Federal law, and the Bureau of Indian Affairs could demand that we immediately remove our facilities from Tribal trust lands. There are examples across the United States where businesses have been required to remove their facilities when permits have expired. Although Avista has now renewed many of the transmission related permits for 20-50 years, it has been estimated that it would cost at least $61 million to relocate all transmission lines off of Tribal land. Because of our obligation to serve, we need to continue obtaining the required permits for distribution facilities on the reservations.*

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. *Over the last 10 years, Avista has successfully delivered on the objectives and renewed all of the expired permits for facilities on the Nez Perce, Coeur d'Alene and Flathead reservations so we have a successful track record and are extensively familiar with the process and estimated costs. However, each Tribe, reservation, and Tribal member is unique so costs can vary depending on individual negotiations and resolutions.*

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

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.

Continue the process to obtain renewed permits for Avista's facilities located on Trust lands on Tribal reservations which are required by law to transmit power and continue serving our customers. Relocating transmission lines would include longer distances and the risk of obtaining satisfactory easements on non-Tribal land. For distribution assets on Trust lands, there is no immediate viable option, due to obligation to serve.

Option	Capital Cost	Start	Complete
Continue to negotiate permits/leases as required	*250,000 annually*	*01 2021*	*12 2025*

Do nothing, - not in compliance with federal regulations and leads to next alternative	*$0*		
Relocate transmission lines off of Tribal land	*$61,190,000*	*01 2021*	*12 2023*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

The 250,000 is a placeholder for permitting costs which has run historically:

Project Description	**2017**	**2018**	**2019**
2015 CDA 230kV TransPermits	5,777	5,311	4,832
2015 Colville Tribe DistPermit	103,660	43,792	84,971
2015 CSKT 230kV Tran Permits	2,963	63,816	
2015 NezPerce 230kV T-Permits	(4,952)		
2015 Spokane Tribe DistPermits	62,870	73,911	77,144
2015 SpokaneTribe 115kV Permit	38,677	103,083	205,060
2016 ID Dist Tribal Permits	4,823		
2017 Nez Perce Dist Permits	177,710	39,944	26,256
2020 CDA 230kV TransPermits			502
2020 Colville Tribe DistPermit			14,961
2020 Nez Perce Dist Permits			2,228
2020 Spokane Tribe DistPermits			2,919
Kamiah Nez Perce 115kV Easmt	23,491		
Grand Total	**415,020**	**329,857**	**418,873**

Costs can vary depending on the Tribe, Bureau of Indian Affairs personnel on the reservation, and individual Tribal members when trying to reach a settlement. Additionally the federal regulations were updated in 2017 and the costs associated with the renewal process (e,g, individual surveys, appraisal reports, process to obtain consent from landowners) have the potential to increase.

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 costs are associated with following 25 CFR 169 and 162 regulatory processes, and negotiating settlements with Tribe and/or individual Tribal members as needed. The objective is to renew all of the remaining expiring permits. Avista maintains a Native American Relations department for the express purpose of working closely with Tribes on a variety of issues. The annual O&M expenditure for this department is approximately $300,000. The Tribal Rights of Way Specialist devotes 90% of her time to this capital business case.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

By renewing the permits, transmission and distribution engineering will not need to evaluate options and costs associated with relocating our facilities.

Operations staff will have rights for ingress and egress to maintain our facilities and service to customers will not be negatively impacted.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative. *See 2.0*

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. spend, and transfers to plant by year.

This work is ongoing. Transfer to plant is reviewed quarterly. When permits have been obtained, related costs can be transferred.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Being able to serve our customers is critical and our customers trust we will do so. Obtaining the required permits allows us to demonstrate our focus on compliance. Avista's commitment to Tribal relations demonstrates accomplishing this in a collaborative manner.

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 *Costs are directly associated with compliance and adhering to federal law and regulations 25 CFR 169 and 162. When settlement discussions are necessary to obtain a permit, each situation and scenario is evaluated for possible alternatives and related costs. In all cases to-date, the settlement costs have been lower than alternatives such as relocating facilities.*

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

2.8.2 Identify any related Business Cases

3.1 Steering Committee or Advisory Group Information

There is no specific Steering Committee for this Business Case. The Advisory

Group is the American Indian Relations department in consultation with others including the Realty Department, Legal, District Managers, Transmission and Distribution Engineers as needed.

3.2 Provide and discuss the governance processes and people that will provide oversight *American Indian Relations department is responsible for day to day activities. The Tribal R/W specialist works with other Real Estate representatives and utilizes multiple systems. The Sr. VP of Energy Resources provides oversight along with VP General Counsel and VP Chief Regulatory Counsel.*

3.3 How will decision-making, prioritization, and change requests be documented and monitored *Decision making will occur as outlined in 3.2. Change requests and documentation will be initiated and monitored by American Indian Relations with support from Financial Planning & Analysis Operations Analytics Manager.*

The undersigned acknowledge they have reviewed the *Tribal Permits and Settlements 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: Toni Pessemier Date: 7/9/20
Print Name: Toni Pessemier
Title: American Indian Relations Advisor
Role: Business Case Owner

Signature: Jason Thackston Date: 7/10/20
Print Name: Jason Thackston
Title: Sr. VP Energy Resources
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

Tribal Permits & Settlements

Template Version: 05/28/2020

Gas Airway Heights HP Reinforcement, ER3312

1 GENERAL INFORMATION

Requested Spend Amount	$7,000,000
Requesting Organization/Department	B51
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Planning department routinely runs an analysis (load study) on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve existing Firm customer loads on a design day (Avista defines design day as the projected system demand for a "coldest day on record" weather event). These deficient areas are given a priority level based on the severity of the risk associated with insufficient system capacity. The areas with the highest priority are selected for remediation and the project is assigned to Gas Engineering to evaluate options to provide sufficient capacity to meet Firm gas demands on a design day. Options are reviewed with Gas Planning, Gas Operations, and other impacted parties. The pros and cons of each option are then reviewed with the Gas Engineering Manager and a preferred alternative is selected to proceed with a funding request.

2 BUSINESS PROBLEM

Load studies performed by the Gas Planning department as well as pressure monitoring during cold weather events has shown that there is insufficient pressure at the west end of the Fairchild-Spokane High Pressure (HP) Main. This HP main supplies gas to the Airway Height, Spokane Airport, and SW area of Spokane. This deficiency is expected to start during the winter of 2019-2020.

Sufficient capacity is defined as pressures at or above 15 psig in the distribution system and 90 psig on the HP system on a design day analysis. Without a reinforcement project, Avista will not have sufficient capacity to serve the firm customers in these areas on a design day scenario. In addition, Airway Heights is the fastest growing area in Spokane County.

Space heating is the most predominate use of gas for Avista's firm customers. Should a gas outage occur during a cold weather event due to insufficient capacity of a distribution system, there would be a high level of risk associated with the health and safety of the individuals, and the potential damage to the buildings due to freezing water pipes. Completion of this reinforcement project greatly reduces this risk.

Since this area has insufficient capacity to serve firm customers on a design day, a cold weather action plan has been developed. This plan outlines particular activities that could be implemented such as the manual on-sight monitoring of system pressures, a media blast to request a temporary thermostat turndown, taking extraordinary measures to manually improve the capacity of the system by bypassing regulator stations or manually shedding load (shutting off customers completely), and/or preparing relight lists (to restore service to customers who have lost gas service).

Avista has determined it is not appropriate to rely upon a cold weather action plan for the safe and reliable operation of the natural gas distribution system. These are stop gap measures put in place because of a known capacity deficiency until a permanent reinforcement project can be completed. Operating in this mode requires Avista employees to work outdoors in extremely cold situations, which results in increased operations and maintenance expense (O&M expense) due to overtime pay and increased safety risks to our employees performing the manual intervention (i.e., working outdoors and driving vehicles in cold, snowy, and icy conditions). Additionally, these activities are last-ditch efforts to maintain service, and they do not represent a guarantee that service will be able to be maintained to customers paying a firm gas rate.

Additional efforts will be spent in 2020 to determine the best solutions with construction scheduled to start in 2021.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Opt. 1 - Do nothing	$0		
Opt. 2 - Recommended Solution - Install approximately 20,000' of HP main to reinforce the system	$7,000,000	04 2020	11 2022
Opt. 3 - Alternative #1 – Uprate the 8" HP line and rebuild the Spokane West Gate Station	$2,000,000 (~$100,000 O&M)	04 2020	11 2021
Opt 4 - Alternative #3 - Install approximately 16,000' of HP main and a new Gate Station in North Airway Heights	$8,000,000	04 2020	11 2022

Option 1 – Do Nothing

Without a reinforcement project, Avista does not have sufficient capacity to meet its obligation to serve Firm customer loads in the Spokane/Airway Heights area on a design day scenario. See Image 1 for a load study analysis showing the HP system with insufficient capacity to serve existing customers. Doing nothing would put the company at a high risk of outages. Additionally there is no available capacity for future customers interested in commercial ventures in the area.

It is important to note that if service is lost during severe cold weather, gas service may not become available again until weather warms and customer demand decreases. Depending on the length of the outage, this can cause severe injury up to and including death to some customers.

Option 2 – Install 20,000' of HP main

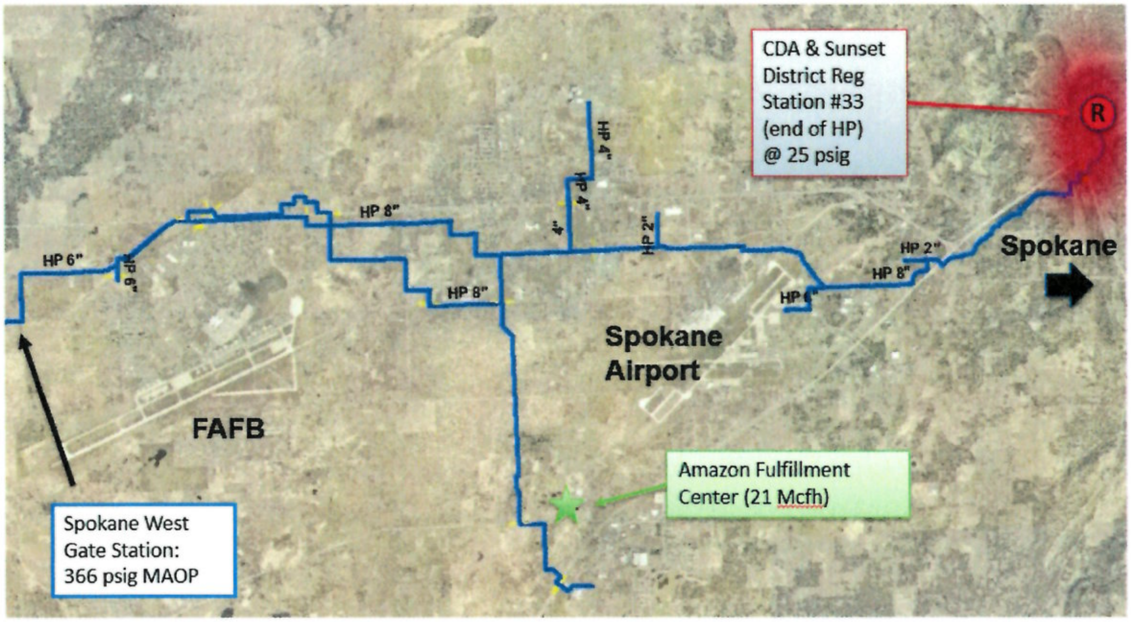
This option would provide the most traditional solution to the problem. By looping the HP line, there is a small amount of reliability and flexibility that is added to the system. Depending on the route chosen, this option may allow some flexibility to the project by allowing it to be compressed into one year or phased over two years, and either option would realize a gain in capacity at the end of the construction season each year. Image 2 shows the proposed pipeline route and the positive impacts to the system.

Option 3 - Uprate the 8" HP line and rebuild the Spokane West Gate Station

This option would uprate the 8" HP line constructed in 2000 from 366 psig to 500 psig. This would also likely require a complete rebuild of the gate station. Uprating the HP line may involve O&M funds. This option may also lead to operational issue such as icing at regulator stations due to the higher inlet pressures.

Option 4 - Alternative #3 - Install approximately 16,000' of HP main and a new Gate Station in North Airway Heights

This option would create another feed into the HP system, which would add reliability. No new customers would likely get added as the HP main would go through areas already served with intermediate pressure main.



CDA & Sunset District Reg Station #33 (end of HP) @ 25 psig

Amazon Fulfillment Center (21 Mcfh)

Spokane West Gate Station: 366 psig MAOP

Image 1 – HP System as is, end of HP system at 25 psig

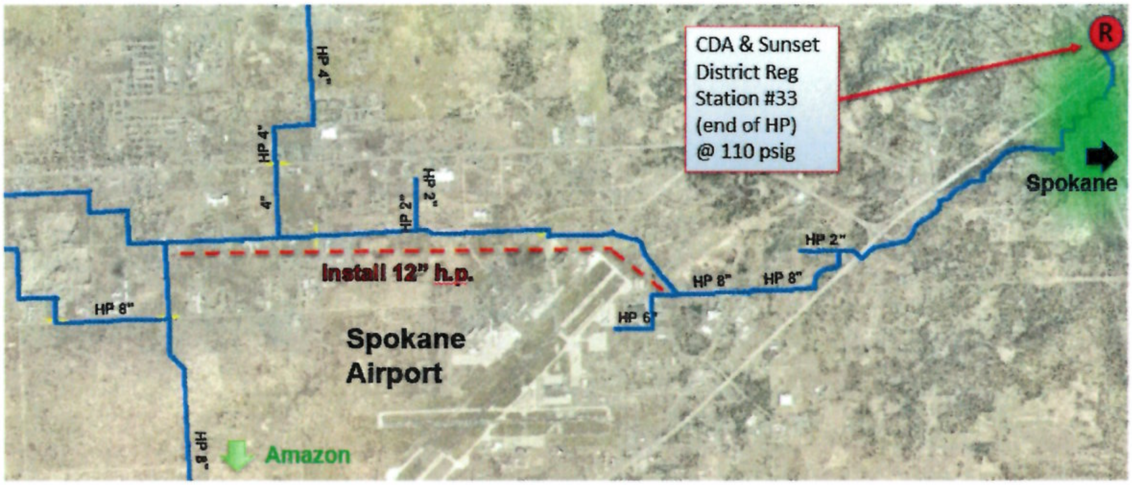


Image 2 – HP System with 20,000' reinforcement, end of HP system at 110 psig

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Airway Heights HP Reinforcement 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: Date: 7-8-19
Print Name: Jeff Webb
Title: Mgr Gas Engineering
Role: Business Case Owner

Signature: Date: 7/8/19
Print Name: Mike Faulkenberry
Title: Director Natural Gas
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*<Author name>*	*mm/dd/yy*	*<name>*	*mm/dd/yy*	*Initial version*

Template Version: 03/07/2017

Gas Pullman HP Reinforcement Project, ER 3309

1 GENERAL INFORMATION

Requested Spend Amount	$2,500,000 (2020)
Requesting Organization/Department	B51 – Gas Engineering
Business Case Owner	Jeff Webb
Business Case Sponsor	Mike Faulkenberry
Sponsor Organization/Department	B51 – Gas Engineering
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

The Gas Planning department routinely runs an analysis (load study) on Avista's gas distribution system to identify areas of the system with insufficient capacity to serve existing Firm customer loads on a design day (Avista defines design day as the projected system demand for a "coldest day on record" weather event). These deficient areas are given a priority level based on the severity of the risk associated with insufficient system capacity. The areas with the highest priority are selected for remediation and the project is assigned to Gas Engineering to evaluate options to provide sufficient capacity to meet Firm gas demands on a design day. Options are reviewed with Gas Planning, Gas Operations, and other interested parties. The pros and cons of each option are then reviewed with the Gas Engineering Manager and a preferred alternative is selected to proceed with a funding request.

2 BUSINESS PROBLEM

Based on load studies performed by the Gas Planning department, the load growth in the Pullman, WA area has exceeded the capacity of the existing Pullman Gate Station (supply point into Avista's system). This impacts Avista's obligation to serve Firm customers on a design day. The contracted capacity at the Pullman Gate Station is 786 thousand cubic feet per hour (Mcfh) and the projected Firm load on a design day is 916 Mcfh. This difference puts approximately 1,300 customers at risk of losing gas service.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 – Do nothing	$0		
Option 2 – Preferred Solution, Install of 3 miles of High Pressure pipe from Moscow Gate Station	$2,500,000	06 2019	12 2020
Option 3 – Alternative Solution, Rebuild the Pullman Gate Station	$ TBD	06 2019	12 2020

Option 1 – Do nothing

Without a reinforcement project Avista does not have sufficient capacity to meet its obligation to serve existing Firm customer load in the Pullman, WA on a design day scenario, and is not able to support future customer growth. See Image 1 below for a graph showing the Expected Load vs Contracted Capacity. Approximately 1,300 customers are at risk of losing their gas service during a cold weather event.

It is important to note that if service is lost during severe cold weather, gas service may not become available again until weather warms and customer demand decreases. Depending on the length of the outage, this can cause severe injury up to and including death to some customers.

Option 2 – Preferred Solution, Install 3 miles of High Pressure pipe from the Moscow Gate Station

The high pressure (HP) main from the Moscow Gate Station is approximately three miles from the HP main that is fed from the Pullman Gate Station. By installing main between the two systems the loads would be balanced and station capacities better utilized. This option will add reliability by creating a looped system (bringing a second source to an area) and will provide additional growth opportunities along the way for individuals currently without gas service.

Option 3 – Alternative Solution, Rebuild the Pullman Gate Station

A rebuild of the Pullman gate station would address the capacity constraints but would not add any reliability to the system nor any new growth opportunities. The cost of this project, based off of similar recent work, would be comparable in cost to Option 2.

Additional efforts will be spent in 2019 to develop the alternate solutions and confirm that Option 2 is still the preferred solution.

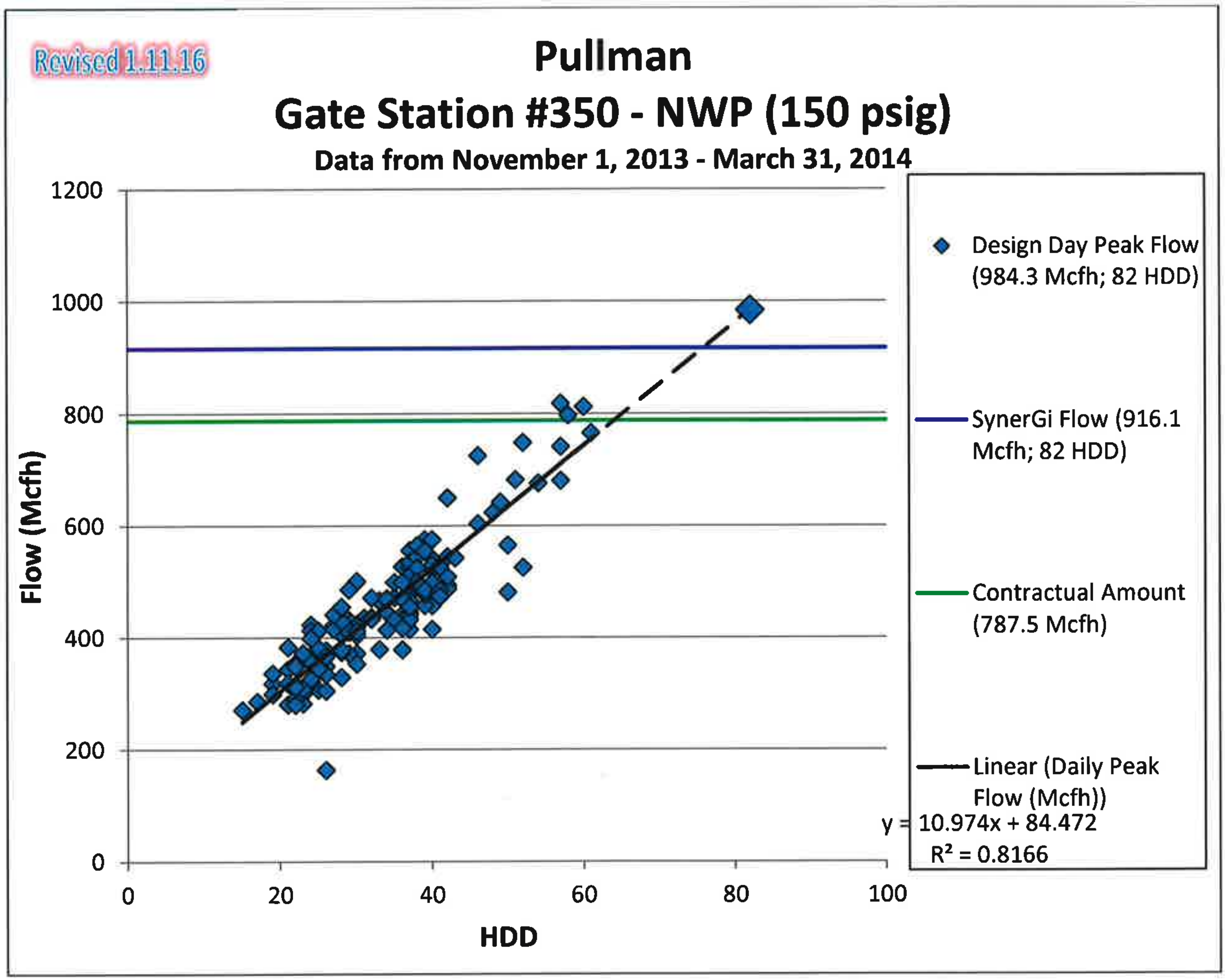


Image 1 – Expected Load vs. Contracted Capacity

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Gas Pullman HP Reinforcement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 4-17-17

Print Name: Jeff Webb

Title: Manager Gas Engineering

Role: Business Case Owner

Signature:

Print Name: Mike Faulkenberry

Title: Director of Natural Gas

Role: Business Case Sponsor

Date: 4/17/17

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Jeff Webb	04/17/2017	Mike Faulkenberry	04/17/2017	Initial version

Template Version: 03/07/2017

Transmission Performance & Capacity

EXECUTIVE SUMMARY

The Transmission Performance & Capacity Business Case covers the Transmission new construction work necessary to either support the addition of new substations due to load growth in a particular area or to reinforce existing substations with new transmission for increased performance. This program is managed through the joint efforts of Avista's Transmission Design & Engineering, Substations, Operations, and Transmission Planning groups, from which the requests for upgrades or additions are initiated. The projects within this program are typically requested by System Planning or System Operations.

The implementation of this business case will be considered successful if these projects are completed when committed to, successfully coordinated with the corresponding substation projects if applicable, and result in increased capacity or reliability to Avista's customers in the local areas where projects are constructed.

The recommended solution is to construct new transmission lines as prioritized by the Engineering Roundtable group to ensure that there is sufficient capacity to serve new customers in growing areas and to increase reliability to existing substations that currently are served by underperforming transmission line configurations. There are no expected business impacts to continuing this program in place. If Avista does not implement this business case, the company is at risk of overloading its existing infrastructure in certain areas of its service territory where load is growing over time. This Program will have a Service Code of Electric Direct and a Rate Jurisdiction of Allocated North. A spend of $10,950,000 (2022-2028) to complete both projects, or $8,750,000 (2022-2026) is needed to complete one project and intitiate the other project as follows:

- *ER 2480, BI CT910 ($8,500,000): Carlin Bay Substation 115kV Transmission Integration*
- *ER 2612, BI ST907 ($2,450,000): Hawthorne Substation 115kV Transmission Integration*
    - *($250,000 in 2026)*

Note: This Business Case was previously known as Transmission New Construction – Performance & Capacity
Note: This Business Case is connected to the Substation Performance & Capacity Business Case

The customer benefits from this Business Case through increased service reliability.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Daisy Drafter*	*Initial draft of original business case*	*4/15/2020*	
1.0	*Prudent Penny*	*Updated Approval Status*	*6/1/2020*	*Full amount approved*
1.1	*Debbie Downer*	*Budget change*	*10/15/20*	*$50,000 deferred to 2021*
2.0				

Transmission Performance & Capacity

GENERAL INFORMATION

Requested Spend Amount	$8,750,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	TLD Engineering
Business Case Owner | Sponsor	Josh DiLuciano/Heather Rosentrater
Sponsor Organization/Department	Energy Delivery/Electrical Engineering
Phase	Planning
Category	Program
Driver	Performance & Capacity

1. BUSINESS PROBLEM

The Transmission Performance & Capacity Business Case covers the Transmission new construction work necessary to either support the addition of new substations due to load growth in a particular area or to reinforce existing substations with new transmission for increased performance. The projects within this program are typically requested by System Planning or System Operations.

1.1 What is the current or potential problem that is being addressed? *Avoidance of overloading existing infastructure due to continual load growth or operational restrictions.*

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** *Performance & Capacity: Customer benefits by having a Transmission System capable of supporting Substation Transformation additions needed to service growing loads.*

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred *Adding Substations and associated Transmission is based on forecasted load increases. These forecasts can either overshoot or undershoot actual conditions. It is therefore necessary that a structured and measured approach be made to adding this infastructure so as not to overtax budget, design and construction, and outage resources.*

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 implementation of this business case will be considered successful if these projects are completed when committed to, successfully coordinated with the corresponding substation projects if applicable, and result in increased capacity or reliability to Avista's customers in the local areas where projects are constructed. Typical Project Management tracking tools in regards to schedule and budget will be employed, as well as construction inspection services.*

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

ERT Form for Carlin Bay-Ogara New Transmission Line
ERT Form for Hawthorne Substation New Transmission Line

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 Business Case is associated with new assets.

2. PROPOSAL AND RECOMMENDED SOLUTION

This is the continuation of an ongoing Program, and requires the addition of infastructure to support load growth. Please see Alternatives Evaluation within each ERT submitted document for details.

Option	Capital Cost	Start	Complete
Add Infastructure	*$8.75M*	*01-2022*	*12-2026*
[Alternative #1]	*$M*	*MM YYYY*	*MM YYYY*
[Alternative #2]	*$M*	*MM YYYY*	*MM YYYY*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Examples include:

- *Samples of savings, benefits or risk avoidance estimates*
- *Description of how benefits to customers are being measured*
- *Comparison of cost ($) to benefit (value)*
- *Evidence of spend amount to anticipated return*

Reference key points from external documentation, list any addendums, attachments etc.

The benefits of this Business Case are seen in being able to support the Substation Performance & Capacity Business Cases in a timely and cost effective manner. Please see Substation Performance & Capacity Business Case Justification Narrative for details.

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 two projects referenced in this Justification Narrative are typically mult-year in nature with the first year consisting of design, real estate acquisition, environmental permitting, and some material acquisitions. The second year normally consists of material acquisitions, construction, As-builting, and project close-out. For very large projects the duration can extend to three years or more.

[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.

Primary impacts are in the area of obtaining Transmission system outages and construction resources. Although Transmission Line Design has the ability to Contract for construction services on the large projects, internal construction resources typically perform the smaller jobs. Design resources can be supplemented by local consulting services.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

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.

The two projects reference in this Justification Narrative are scheduled for the 2022-2024 time frame and complete construction in the 2026-2028 time frame.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Aligns with the Focus Areas of Customers and Perform.

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

Design solutions performed within PLS-CADD, which is the industry leader in providing Transmission Line Design computer based programs. Designs are reviewed at multiple stages to ensure prudency and maximum Stakeholder value.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Many and varied throughout Avista.

2.8.2 Identify any related Business Cases

Substation Performance & Capacity.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Electrical Engineering Expected Spend Committee reviews on a monthly basis ongoing spend for projects approved by the ERT. Committee members include Managers, Project Managers, analysts, and the Electrical Engineering Director.

3.2 Provide and discuss the governance processes and people that will provide oversight

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

During the design phase these functions are processed through the Engineering Roundtable. During large project Contracted construction, Change Orders are processed through Supply Chain. On smaller in-house construction projects, changes are agreed upon at the Project Eneginer/Project Manager, and are documented in the As-Built process.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Transmission Performance & Capacity Business Case Justification Narrative* 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: APPROVED
By Ken Sweigart at 7:41 am, Jan 04, 2022
Date:
Print Name:
Title:
Role: Business Case Owner

Signature:
Date: 1/4/2022
Print Name: Josh DiLuciano
Title: Director of Electrical Engineering
Role: Business Case Sponsor

Signature:
Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review