Exh. AGA-2

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DOCKET UG-240007

DIRECT TESTIMONY OF

ALEXIS G. ALEXANDER

REPRESENTING AVISTA CORPORATION

Proforma Capital Additions for 07.2023 - 12.2023 and 2024 by Plant Category
Alexander

WA GRC Plant Category	Project #	Business Case		07.2023-12.2023 TTP (System)	2024 TTP (System)	Exh. AGA-2 Page #
Large or Distinct Projects	1	Cabinet Gorge Station Service		$ 5,140,107	$ -	3
	2	Cabinet Gorge Stop Log Replacement		$ 1,196,523	$ -	13
	3	Cabinet Gorge Unwatering Pumps		$ 383,000	$ -	21
	4	Generation DC Supplied System Update		$ 356,240	$ -	27
	5	Generation Masonry Building Rehabilitation		$ -	$ 490,303	34
	6	KF 4160 V Station Service Replacement		$ -	$ 1,134,952	43
	7	KF Secondary Superheater Replacement		$ -	$ 99,888	50
	8	KF_Fuel Yard Equipment Replacement		$ 407,496	$ -	60
	9	KF_ID Fan & Motor Replacement		$ -	$ 2,008,437	72
	10	Little Falls Crane Pad & Barge Landing		$ -	$ 498,893	81
	11	Little Falls Plant Upgrade		$ 168,091	$ -	87
	12	Long Lake Plant Upgrade		$ -	$ 500,000	94
	13	Monroe Street Abandoned Penstock Stabilization		$ 749,999	$ 747,811	109
	14	Nine Mile Powerhouse Roof Replacement		$ 854,052	$ 1,312,654	119
	15	Nine Mile Unit 3 Mechanical Overhaul		$ -	$ 5,554,098	126
	16	Noxon Rapids Spillgate Refurbishment		$ 3,700,000	$ 194,036	136
	17	Noxon Rapids Unit 2 Generator Rewind		$ -	$ 299,321	144
	18	Peaking Generation Business Case	[3]	$ 332,169	$ 285,728	155
	19	Post Street Substation Crane Rehab		$ -	$ 1,614,227	165
	20	Upper Falls Trash Rake Replacement		$ 1,448,672	$ 185,540	175
Large or Distinct Projects Total				$ 14,736,435	$ 14,925,888	
Mandatory & Compliance	21	Cabinet Gorge Dam Fishway		$ 158,008	$ 600,000	185
	22	Clark Fork Settlement Agreement		$ 4,621,099	$ 3,027,380	193
	23	KF_Ash Landfill Expansion		$ 13,092	$ -	201
	24	Long Lake Stability Enhancement		$ -	$ 1,000,000	212
	25	Operational Safety and Compliance	[3]	$ -	$ 637,698	222
	26	Right-of-Way Use Permits		$ 122,160	$ 250,002	230
	27	Spokane River License Implementation		$ 1,453,808	$ 838,800	236
	28	WSDOT Franchises		$ 284,150	$ 150,000	243
Mandatory & Compliance Total				$ 6,652,317	$ 6,503,880	
Programs	29	Asset Lifecycle Management	[3]	$ -	$ 868,123	250
	30	Asset Monitoring System	[3]	$ 248,731	$ -	258
	31	Automation Replacement	[3]	$ 400,000	$ 588,220	263
	32	Base Load Hydro	[3]	$ 861,783	$ 461,474	272
	33	Base Load Thermal Program	[3]	$ 1,673,666	$ -	282
	34	Operational Sustainment	[3]	$ -	$ 7,976,356	293
	35	Regulating Hydro	[3]	$ 2,434,328	$ 703,845	301
Programs Total				$ 5,618,509	$ 10,598,018	
Short-Lived Assets	36	HMI Control Software		$ 4,016,838	$ 2,676,153	311
Short-Lived Assets Total				$ 4,016,838	$ 2,676,153	
Misc. accrual reversals, corrections or additional TTP				$ 80,511	$ 57,596	
Grand Total				**$ 31,104,523**	**$ 34,761,535**	

[1] Includes system profroma capital for the period July 1, 2023 through December 31, 2023.
[2] Totals exclude Idaho and Oregon direct business cases from revenue requirement in this case.
[3] Select Generation business cases are being consolidated into three programs based on driver: Operation Sustainment, Asset Lifecycle Management, and Operational Safety and Compliance. See Alexander Testimony.

Provisional Capital Additions for 2025-2026 by Plant Category
Alexander

WA GRC Plant Category	Project #	Business Case		2025 TTP (System)	2026 TTP (System)	Exh. AGA-2 Page #
Large or Distinct Projects	1	Cabinet Gorge Station Service		$ 11,259,147	$ -	3
	37	Coyote Springs 2 CT Rotor Replacement		$ 14,891,744	$ -	324
	5	Generation Masonry Building Rehabilitation		$ 232,932	$ -	34
	7	KF Secondary Superheater Replacement		$ 3,473,234	$ -	50
	12	Long Lake Plant Upgrade		$ 1,500,000	$ 45,000,000	94
	38	Nine Mile Units 3 & 4 Control Upgrade		$ 5,292,874	$ -	335
	39	Noxon Rapids Gantry Crane Modernization		$ -	$ 19,500,000	348
	40	Post Falls HED Redevelopment Program		$ -	$ 5,000,000	358
	41	Post Falls North Channel Spillway Rehabilitation		$ 5,000,000	$ 25,800,000	371
Large or Distinct Projects Total				$ 41,649,931	$ 95,300,000	
Mandatory & Compliance	21	Cabinet Gorge Dam Fishway		$ 399,879	$ 72,902	185
	22	Clark Fork Settlement Agreement		$ 2,663,700	$ 3,291,708	193
	23	KF_Ash Landfill Expansion		$ -	$ 11,076,524	201
	25	Operational Safety and Compliance	[3]	$ 1,967,828	$ 4,365,255	222
	26	Right-of-Way Use Permits		$ 250,000	$ 249,996	230
	27	Spokane River License Implementation		$ 954,600	$ 909,600	236
	28	WSDOT Franchises		$ 149,999	$ 150,000	243
Mandatory & Compliance Total				$ 6,386,006	$ 20,115,985	
Programs	29	Asset Lifecycle Management	[3]	$ 1,813,667	$ 1,450,001	250
	33	Base Load Thermal Program	[3]	$ 482,311	$ -	282
	34	Operational Sustainment	[3]	$ 6,264,758	$ 8,788,005	293
Programs Total				$ 8,560,736	$ 10,238,006	
Short-Lived Assets	36	HMI Control Software		$ 2,078,530	$ 132,015	311
Short-Lived Assets Total				$ 2,078,530	$ 132,015	
Grand Total				**$ 58,675,203**	**$ 125,786,006**	

[1] Includes system profroma capital for the period July 1, 2023 through December 31, 2023.
[2] Totals exclude Idaho and Oregon direct business cases from revenue requirement in this case.
[3] Select Generation business cases are being consolidated into three programs based on driver: Operation Sustainment, Asset Lifecycle Management, and Operational Safety and Compliance. See Alexander Testimony.

Cabinet Gorge Station Service

EXECUTIVE SUMMARY

PROJECT NEED: Cabinet Gorge Hydroelectric Development (HED) is the second largest such generating plant in Avista's hydropower fleet. It is located on the Clark Fork River in Bonner County, Idaho. With four generators, it has a 270 MW output capacity. In particular, the Station Service equipment is vital to the plant's continued operation. Station Service equipment includes Load Centers, Transformers, Switchgear, Power Centers and Neutral Grounding Resisters. This equipment is used to operate the generating plant. It includes energy consumed for plant lighting, power, and auxiliary facilities in support of the electricity generation system. Built in 1952, the plant has retained most of its original equipment which is now aging and at end of life.

RECOMMENDED SOLUTION: This request is to upgrade the Station Service Power Centers and associated equipment.

ALTERNATIVES CONSIDERED:

- Alternative 1: Do nothing

COST OF RECOMMENDED SOLUTION: $17.6 M

ADDITIONAL INFO: It is recommended that this aging equipment be replaced to ensure the continued safe operation of the plant. Safe operation of the plant contributes to grid optimization, reliability, and personnel safety. As many other equipment upgrades are underway at Cabinet Gorge, the timing of these Station Service replacements has been coordinated to reduce plant outages. In terms of risk, if this equipment is not upgraded, failure poses substantial hazards not only to the plant's operation but also to plant personnel as failed equipment can cause significant bodily injury and fire danger.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Glen Farmer	Initial draft of original business case	8/1/2020	
2.0	Chris Clemens	Updated for the 2022-2026 SCRUM	7/6/2021	5-year Capitol Planning Process
3.0	Chris Clemens	Updated for the 2023-2027 SCRUM	8/23/2022	5-year Capitol Planning Process
4.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$5,200,000	$ 0
2025	$600,000	$17.6 M
2026	$ 0	$ 0
2027	$ 0	$ 0
2028	$ 0	$ 0

Project Life Span	2017-2025
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

Station Service equipment is vital to the plant's continued operation. Station Service equipment includes Load Centers, Transformers, Switchgear, Power Centers and Neutral Grounding Resisters. This equipment is used to operate the generating plant. The existing equipment is the original equipment. Issues include manufacturers no longer support maintenance activities; can't add anything to Station Service due to capacity limitations; decrease in reliability and safety from the standpoint of protecting equipment and personnel.

1.2 Discuss the major drivers of the business case

Major drivers for this project include improved reliability and safety; manufacturers support for maintenance; address additions to capacity and obtain better insight into each individual feeder or starter.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

As many other equipment upgrades are underway at Cabinet Gorge, the timing of these Station Service replacements has been coordinated to reduce plant outages. In terms of risk, if this equipment is not upgraded, failure poses substantial hazards not only to the plant's operation but also to plant personnel as failed equipment can cause significant bodily injury and fire danger.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. [Avista Strategic Goals]

Upgrading the Station Service equipment at Cabinet Gorge contributes to the safe and responsible design, construction, operation and maintenance of Avista's generating fleet.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

No studies were performed. However, in the 2000's, additional protection was added to the existing main feeders to improve safety. Feeder breakers were rebuilt in 2006. It was identified that the Power Centers and Load Centers were in poor condition and without replacement parts, as equipment failed, we would have to take either the Load Centers or Power Centers offline to attach

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

disconnects to the bus. This would allow us to place equipment back in service but would leave us exposed from a protection standpoint.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: This request is to upgrade the Station Service Power Centers and associated equipment. This aging equipment should be replaced to ensure the continued safe operation of the plant. New equipment will contribute to grid optimization, reliability, and personnel safety.

In Scope: Upgrading capacity and configuration of the Station Service including both Power Centers, Load Centers, Station Service Transformers; Emergency Generator; Emergency Generator building to accommodate a much larger generator**;** replacing all cabling from the load side of 480v station service, adding new 13.8 KV protection breaker in SS1.

Out of Scope: Individual utilization equipment will not be replaced.

Assumptions: New Station Service will connect to existing loads; Station Service components are being designed from 13kV level to the lowest voltage and approaching it as one system rather than individually addressing equipment failures as they arise. The proposed solution is to replace the Transformers and Power Centers first, subsequently these will feed the existing plant Load Centers. Next, the team will install the Load Centers and energize them from the new Power Centers in parallel to the existing plant. This will allow cutover of individual loads without major downtime of the plant.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- When preparing this capital request for Emergency Loads, Power Centers and Load Centers, we worked with Power Engineers to develop an approach and preliminary budget.
- The design is currently at 95%, the vast majority of equipment has been purchased, and construction has started. The proposed budget to finish this project is based on recent crew estimates.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

- The 2018 Hydro Generation Condition & Risk Assessments, is referred to as the "2018 Assessment". Early 2018 GPSS-Hydro department undertook an initiative to revamp their maintenance programs. This included the 2018 Assessment, which was conducted in the hydro plants and incorporated both Risk Assessments and Condition AssessmentsTeams consisting of representatives from the Mechanic, PCM Tech, and Electric Shops, as well as Spokane River Hydro, Clark Fork River Hydro, and Maximo teams were formed and tasked with performing a condition and risk based assessment for assets in all of Avista's hydro facilities. Additional details may be found in the "2018 Hydro Asset Management Program Directory". The full reference is provided below:

  The Condition Assessments were based on the CEATI hydroAMP 2.0 guide. The database developed during the 2018 assessment has been used to create business information tools to identify and analyze equipment strategies to be used by GPSS for making business decisions.

  The purpose of the Risk Assessment was to identify the environmental, financial, and safety risks associated with each asset and what possible consequences might result from an asset failure. Consequences were framed within the Avista Business Risk Matrix. Financial risks might include lost generation during an outage. Probabilities were then estimated as an answer to the following question: Given an asset failure, what is the probability that a particular, potential consequence will actually occur? As an aid to this process, probabilities were selected from a menu of specified probability levels. Results of the Risk Assessments have been used to estimate asset risk costs. Risk cost is the product of the Failure Rate, Potential Consequence of failure. This risk cost is a probable dollar value associated with Avista's exposure risk of each asset.

  The results of the 2018 Assessment have been used to develop Asset Management Plans (AMPs) and a Risk Based Investment Planning (RBIP) tool. AMPs have been developed for a number of the asset classes, such as the generators, turbine runners, GSUs, trash rakes, etc. The AMPs outline capital and maintenance strategies. A primary purpose of the RBIP tool is to bring a risk-based perspective to the capital budget process.

  Reference - Avista Utilities, "2018 Hydro Asset Management Program Directory", Avista Utilities GPSS Dept., March 15, 2019

- Risk Cost calculation from GPSS Asset Management Group: Risk cost is the product of the Failure Rate, Potential Consequence of failure, and the Probability of experiencing the potential consequence in the event of a failure. This risk cost is associated with the probable dollar value associated with Avista's exposure risk of each component. This exposure risk includes the cost of anything that threatens the company, including costs associated with a probable failure of the components (potentially including replacement, refurbishment, or lost generation costs), safety risks associated with normal operation or replacement actions, and probable environmental risks associated with the asset, and at times other costs such as public perception risk mitigation activities. While the company may not be able to shelter itself from risk completely, there are ways it can help protect itself from the effects of business risk, primarily by adopting a risk management strategy as a part of the asset management program. Risk costs not only take account for the exposure risk for an asset but also the criticality (or importance of an asset) and its' current condition. Risk costs are somewhat analogous to insurance premiums. They represent an annual cost, but the year-to-year costs vary with the condition of the assets. If we total the risk costs for all of our assets for the next year, the company would need to have monies set aside for that year to cover the costs associate with the assets that fail that year.\

$$\begin{aligned}&\mathit{Annual\ Risk\ Cost}\\&= [\mathit{Probability\ of\ Failure\ (that\ year)}] \times [\mathit{Consequence}\ \$]\\&\times [\mathit{Likelihood\ of\ actually\ experiencing\ that\ consequence}]\end{aligned}$$

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

Direct offsets are a reduction in maintenance costs for aging equipment, however, no cost estimates have been completed for the savings. Operational safety will be improved by utilizing modern arc-rated equipment.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

The proposed equipment installation will reduce the risk of downtime due to redundant feeds to the power distribution equipment.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: This request is to upgrade the Station Service Power Centers and associated equipment**.**

Alternative 1: Do Nothing; $0

The original equipment is 70 years old. If no action is taken, there is a risk of individual component failure that could force load shedding under certain operational scenarios. Should a catastrophic failure occur with switchgear and/or power cables, it could result in loss of life, and generator unit and/or plant wide forced outages potentially lasting over one year. This is due to the long manufacturing lead time for some types of specialized equipment.

2.7 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Reduced failures of replaced components including Power Centers, Load Centers, Power Cables, Transformers, and PLC Control Centers will increase reliability and demonstrate successful delivery on identified objectives.

2.8 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known

- **Start Date:** Construction started Feb 2023
- **End Date:** Current scheduled Transfer to Plant is Jan 2025

☐Timeline is Unknown

2.9 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/**Governance Team**

The Steering Committee consists of the following members: Jacob Reidt, and Greg Wiggins. Governance Team includes: Chris Clemens and Kristina Newhouse.

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge Station Service business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 12:32 PM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alexis Alexander EA27BABA767E467...	Date:	Aug-15-2023 | 6:51 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		
Signature:	NA	Date:	
Print Name:	NA; Alexis Alexander is currently part of the Project Advisory committee.		
Title:	NA		
Role:	Steering/Advisory Committee Review		

Cabinet Gorge Stoplogs

EXECUTIVE SUMMARY

Cabinet Gorge Spillgates are original to the project (early 1950's vintage). The spillgates are old and in need of replacement. Without a set of reliable stop logs we cannot accomplish the spillgate work that is expected to take place over the next several years. Stop logs are used to isolate spillway gates from the reservoir for the Cabinet Gorge Hydroelectric project. Each stop log assembly comprises nine individual stop log elements or units, which when combined, will allow dewatering of one spillway gate. Each stop log unit is predominantly a welded steel structure designed to fit inside stop log guides embedded inside a large concrete structure, and to minimize water seepage by means of a rubber seal that is compressed under unit self-weight and hydrostatic forces. Without these structures, we cannot efficiently and safely perform the upcoming spillgate work.

Currently Cabinet Gorge spillgates are in need of repair due to missing rivets, bent members, worn-out seals and heavy corrosion. It is worth mentioning that when the condition assessment was performed at Cabinet Gorge, the Spillgates ranked poorly. If those repairs are not made, we pose the risk of a spillgate being out of operational use or a possible gate failure, which could result in an uncontrolled release of water. This would not be in the best interest of public safety, plant safety, and would negatively affect our relationship with FERC, our main governing body and our customers at this facility. The service code for this program is Electric Direct and the jurisdiction for the program is Allocated North serving our electric customers in Washington and Idaho. Operating Cabinet Gorge safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

Cabinet Gorge has operational flexibility and is operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and other types of services necessary to provide a stable electric grid, as well as to maximize value to Avista and its customers. The capacity of this plant alone is 270 MW.The estimated cost of the project is $1.2 Million. It is critical that this project is completed prior to the completion of the planned Cabinet Gorge Spill gate upgrade which is expected to be starting in 2024.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Andrew Burgess	Updated Draft of original business case.	7/6/2020	Budget and year change
2.0	Chris Clemens	Updated for the 2022-2026 SCRUM	7/6/2021	5-year Capitol Planning Process

Cabinet Gorge Stoplogs

GENERAL INFORMATION

Requested Spend Amount	$1,200,000
Requested Spend Time Period	1 years
Requesting Organization/Department	D07/GPSS
Business Case Owner | Sponsor	Chris Clemens | Andy Vickers |
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The Cabinet Gorge spillgates are nearly 70 years old and are in need of repair due to missing rivets, bent members, worn out seals and heavy corrosion. In order to do this needed spillgate work a functional set of Stoplogs must be designed and built prior to spillgate work commencing in 2024. These stoplogs would also help increase the safety factor of the spillway by giving the ability to stop water flow should one of the old spillgates fail or get stuck in the open position. The condition assessment performed in 2018 ranked the spillgates at Cabinet in “poor condition”. A new set of stoplogs are needed to provide stability, reliability and safety of the aging spillway.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The driver for this business case is Asset Condition . The stoplogs we have are no longer functional and require major work to become of use. A new set of stoplogs will support the spillgate work, which will provide stability and longevity in the aging spillway into the future. Cabinet Gorge has operational flexibility and is operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match changing loads, and other types of services necessary to provide a stable electric grid and to maximize value to Avista and its customers.

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

Currently, there is not a functional set of stoplogs at Cabinet. Needless to say we can cannot effectively begin spillgate work in 2024 until a functioning set is constructed. If we stick with the current plan and construct the stoplogs in 2023 we can perform the much needed work to the spillgates and keep the current plan in motion. If this is deffered it will prolong the work to the spillway gates and will put the plant and spillway at risk.

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 stoplogs would be designed in a similar fashion as Noxon's newly built stoplogs. With the improved design they were able to achieve a better fit to the slot, a tighter seal to mitigate leakage through the stoplog and a safer and more effficient way to pick and set the stoplogs into place. Using the design and construction criteria applied at Noxon for their stoplogs will help ensure that we end up with a set of stoplogs that function properly and provide a level of safety for the expected spillgate work and at Cabinet Gorge.

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.

The metric supporting the replacement of the current stoplogs is that they are no longer functional or useful. The original stoplogs in their current state are not feasible or safe to use. Estimated cost to refurbuish the existing set is 700-800k.

Option	Capital Cost	Start	Complete
Replace with new Stoplogs	$1,200,000	01 2023	12 2023
Refurbish existing set (O&M)	$700,000	01 2023	12 2023

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

A field study was performed on the current set of stoplogs by McMILLEN JACOBS in 2017. The study showed that the current set of stoplogs is in "satisfactory" condition. The paint, seals and welds were noted as needing to be addressed. However, these are the original stoplogs and it may be hard to get an engineer to sign off on these as ever being deemed safe to use. The study showed that refurburshement of the existing could be accomplished but the O&M cost estimated to be 700-800k to refurbuish would be more than half the cost of a complete new set. The old set have never been placed in service, so there is some risk involved in refurbuishing. New stoplog design would be similar to the Noxon set that was built in 2018. Major spillgate work in 2024 will require a well designed functional set of stoplogs to complete the work safely.

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 cost of $1,200,000 will be spent in 2023. In first quarter design/engineering will take place. Second quarter material will purchased and fabricratrion will begin. Third quarter fabrication complete. Fourth quarter delivery/commissioning of the stoplogs. If this request moves forward we can offset O&M costs that would be incurred to refurbuish the existing set. There is significant risk involved with not procuring a set of stoplogs prior to the spillgate work scheduled for 2024. The original 1950's vintage spillgates have exceeded there expected life cycle and are in need of 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 timing and execution of this project will enable the needed upgrade of the Cabinet Gorge Spillgate project to proceed in 2024. The spillgates at Cabinet Gorge are original to the project and are at the end of their useful life. With Noxon and Cabinet preparing to officialy enter the EIM in April 2022 it is expected that we will Operate and cycle the spillgates even more once we enter the market. Failure of a spillgate would impose significant operational impacts to the plant , power schedulers, and public by limiting our ability to safey and efficiently control the flow of water through the dam.

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

The repair of the existing set of stoplogs was considered but due to the high cost to refurbuish and the outdated design of the old stop logs, this is not the most reliable and safest option.

The most feasibleand safest option is to design and build a new set of stoplogs for the anticipated spillgate work in 2024.

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.

In first quarter design/engineering will take place. Second quarter material will purchased and fabricratrion will begin. Third quarter fabrication complete. Fourth quarter delivery/commissioning of the stoplogs. Tranfer to plant will occur at the end of the first year once commissioning is complete.

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

Cabinet Gorge affordably supports the power needs of our company and our customers. By taking care of this plant we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Cabinet Gorge is performing at a high level and serving our customers with affordable and reliable energy.

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

Industrial Stoplogs of this size and weight fall into this range of cost. The overall length and width of the stop logs are similar to the set that was built in 2018 for the upcoming Noxon spillgate project. We used the dollar figure spent on Noxon's stoplogs to determine the overall project cost at Cabinet.

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

2.8 Supplemental Information

2.8.1 Identify Customers and Stakeholders that identify with the Business Case.

The primary stakeholders for this project are, the Hydro Regional Manager at Cabinet Gorge, Cabinet Gorge Plant personnel, GPSS Engineering, GPSS Construction and Maintenance, Power Supply, Environmental Resources. Other stakeholders may be identified during project initiation**.**

2.8.2 Identify any related Business Cases

This project will need to be completed prior to the spillgate project expected to start in 2024. The stoplogs will need to be designed built and commissioned prior to any major spillgate work at Cabinet Gorge.

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to this project. The project will be managed within project management practices adopted by the Generation Production and Substation (GPSS) Department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

Cabinet Gorge Stoplogs

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

Management of this project will include the creation of a steering committee which will include mangers representing the key stakeholders involved in this project. Thproject will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is intiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

The undersigned acknowledge they have reviewed the Cabinet Gorge Stoplogs 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:	Chris Clemens	Date:	7/6/2021
Print Name:	Chris Clemens		
Title:	Cabinet Gorge Ops/Maint Manager		
Role:	Business Case Owner		

Signature:		Date:	7/7/2021
Print Name:	Andy Vickers		
Title:	Director GPSS		
Role:	Business Case Sponsor		

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

Template Version: 05/28/2020

Cabinet Gorge Unwatering Pump Upgrade

EXECUTIVE SUMMARY

Cabinet Gorge Hydroelectric Development (HED) is the second largest generating plant in Avista's hydropower fleet. It is located on the Clark Fork River in Bonner County, Idaho. With four generators, it has a 270 MW output capacity. Built in 1952, the plant has retained most of its original equipment which is now aging and at end of life. This plant was designed for base load operation, but today is called on to not only provide load but to quickly change output in response to the variability of wind generation, to changing customer loads and other regulating services needed to balance the system load requirement and assure transmission system reliability.

In order to respond to these new demands, it is necessary to upgrade many of the plant's original systems. One of those critical systems are the unwatering pumps. The unwatering system at Cabinet Gorge consist of two unwatering sumps, each housing three pumps, one 50HP and two 200HP pumps. The 50HP (1,000 GPM) pumps are used to pump out water from normal plant leakage. The 200HP (5,000 GPM) pumps are used to drain out generating units when performing routine maintenance. The pumps, original to the plant, are progressively requiring increasing maintenance. Replacing all six pumps with new pumps at a cost of $800,000 is recommended. Timing for this work is related to Avista's entrance into the Energy Imbalance Market (EIM). The risks for not completing these upgrades include an inability to perform critical maintenance, potentially flooding the plant, and thereby jeopardizing Avista's ability to serve its customers.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Chris Clemens	Initial draft of original business case	10/25/2020	

GENERAL INFORMATION

Requested Spend Amount	$800,000
Requested Spend Time Period	1 year
Requesting Organization/Department	D07/GPSS
Business Case Owner | Sponsor	Chris Clemens | Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The problems being addressed are the plant unwatering pumps at Cabinet Gorge. These pumps have reached the end of their life to provide reliable plant dewatering.

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 current plant unwatering pumps were installed during the original plant construction in the early 1950's. These pumps can no longer be maintained, due to the manufacturer not supporting the equipment. Customers will be benefited through higher reliability of new pumps: i.e. reduced downtime during maintenance evolutions and manufacturer support of the replaced equipment. Also, the original pumps were designed with an oil lubricating system that has the potential to get oil into the river while the pumps are in operation. The new pumps will have a water lubricating system that will meet current environmental requirements.

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

The pumps have reached the end of their service life. They are a critical plant system and without their reliable operation, the plant could easily flood and/or limit the ability to perform unit maintenance. As we go into the EIM market, unit maintenance outages will be scheduled one year in advance and schedule adherence is crucial to plant operation. If these pumps fail, we could jeopardize the maintenance schedule and forgo much needed preventative maintenance activities. In addition, in the case of a failure, the replacement parts or new pumps would have to be manufactured, increasing the length of the downtime. The current systems are not environmentally-friendly so there is a risk in continually polluting our rivers with these outdated oil lubricated pumps.

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.

By replacing the current pumps with new pumps, we will provide consistency with industry standards. These upgrades will improve the plant’s overall reliability. This will also reduce current maintenance costs and provide many years of efficient, reliable and environmentally-sound plant dewatering operations.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

No studies have been performed.

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

Option	Capital Cost	Start	Complete
Replace all six pumps and check valves over a one-year period.	$800,000	01 2022	12 2022
Replacing only the four large pumps and check valves over a one-year period.	$600,000	01 2022	12 2022

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

Capital planning consists of bids from manufacturers to determine the best cost and schedule. Engineering and vendors have been consulted to determine industry best practices and to determine installation costs and 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.

Installations and commissioning of purchased equipment will take place in 2022. Maintenance costs will be reduced because the current pumps require ongoing maintenance. In 2019, Unwatering pump #1 was removed from service because of high vibration and the motor was pulling 60 amps over the nameplate rating. The mechanical crew spent 2 weeks removing the motor and sending it in to be cleaned, baked and dipped. Then the bearings were replaced, and the motor was reinstalled. Neither problem (vibration nor high amperage) was resolved. The cost to perform this maintenance was $50,000. Due to the age of these original pumps, it is difficult to get parts. Similarly, it is not sustainable to fix the vibration issues because the pumps and motors have been modified through the years to keep them in service. It is believed that replacing the pumps will be more cost effective than trying to maintain the current pumps. Reliability will be improved because the new pumps will be maintenance-free for many years.

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 successful upgrade of the system will allow the plant to operate more reliably during the future.

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

There is an alternative in only replacing four of the six pumps. The smaller pumps have had the motors replaced 20 years ago, but the pump itself was not overhauled. The larger pumps, if replaced, could act as a backup if the smaller pump was to fail. Though the smaller pumps would still be utilizing the oil lubricating system. They still should be replaced in the future to meet environmental standards.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

This project would take place over a one-year period. We will procure and install all six pumps within that timeframe. The work would take 1 week per pump, totaling six weeks. We would purchase six pumps in January 2022 and start the installation in June of 2022.

There would be no outages or generation lost during these upgrades. We will be able to replace one pump at a time, keeping the plant unwatering sumps in service.

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

Upgrading the plant unwatering pumps at Cabinet Gorge contributes to the safe and responsible design, construction, operation and maintenance of Avista's generating fleet.

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

We ranked this project based on a ranking matrix to ensure prudent consideration of cost, scheduling and personnel resources. These six pumps are ranked in poor condition. There are only a few assets within the Hydro Department with a poor rating. This shows the need and urgency to replace these pumps.

Cabinet Gorge HED Asset Group	Condition Rating	Unwatering Pumps #1,2,4 &	Unwatering Pumps #3	Unwatering Pumps #6	Unwatering Pumps #7	Pump #8 Backup (for #7)
Unwatering Pumps	Marginal	-0.8	2.8	2.8	9.3	4.2
		Poor	Poor	Poor	Good	Marginal

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The Mechanical shop, Electric shop, Engineering, Operations, Environmental, and Project Management are required.

2.8.2 Identify any related Business Cases

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Steering Committee consists of the following members: Plant Manager, Chief Operator, Station Mechanic and Station Electrician.

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

Persons providing oversight include: Generation Mechanical Engineer, Mechanical Shop Forman and Station Mechanic.

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

The persons identified in Section 3.2 will be called on to evaluate recommendations raised from the Stakeholder Group. Documented decisions will be stored in the project folder located on the department network drive.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge Unwatering Pump Upgrade 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: Chris Clemens Date: 7/6/2021
Print Name: Chris Clemens
Title: Cabinet Gorge Ops/Maint Manager
Role: Business Case Owner

Signature: Andy Vickers Date: 7/7/2021
Print Name: Andy Vickers
Title: Director GPSS
Role: Business Case Sponsor

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

Generation DC Supplied System Update

EXECUTIVE SUMMARY

The Generation DC Supplied System program covers all the generation and control facilities. It is the backbone for supplying power to the protective relays, breakers, controls and communication systems. With NERC requirements followed and design enhancements the DC system is being monitored, tested and remains reliable. Experience shows that we must continually monitor, review and maintain our DC system. The equipment manufactures gives an estimated life span to the batteries and auxiliary equipment. Some of these estimates have not hit the mark and have been changed out early due to failing tests or issues with the equipment. Proven manufactures are used to improve reliability and life. The risk of not approving this program would reduce the reliability of our generation and control facilities.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Glen Farmer	Initial version	4/10/2017	
2.0	Glen Farmer	Updated timeline from 5-year plan.	8/1/2020	

GENERAL INFORMATION

Year	Current Approval	Requested Change	Proposed Total
2021	$840,000	$0	$840,000
2022	$900,000	$0	$900,000
2023	$840,000	$0	$840,000
2024	$900,000	$0	$900,000
2025	$0	$800,000	$800,000

Requested Spend Time Period	yearly
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Glen Farmer | Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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

Traditionally, the Direct Current (DC) system, (aka Battery System) at each generation plant is used for protection and monitoring of the plant. All the protection relays, breaker control circuits and monitoring circuits are fed from this source. The source is assumed to always be on-line and able to supply the critical load for a predetermined length of time.

As technology has evolved, other standalone DC systems that were installed at different times. Typical plants now have standalone DC Systems for: general station, Uninterruptible Power Supplies (UPS), governors (electronic turbine speed controllers), communications and control systems. Each of these systems have a battery bank, battery charger, converters to supply different voltages, and distribution panels and circuits. As things have changed on the generating units or in the balance of plant systems, the DC load requirement has significantly increased and the time duration for the systems to supply this critical load has increased. Our current practice is to replace the battery banks per manufactures life cycle recommendations. This practice is not addressing the additional load added to the systems.

Some of the other issues we have had on the DC systems are the failing of battery cells due to inconsistent temperature and environmental control needed to maintain these present battery systems. The system life cycle is 20 years at its normal operating temperature of 77 degrees F. For temperatures fifteen degrees F over the normal operating temperature the life cycle is decreased by 50 percent. Component failure, utilization from multiple extended outages and manufactures quality are other problems we have experienced on these systems.

Finally, there are compliance requirements from the North American Electric Reliability Corporation (NERC) for inspections, maintenance and testing of the battery banks to make sure they are in good working order and will perform when called upon. In order to perform these inspections and maintenance, and testing needs, it requires either unit or plant outages to comply with the requirements for multiple DC systems that are now present in our stations.

To address these multiple issues, a new Generation Plant DC Standard was developed by the engineering group. The new Generation Plant DC Standard System provides for layers of back up and redundancy to address current and future capacity needs as well as addressing maintenance and testing requirements. This Program will replace existing DC systems at Avista's owned and operated generation plants with a system that meets this new design standard. The Generation Plant DC Standard will be used as a guide for defining the base scope of the 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 activity objectives are to order the plant replacements in a timeline that will allow for stages of a project to happen and use our engineering and construction staffing. At each plant the DC System will be updated to meet the current Generation Plant DC System Standard and the following:

1. Comply with NERC requirements for inspection and testing.
2. Address battery room environmental conditions to optimize battery life.
3. Replace any legacy UPS systems with an invertor system.
4. Address auxiliary equipment based on life cycle.
5. Hydrogen sensing and fire alarm, eyewash station and lighting.
6. Wall separation of batteries and auxiliary equipment.
7. Install Programmable logic controller monitoring and new operating screens to provide visibility for operations and maintenance purposes.
8. Provide new distribution panels, disconnect switches, voltage conversion devices for communications equipment that operate at different voltages.
9. Establish current drawings, construction documents, I/O list, plans, schedules, manuals and as-builts.

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

The biggest risk is a battery bank not being able to provide load to the plant. The batteries are supposed to have a 20-year life based on the manufacture, but we have only seen one manufacture perform to this level. We are using this manufacture going forward and expect to have them last the full life.

If not approved and we have a failure of a battery then budgets, schedules and resources on other projects would be diverted to handle fixing the 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.

With the DC design standard, we are creating the best possible environment for the battery banks and have enhanced monitoring of the system. This gives Operations better insight to how the DC system is functioning.

1.5 Supplemental Information

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

The preparation of our DC Standard incorporates IEEE design parameters and standards. It has redundancy built in for testing and suppling load.

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
1. Address the DC systems as they fail testing or battery issues arise.	$1,315,000/yr	01/2017	12/2030
2. Establish an independent DC system replacement program to bring plants to a standard as quickly as possible.	$1,315,000/yr	05/2027	8/2026

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

The capital request was developed from budgetary quotes from manufacture and compared to previous projects of similar type.

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.**

There are normally three different projects happing each year. One project would be in the initiation phase, the next would be in the execution phase and the next would be in the close out phase. Maintenance is reduced after the execution phase and we have not seen it pick back up for the first five years of the life span.

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 engineer business process would be used. This allows for the stakeholders to be involved from the beginning to the end of the project.

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

The risk of addressing the DC system when there is an issue is usually that is too late. We have had one instance where the DC system failed and some equipment was damaged due to this not functioning correctly.

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.

We normally have one project per year become used and useful.

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

A new DC System contributes to the Safe and responsible design, construction, operation and maintenance of Avista's generation fleet.

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

We ranked this project based on a ranking matrix to ensure prudent consideration of costs, scheduling and personnel resources.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Electric shop, Relay shop, Engineering, Operations, Protection, Environmental, Project Management and Power Supply.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

The Steering Committee consists of the following members: Manager of Project Delivery, Manager of Maintenance and Construction, Manager of Hydro Operations & Maintenance.

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

Persons providing oversight include: Generation Electrical Engineering Manager, Forman PCM shop, Manager C&M - Electric Shop and the Plant Managers.

The undersigned acknowledge they have reviewed the Generation DC Supplied System Update 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:	Glen S. Farmer	Date:	8/1/2020
Print Name:	Glen Farmer		
Title:	Generation Electrical Engineering Manager		
Role:	Business Case Owner		

Signature:	ANdrew Vickers	Date:	8/3/2020
Print Name:	Andy Vickers		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Bob Weisbeck		

Generation DC Supplied System Update

Title:	Manager, Hydro Operations and Maintenance
Role:	Steering/Advisory Committee Review

Template Version: 05/28/2020

Generation Masonry Building Rehabilitation

EXECUTIVE SUMMARY

Several Buildings located at Avista's generating facilities are constructed with masonry and were constructed over 100 years ago. These buildings include: The Little Falls Powerhouse, the Little Falls Gate Building, the Long Lake Powerhouse, the Nine Mile Powerhouse, the Post Street Station, The Post Falls Powerhouse, the Post Falls Substation Building and the Ross Park Building (eight buildings in six locations). The grout and brick in many cases has begun to fail which is creating a serious personnel and public hazard as bricks become loose in the walls and parapets and fall to the ground. This has become critical, especially during the freeze and thaw cycles in the spring. The condition of some of the masonry structures, especially those near the top of the walls and parts of the roof structure have exceeded their useful life and pose a threat to the structural integrity of the buildings.

The operational availability for these generating facilities is paramount. The service code for this program is Electric Direct and the jurisdiction for this project is Allocated North serving our electric customers in Washington and Idaho. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

The solution to this problem is to assess each building and dismantle and rebuild the damaged sections of the walls and support structures with methods and materials that will restore the structural integrity of the building. This project is expected to cost $6,000,000 over a period of six years in order to address the issues with all eight buildings in the six locations.

The business driver for this project is Asset Condition. Without action, the driver may become Failed Plant. Without this project, O&M costs will be spent to spot repair the buildings as required. This has been the strategy in the past. As the buildings continue to age, these costs will rise. In addition, the spot repairs will not prevent more bricks from becoming loose every year. This poses an unacceptable risk of injury and possible death if the bricks fall on personnel at the plant or in the case of the Post Street Station in downtown Spokane, members of the public. If the problem is not remedied in a timely manner, the structural integrity of the buildings will be compromised which could result in the collapse of sections of the buildings which would endanger personnel and adversely affect operations.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Bob Weisbeck	Initial draft of original business case	7/1/2020	
1.0	Bob Weisbeck	Final version approved	7/6/2020	
2.0	Bob Weisbeck	Updated for 2022 to 2026 Capital Plan	6/22/2021	

Generation Masonry Building Rehabilitation

GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requested Spend Time Period	7 years
Requesting Organization/Department	A07/GPSS
Business Case Owner | Sponsor	Bob Weisbeck | Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

Several Buildings located at Avista's generating facilities are constructed with masonry and were constructed over 100 years ago. These buildings include: The Little Falls Powerhouse, the Little Falls Gate Building, the Long Lake Powerhouse, the Nine Mile Powerhouse, the Post Street Station, The Post Falls Powerhouse, the Post Falls Substation Building and the Ross Park Building. The grout and brick in many cases has begun to fail which is creating a serious personnel and public hazard as bricks become loose in the walls and parapets and fall to the ground. This has become critical, especially during the freeze and thaw cycles in the spring. The condition of some of the masonry structures, especially those near the top of the walls and parts of the roof structure have exceeded their useful life and pose a threat to the structural integrity of the buildings.

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 business driver for this project is Asset Condition. Without action, the driver may become Failed Plant. Without this project, O&M costs will be spent to spot repair the buildings as required. This has been the strategy in the past.

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

As the buildings continue to age, these costs will rise. In addition, the spot repairs will not prevent more bricks from becoming loose every year. This poses an unacceptable risk of injury and possible death if the bricks fall on personnel at the plant or in the case of the Post Street Station in downtown Spokane, members of the public. If the problem is not remedied in a timely manner, the structural integrity of the buildings will be compromised which could result in the collapse of sections of the buildings which would endanger personnel and adversely affect 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.

Over the past two years, O&M costs have been incurred to spot repair critical conditions in some of the buildings. This has proven to be only a temporary fix. The measure of success in this project would be the complete rebuild of the damaged structures so that the failing walls and structure would be remedied and falling debris would be eliminated.

1.5 Supplemental Information

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

Over the past two years, repairs were made to the Long Lake Powerhouse and the Post Street Station. In 2019 approximately $122,000 was spent to repair Long Lake. In 2020, $297,000 was spent to repair Post Street Station. These expenditures were considered O&M and only partially repaired the issue. This project would reduce or eliminate these costs since the project would dismantle and rebuild sections to restore the structural integrity of the buildings and greatly reduce the likelihood of falling debris.

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 grout and brick in many cases has begun to fail which is creating a serious personnel and public hazard as bricks become loose in the walls and parapets and fall to the ground. This has become critical, especially during the freeze and thaw cycles in the spring. The condition of some of the masonry structures, especially those near the top of the walls and parts of the roof structure have exceeded their useful life and pose a threat to the structural integrity of the building

2.

Option	Capital Cost	Start	Complete
Rehabilitate Existing Masonry Structures	$3,000,000	01 2022	12 2027
Continue to repair current system (O&M)	$0	01 2021	12 2025

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

The O&M costs of repairing the buildings was considered in this project. Also, the experience of the spot repairs has shown that these repairs will not prevent more bricks from becoming loose every year. This poses an unacceptable risk of injury and possible death if the bricks fall on personnel at the plant or in the case of the Post Street Station in downtown Spokane, members of the public. Experience has also shown If the problem is not remedied in a timely manner, the structural integrity of the buildings will be compromised which could result in the collapse of sections of the buildings which would endanger personnel and adversely affect operations.

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.**

Over the past two years, repairs were made to the Long Lake Powerhouse and the Post Street Station. In 2019 approximately $122,000 was spent to repair Long Lake. In 2020, $297,000 was spent to repair Post Street Station. These expenditures were considered O&M and only partially repaired the issue. This project would reduce or eliminate these costs since the project would dismantle and rebuild sections to restore the structural integrity of the buildings and greatly reduce the likelihood of falling debris. Rehabilitation of these structures is considered capital and the annual expenditure is forecast to be $500,000 per year for six years

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 number and duration of outages in the hydro generating facilities should be minimal due to this work. Much of the work will be done on the external sections of the building. However, when work is being performed above or adjacent to operating units, outages may be required to install scaffolding and other protective equipment.

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

The alternative that has been considered and tried is the spot repairs to sections of the buildings when the deterioration has caused bricks to fall and structures to begin to fail. These repairs did not prevent more bricks from becoming loose every year. This has posed a risk as the bricks fall several stories from the walls and roof structure. Repairs have been performed at Long Lake and Post Street station and have not remedied the problem. Experience has also shown If the problem is not remedied in a timely manner, the structural integrity of the buildings will be compromised which could result in the collapse of sections of the buildings which would endanger personnel and adversely affect operations.

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 project is expected to take six years in order to remedy the masonry condition in eight facilities. The strategy is to work on one location per year until all the issues have been addressed. These buildings include: The Little Falls Powerhouse, the Little Falls Gate Building, the Long Lake Powerhouse, the Nine Mile Powerhouse, the Post Street Station, The Post Falls Powerhouse, the Post Falls Substation Building and the Ross Park Building.

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

The structural integrity of these buildings is essential in supporting the function of the generating facilities on the Spokane River. These plants affordably support the power needs of our company and our customers. By taking care of these facilities we support our mission of improving our customer’s lives through innovative energy solutions which includes hydroelectric generation. By rehabilitating these buildings, we ensure that hydro facilities are performing at a high level and serving our customers with affordable and reliable energy.

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 cost of repairing the Post Street Station amounted to approximately $297,000. This addressed immediate issues on one wall and part of the roof structure. The size and configuration of the masonry buildings considered in this project are similar. In order to remedy the structural issues of each plant, it is expected to be three times this amount. The projected estimate is $1,000,000 per locations. The work is being spread out over seven years to enable the use of one contractor and control costs.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are, the Hydro Regional Managers for the Upper Spokane plants and Long Lake/Little Falls, Plant personnel, Facilities, Power Supply, Environmental Resources and the City of Spokane. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

This Business Case should be independent of other projects.

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

Generation Masonry Building Rehabilitation

The undersigned acknowledge they have reviewed the Cabinet Gorge HVAC 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: R. S. Weisbeck   Date: 6/24/21
Print Name: R. S. Weisbeck
Title: Manager, Hydro Ops and Maintenance
Role: Business Case Owner

Signature: ANdrew Vickers   Date: 7/6/2021
Print Name: Andrew Vickers
Title: Director GPSS
Role: Business Case Sponsor

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

Template Version: 05/28/2020

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name: Generation Masonry Building Rehabilitation

2. Business Case Owner: Bob Weisbeck, Sr Manager Hydro Operations and Maintenance

3. Director Responsible: Andy Vickers, Director of Generation Production and Substation Support

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

Response - The projects included in this business case include several buildings located at Avista's generating facilities that are over 100 years old and are considered at or near the end of their useful life. This includes eight buildings in six locations.

The projects in this business case benefit customers because sound structures and the remedy of crumbling masonry is necessary to maintain safety, reliability, and availability of the hydroelectric generating facilities. The grout and brick in many cases has begun to fail which is creating a serious personnel and public hazard when pieces of the masonry fall from significant heights. In many cases the structural integrity of the wall and parapets have been compromised which presents hazards to equipment and operations.

These projects don't carry any direct savings as they are focused on restoring the structural integrity of the buildings and not on incremental improvements in reduced maintenance or reduction of labor. While these projects are not intended to directly lead to savings, they are critical to the maintaining the ongoing personnel and public safety and unit reliability and plant availability.

Quantified direct savings:

2022	2023	Lifetime
0	0	

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Response - The projects included in this business case include several buildings located at Avista's generating facilities that are over 100 years old and are considered at or near the end of their useful life. This includes eight buildings in six locations.

There will be indirect costs of performing the projects in this business case by offsetting emergency repairs of the building which have taken place, due to the freeze/thaw cycle in the spring and fall and the continued deterioration of the grout and masonry. Historically this has been considered emergency maintenance since the repairs focused on the immediate areas of concern and did not address the entire wall or structure. These emergency repairs were not included in the Operations and Maintenance Budget.

There is also a safety benefit that will be realized by completing the work in this business case. Reduction in the probability of falling brick and masonry components is an import aspect of this work.

The amount of money spent on masonry repairs is included below. The calculations for quantified indirect savings included an average annual cost based on this historical spend.

Cost of masonry repairs:

2019 – Long lake $122,000

2020 – Post Street Station $297,000

Total cost $419,000

Average annual cost $209,500

Quantified indirect savings:

2022	2023	Lifetime
209,500	209,500	1,257,000 *

*based on the lifetime of six years for this project.

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

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

Director Name Andy Vickers

Director Signature ANdrew Vickers

Date 10/22/2021

KF_4160V Station Service_Replacement

EXECUTIVE SUMMARY

All generation facilities require Station Service to provide electric power to the plant. Station Service components include Motor Control Centers, Load Centers, Emergency Load Centers, various breakers, transformers and conductors. Station Service is an elaborate system with multiple built-in redundancies, multiple voltages designed to protect the plant's electrical system

The plant low voltage 4160 V switch gear has been identified by AIG insurance inspection as being out of compliance. With aging equipment the plant is experiencing challenges with service and parts to maintains the breakers. The plant is currently installing new fuel yard equipment which will require new and upsized power needs in the fuel yard. The plant fuel yard project team has put in place a temporary work around to power the new yard but this solution is not permenant.

The recommendation is to replace the 4160 V station service. This replacement will correct the insurance defficency and increase reliability to the plant critical loads. A high-level cost estimate was received from Columbia Electric and compared to Avista actual project costs of the from other GPSS locations.

If this project is not funded the plant will have more frequent forced outages due to electrical equipment failures.

This project will impact customers in service code Electric Direct jurisdiction Allocated North serving our electric customers in Washington and Idaho.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Greg Wiggins*	*Initial draft of original business case*	*7/8/2021*	
Rev. 2	*Greg Wiggins*	*Revised schedule, costs and offsets*	*8/20/2022*	

GENERAL INFORMATION

Requested Spend Amount	$2,135,000
Requested Spend Time Period	3
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Greg Wiggins | Alex Alexander
Sponsor Organization/Department	GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

In recent years, upgrades and maintenance of the Kettle Falls Station Service have been performed including 480 V breaker remanufacture, 480 V transformer replacements, and MCC replacements. The aging 4160 V breakers were sent to be refurbished through the 2013-2015 timeframe. However, during the refurbishing processes not all of the old parts were replaced and parts were misaligned during reassembly. As a consequence, the plant continues to replace failing parts. Replacement parts themselves are not readily available and custom fabricated parts have had a tendency to fail and are expensive. In order to meet maintenance needs, the plant purchases used breakers to strip for parts. The pictures below show some examples of damaged parts.

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 for this project are Asset Condtition and Mandatory & Compliance.

The 4160 V gear feeds motors critical to plant operations. Due to the nature of the supplied loads being motors, the equipment is subject to higher operation counts than normal breakers, with two breakers having exceeded 1,700 operations. The frequent operations add to wear and increase the risk of failure.

The insurance company for the plant has brought up issues regarding the 4160 V switchgear arrangement as it regards to feeding the Boiler Feed Pumps. According to Paragraph PG-61.1 of the ASME Boiler and Pressure Vessel Codes Section I, one such means of feeding the boiler shall not be susceptible to the same interruption as the other. The concern revolves around the idea that if one of the Boiler Feed Pumps is interrupted, the second would need to be able to run and prevent damage to the boiler. Originally, only one Boiler Feed Pump was electrically driven with the second driven by steam turbine. At some point the steam turbine drive was replaced with an electric motor. To satisfy the insurance requirements, changes to the 4160 V bus will need to be made in order to be able to feed the pumps from separate busses. A potential alternative solution would be to revert the modified boiler feed pump back to being driven by steam turbine. This solution is being evaluated by the Manager of Thermal Operations and Maintenance, and is not considered further in this plan.

Another significant change at the Kettle Falls plant is the addition of the new Fuel Handling System/Fuel Yard Processing Building. The planned design has the power feed for the new system sourced from the local distribution feeder. This subjects fuel handling operations to disturbances on the distribution system. To improve the reliability of operations, a feed from the main station service 4160 V bus to the new fuel yard bus is desired. As the Fuel Yard project moved into the execution stage there was a cost saving measure to not go with the new service and to add the feed from the 4160 bus. This is fine but it still only allows for one source to the Fuel Yard.

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

The equipment that is energized from 4160 V gear is critical equipment to plant operations such as the ID fan, FD fan, boiler feed water pumps, circulating water pumps and the fuel yard hammer hog. The plant can not run without the ID and FD fans and there are not redundant fans so the energy source is just as critical as the fans themselves. The plant is having trouble sourcing replacement parts and have recently began purchasing used equipment in decent shape to use as spare parts.

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.

Installing the new gear with a tie breaker and supplying the power from two separate sources will satisfy the insurance defficency. The new fuel yard equipment will need to have this new power supply to be a complete project. They fuel yard is scheduled to be commissioned in 2022 or 2023.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

2015 AIG Insurance All Risk Survey Report

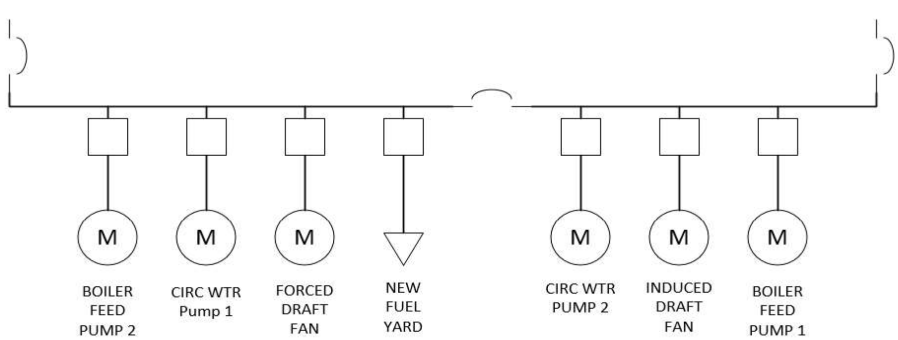
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Breaker Position	2A1	2A2	2A3	2A4	2A5	2A6	2A7	2A8	2A9
Operation Count	629	887	630	1829	287	204	736	16	1744

Average of 774 operations. Plant technicians did mention that some of the operation counters were broken for an unknown period of time and later fixed, so the counts shown are lower than the actuals

2. PROPOSAL AND RECOMMENDED SOLUTION

The recommended solution is to replace the existing switchgear with a new Main-Tie-Main configuration. Replacing the switchgear directly addresses the concerns regarding the state of wear of the existing breakers. The new gear would also have a breaker that can be used as a feed to the new fuel yard. This configuration would also directly address the insurance company's concerns about being able to feed the two boiler feed pumps from separate busses. All concerns are addressed with this alternative. An example of the arrangement is shown below.



Option	Capital Cost	Start	Complete
Replace the 4160 V Station Service with Tie	$*2,135,000*	05/2023	06/2025
Replace the 4160 V Station Service	$2,013,000	05/2023	06/2025

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

The plant will need to continue purchasing old breakers to salvage for parts or have custom parts manufactured, maintaining a non-inconsequential O&M burden. This alternative also does not address the insurance company's concern regarding the Boiler Feed Pumps or provide a reliable power source to the new fuel yard.

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.

Engineering will begin in 2023 followed by procurement in 2024 with the installation being done during the 2025 annual Spring outage.

Table 1 - Project Cash Flows

Year	Recommended Alternative Cash Flow
2023	$95,000
2024	$1,540,000
2025	$500,000

A forced outage caused by a failure on the 4160v bus could extend many months. The estimated daily Power Supply outage cost for this facility is $69,700 (refer to 20220825 Thermal Daily Outage Cost Estimation Tool CONFIDENTIAL.xlsx). Using an estimated 1 month for an emergency replacement, total Power Supply outage costs due to a failure is estimated to be: $2,091,000

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

This work will be done during the 2025 annual Spring outage. There will be a short impact and outage to fuel deliveries that will be managed through weekend work

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

The alternatives discussed around additional costs to mitigate the insurance deficiency and the added costs were evaluated from Risk Management and a decision was made to install the tie breaker.

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.

Year	2023					2024												2025											
Month	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Intiation																													
Planning																													
Execution																													
Closing																													

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

This project aligns with supporting a safe and reliable operating unit.

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

An evaluation was completed by GPSS Electrical engineering and Risk Management. Both groups supported the project as plant reliability and insurance deficiency will be resolved with the project.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

KF Plant Management

KF Plant Techs

GPSS Electrical Shop Crews

GPSS Electrical Engineering

Risk Management

2.8.2 Identify any related Business Cases

Kettle Falls Fuel Yard Replacement Project

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

GPSS Asset Management

KF Plant Management

GPSS Thermal Operations and Maintenance Manager

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

Quartly status meeting up to construction then weekly meetings.

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

Plant management will report changes requests to the GPSS Thermal Operations and Maintenance manager. Decissions will be made following the GPSS project management process and Corporate Contract Change Order protocol.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the KF 4160 V Station Service Replacement project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Greg Wiggins	Date:	8/20/2022
Print Name:	Greg Wiggins		
Title:	Plant Manager		
Role:	Business Case Owner		

Signature:	Alexis Alexander Digitally signed by Alexis Alexander Date: 2022.09.02 11:31:04 -07'00'	Date:	
Print Name:	Alexis Alexander		
Title:	Director GPSS		
Role:	Business Case Sponsor		

Signature:	Thomas C Dempsey Digitally signed by Thomas C Dempsey Date: 2022.08.31 11:38:56 -07'00'	Date:	08/31/2022
Print Name:	Thomas Dempsey		
Title:	Thermal Operations and Maint Mgr		
Role:	Steering/Advisory Committee Review		

GPSS_KF_Secondary Superheater_Replacement

EXECUTIVE SUMMARY

The Kettle Falls Generating Station processes nearly 450,000 tons of waste wood annually. During the combustion process the heat generated is transferred to the boiler internal water and steam systems. Water is heated until it becomes steam. The steam is conditioned in the drum before entering two sections of superheater steam pendants. The first section is the primary superheater which takes high pressure saturated steam from the steam drum and converts it into dry superheated steam. The secondary superheater conditions the steam to maintain final steaming conditions at 950 F at 1,550 psi to be used in the steam turbine. The turbine converts the steam into 53 MW's of green renewable energy.

After a 1997 inspection revealed excessive corrosion caused severe tube wall thinning, both sections of the superheater were replaced in 1998. The replacement superheater tube material was upgraded from original design with engineering studies showing potential of a 20-year life expectancy from the upgrade. Recent testing from Industrial Inspection and Analysis revealed the secondary superheater has undergone localized wall thinning from erosion. The analysis indicates the superheater tubes have experienced significant non-uniform scaling and tube wall loss on the exterior surfaces up to 54% of the wall thickness.

The recommendation is to replace the secondary superheater. This replacement will restore plant reliability for Avista's customers. A high-level cost estimate was received from boiler maker CH Murphy and compared to Avista actual project costs of the economizer tube replacement project in 2019.

If this project is not funded the plant will continue to have more frequent forced outages due to secondary superheater tube leaks.

This project will impact customers in service code Electric Direct jurisdiction Allocated North serving our electric customers in Washington and Idaho.

VERSION HISTORY

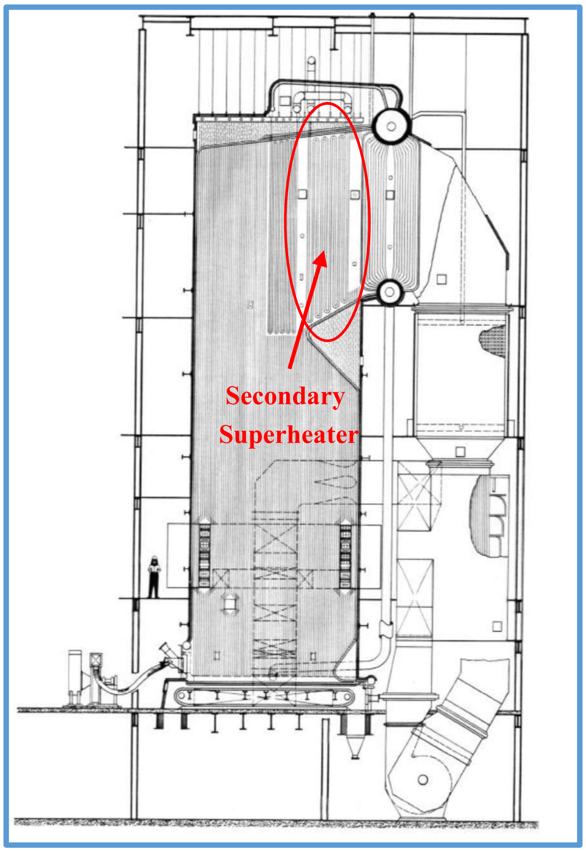
Version	Author	Description	Date	Notes
Draft	*Greg Wiggins*	*KF_Secondary Superheater_Replace*	*6/22/2021*	
Rev. 1	*Greg Wiggins*	*Revised schedule, costs, and offsets*	*8/20/2022*	*Revised schedule and cost*

GENERAL INFORMATION

Requested Spend Amount	$2,800,000
Requested Spend Time Period	2 years
Requesting Organization/Department	K07 / GPSS
Business Case Owner | Sponsor	Greg Wiggins | Alexis Alexander
Sponsor Organization/Department	K07 / GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

The Kettle Falls Generating Station thermal plant is a wood fired natural circulation boiler. The wood is burned on a traveling grate system and the heat from the fire is transferred into the boiler water walls, superheater, generation section, economizer and air heater. The process begins with pumping water through a series of heat exchangers to add energy to the boiler water.



The boiler water is heated to steam at 415,000 lbs/hr of steam flow. The saturated wet steam passes through two sections of superheater tube bundles. The first section is the primary superheater followed by the secondary superheater. Steam exits the secondary superheater at 950 F superheated steam at 1,550 psi operating pressure to drive the steam turbine generator. The steam is then condensed back into water and is pumped back through the heating system again.

During the combustion process fly ash is carried in the flue gas stream up the furnace and through the superheater, generation bank and economizer. The fly ash is corrosive and abrasive by nature. Over the past 23 years the fly ash has caused random thinning to the outside of secondary superheater tube walls.

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

The secondary superheater is reaching the minimum tube wall thickness for safe and reliable operations of the plant. The thin areas cause tube failure as the high-pressure steam inside the tube bursts the thin tube wall. The plant must be taken offline to make the repairs. Depending on the severity of the leak the unit might

need to be taken offline immediately but can sometimes run for a few weeks until the best economic opportunity allows for the shutdown to be scheduled. If the unit is left running with a superheater tube leak the steam blowing from the tube may hit an adjacent tube steam cut through the metal and create another tube leak. The random thinning and scale make it impossible to predict when and where the next tube leak will occur.

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 for this project is Asset Condition. The superheater is a critical component of the boiler circuit. Without the superheater the plant is unable to generate electricity. Restoring the superheater will increase plant reliability.

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

The plant will continue to experience forced outages due to superheater tube leaks. Repairs, outage duration and costs vary depending on location of the leak and the number of tubes that have been impacted. Repair costs vary from $30k to $125k with outages lasting between 48 hours to a full week.

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.

Plant reliability will increase as the unit has been averaging a couple tubes leaks a year since 2012. Non-destructive testing will be able to monitor tube integrity with new baseline data which will help predict the when the next replacement should take place. Previous study from JP Industrial in 1997 expected a 20-year operating cycle on the previous superheater replacement which was reached in 2018.

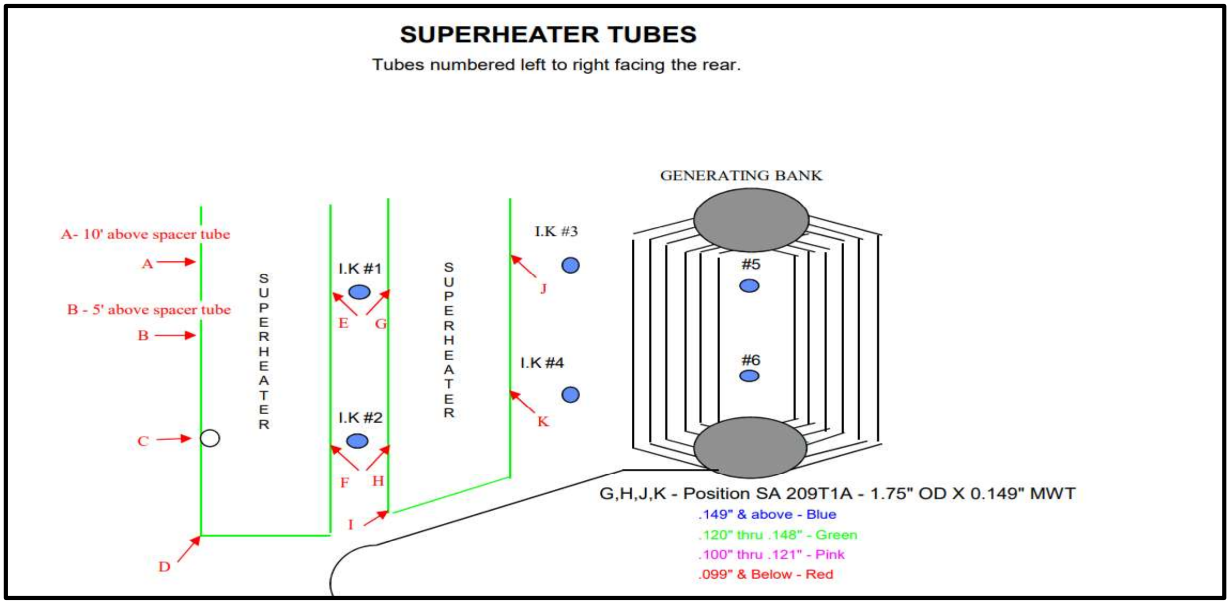
1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

JP Industrial – Superheater engineering study – Kettle Falls Plant Library *This engineering study was completed in 1997. It included tube analysis completed by an independent firm McDermott Technology. The study focused on the superheater tube failures and root causes. The JP Industrial report suggested a replacement superheater could expect to have a 20-year operating lifespan under similar operating conditions.*

5 Star Non-Destructive Testing Reports – Kettle Falls Outage Files *Annual Outage NDT inspection reports beginning in 1990 continuing every other year to current year. These inspection record tube thickness of key areas of the boiler.*

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 boiler graph above is used during the annual outage to measure key areas of the boiler. Areas include the water walls, chill tubes, primary and secondary superheaters, generation bank and economizer tube. A contractor uses non-destructive testing equipment to accurately measure the thickness of the tube walls and compare to a new tube. Show in the chart is the color-coded measurements showing different levels of concern. Colors blue and green are considered in good condition. Pink color is concern while Red is must repair. Focus areas of the secondary superheater are found in the G, H, I, and J. Each tube is measured roughly in the same spot every two years. Pink areas are indicating issues while Red indications require repairs to maintain the boiler operating license from the State.

5 Star Testing is a contractor that has been recording the tube data for the plant

for over 20 years to maintain accurate and consistent inspection practices and test results. During plant outages, scaffolding is installed to gain access to key areas of the boiler so these reading can be recorded. Sometimes scaffolding is not built due to outage duration, so those areas are recorded as NO ACCESS. Below is the data take over a six-year interval. In 2014 there were no areas of concern recorded in the secondary superheater section. In 2016 scaffolding was not installed to gain access to area I. The 2016 outage revealed several tubes reaching a measurement of concern. Tube shields were installed to prolong the life of the tubes recorded in pink. Those tubes are no longer measured, and some thermal conductivity efficiency is reduced to extend the life of the tube. In 2018 section in I were also recorded as a warning area.

2014

I	J	K
0.232	0.164	0.167
0.220	0.150	0.137
0.214	0.162	0.162
0.216	0.174	0.168
0.197	0.132	0.144
0.212	0.157	0.165
0.197	0.161	0.128
0.193	0.164	0.162
0.196	0.168	0.170
0.209	0.165	0.142
0.220	0.162	0.151
0.211	0.170	0.166
0.193	0.174	0.166
0.189	0.163	0.166
0.204	0.154	0.165
0.197	0.162	0.139
0.191	0.159	0.139
0.200	0.161	0.164
0.191	0.169	0.153
0.210	0.166	0.161
0.185	0.163	0.141
0.181	0.164	0.134
0.177	0.168	0.166
0.185	0.166	0.142
0.176	0.163	0.155
0.177	0.148	0.161
0.193	0.162	0.162
0.186	0.163	0.138
0.168	0.163	0.156
0.189	0.170	0.155
0.197	0.166	0.166
0.185	0.166	0.146
0.185	0.150	0.148
0.179	0.164	0.129
0.176	0.164	0.154
0.179	0.152	0.142
0.194	0.167	0.163
0.172	0.144	0.157
0.184	0.166	0.149
0.205	0.169	0.152
0.175	0.164	0.167
0.168	0.158	0.156
0.199	0.129	0.132
0.169	0.166	0.146
0.201	0.167	0.142
0.206	0.167	0.143
0.194	0.162	0.132
0.172	0.150	0.167
0.189	0.166	0.161
0.179	0.168	0.168
0.210	0.149	0.150
0.191	0.179	0.174
0.211	0.142	0.164
0.193	0.167	0.149
0.181	0.172	0.166
0.225	0.166	0.156
0.175	0.171	0.180

2016

I	J	K
N	0.154	0.148
O	0.139	0.120
	0.158	0.154
A	0.155	0.159
C	0.133	0.139
C	0.161	0.160
E	0.147	0.109
S	0.144	0.115
S	0.168	0.146
	0.159	0.131
	0.147	0.137
	0.168	0.162
	0.164	0.159
	0.145	0.121
	0.156	0.121
	0.149	0.117
	0.149	0.138
	0.144	0.165
	0.158	0.160
	0.159	0.150
	0.150	0.136
	0.157	0.121
	0.160	0.146
	0.162	0.149
	0.149	0.135
	0.121	0.153
	0.151	0.140
	0.161	0.156
	0.162	0.137
	0.160	0.148
	0.153	0.158
	0.161	0.138
	0.150	0.145
	0.161	0.119
	0.114	0.131
	0.162	0.131
	0.155	0.159
	0.142	0.149
	0.135	0.147
	0.160	0.160
	0.135	0.160
	0.154	0.162
	0.109	0.121
	0.155	0.159
	0.164	0.131
	0.138	0.130
	0.121	0.123
	0.152	0.147
	0.146	0.148
	0.161	0.164
	0.146	0.145
	0.121	0.166
	0.118	0.158
	0.164	0.161
	0.161	0.163
	0.111	0.166
	0.154	0.158

2018

I	J	K
0.231	0.151	0.155
0.217	0.130	Shield
0.215	Shield	Shield
0.205	0.165	Shield
0.191	0.167	Shield
0.183	0.156	Shield
0.183	0.160	Shield
0.172	0.157	Shield
0.161	0.171	0.151
0.185	0.163	0.140
0.176	0.157	0.152
0.192	0.161	Shield
0.173	0.166	Shield
0.176	0.146	Shield
0.176	0.150	Shield
0.173	0.156	Shield
0.194	0.156	0.145
0.165	0.156	Shield
0.185	0.165	0.162
0.167	0.164	0.156
0.176	0.149	0.153
0.168	Shield	Shield
0.162	0.144	0.157
0.156	0.163	0.152
0.164	0.159	0.157
0.175	Shield	0.157
0.165	0.141	0.142
0.170	0.142	0.152
0.157	0.160	0.156
0.167	Shield	0.153
0.175	0.141	0.157
0.162	0.160	0.147
0.173	0.157	0.147
0.159	Shield	Shield
0.173	Shield	0.129
0.166	0.164	0.147
0.177	0.163	Shield
0.186	0.165	0.159
0.156	0.163	0.132
0.173	0.162	0.141
0.169	0.160	Shield
0.167	0.163	0.144
0.159	Shield	Shield
0.158	0.162	0.141
0.170	Shield	0.143
0.156	0.166	0.134
0.162	Shield	Shield
N	Shield	Shield
O	0.169	Shield
	Shield	Shield
A	Shield	Shield
C	Shield	Shield
C	Shield	Shield
E	0.150	Shield
S	0.157	Shield
S	0.164	Shield
	0.151	0.157

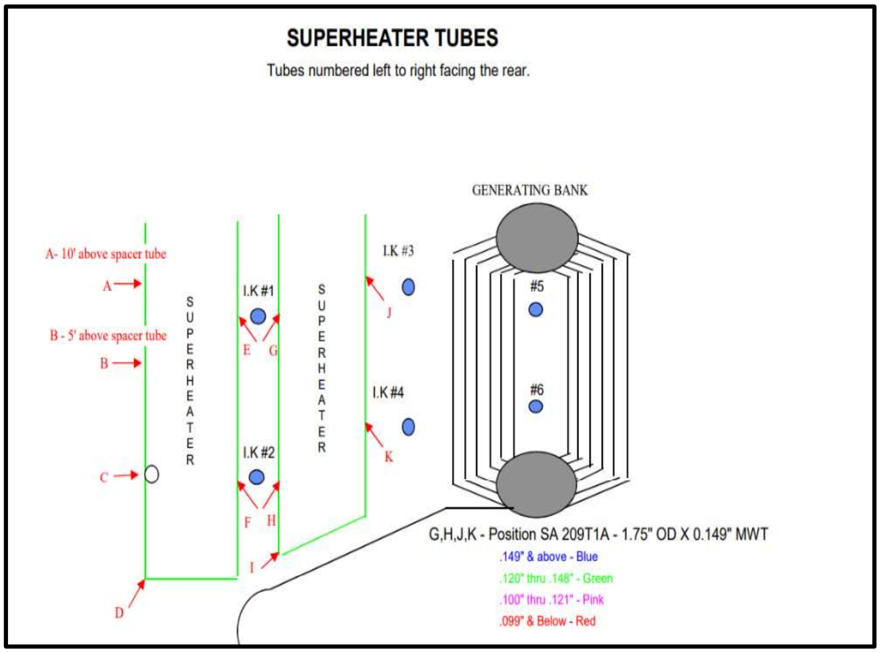
NOTE: No data was collected in 2020 or 2021 due to COVID

2. PROPOSAL AND RECOMMENDED SOLUTION

The recommendation is to replace the secondary superheater section. During the 1998 superheater tube replacement project both sections were replaced. A decision was made to upgrade the material and tube thickness on both sections of superheater. The primary superheater was upgraded from a 209 T1 material with a minimum wall thickness of 0.149” to a 213 T11 material with a minimum wall thickness of 0.198 wall thickness. These upgrades to have extended the primary superheater life span based on NDT results and analysis. Currently there are no indications showing in the Pink. Although there would be some savings in mobilization and common work and equipment needed to replace secondary superheater it is unknow how long the primary superheater will continue to operate without any impact to reliability. The last NDT inspection on the primary superheater showed some slight thinning on the tube bends only shown in D area.

2018 Primary Superheater

Tube #	A	B	C	D
1	0.205	0.206	0.229	0.181
2	0.221	0.217	0.203	0.182
3	0.214	0.216	0.205	0.185
4	0.218	0.217	0.203	0.191
5	0.219	0.217	0.219	0.179
6	0.211	0.218	0.216	0.191
7	0.211	0.212	0.205	0.191
8	0.211	0.212	0.219	0.182
9	0.225	0.217	0.202	0.193
10	0.214	0.210	0.204	0.177
11	0.213	0.213	0.207	0.182
12	0.216	0.216	0.208	0.184
13	0.213	0.212	0.213	0.180
14	0.211	0.213	0.216	0.175
15	0.210	0.206	0.223	0.173
16	0.211	0.213	0.229	0.173
17	0.214	0.217	0.223	0.175
18	0.208	0.212	0.207	0.193
19	0.214	0.209	0.211	0.185
20	0.214	0.208	0.217	0.190
21	0.215	0.213	0.225	0.170
22	0.213	0.215	0.202	0.190
23	0.215	0.215	0.213	0.181
24	0.223	0.221	0.210	0.182
25	0.204	0.218	0.218	0.177
26	0.220	0.223	0.214	0.189
27	0.219	0.207	0.206	0.185
28	0.220	0.210	0.201	0.198



Option	Capital Cost	Start	Complete
Replace the Secondary Superheater	$2,800,000	*MM YYYY*	*MM YYYY*
Alternative 1 Replace Primary and Secondary Superheater	$4,000,000	*MM YYYY*	*MM YYYY*

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

The first superheater was replaced after 16 years of service. The material of the tubes was changed from original design. The 1998 JP Industrial project report suggested the upgraded materials would possibly provide 20 years of service. The plant performs non-destructive testing to monitor the superheater

tube thickness. These readings are performed every two years and small repairs and preventive measures have been taken such as tube shielding to ensure maximum service is reached from the tubes. Below is a photo of an area that was replace and shielded. These repairs are scheduled and managed during the annual outage to minimize plant down time. Through consistent non-destructive testing a long data set has been collected on the entire unit and the secondary superheater is showing significant tube thinning. Nearly 80% of the tube leaks in the past 15 years have been located within the secondary superheater. About 60% of those leaks have caused forced down time on the unit while the other 40% were discovered during scheduled outages. The secondary superheater has operated longer than expected and has thinning throughout the entire pendant. Data shows ongoing maintenance of sections will no longer be a viable option as much of the pendant has reached the Pink measurement.

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 secondary superheater replacement project will consist of a multi-year project with the first year being the procurement of the superheater tubes. Year two will be the installation of the superheater as part of the annual Spring outage. The benefits to completion of this project will be increased reliability to the plant. Some O&M savings will be recognized in scaffolding costs, material and repair services.

A forced outage caused by a failed superheater tubes could extend many weeks. The estimated daily Power Supply outage cost for this facility is $69,700 (refer to 20220825 Thermal Daily Outage Cost Estimation Tool CONFIDENTIAL.xlsx).

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.]

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

This project will be managed within the normal Spring annual outage and will not have any additional impacts to Power Supply

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

Mitigation strategies have been in place for the past 5 years and will continue with smaller O&M projects and repairs. The NDT data is suggesting full tube replacement is now needed instead of isolated small sections of tube replacement or shielding. Due to COVID contractor restrictions no data was collected in 2020 or 2021. With historical data it the plant can expect to see more tubes in the all three sections of the secondary superheater to reach the Pink status and most likely some Red tube repairs will need to be made before this project is completed.

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.

Depending on material supply, procurement process will begin 6 – 12 months prior to the installation of the superheater tubes. A recent project that was completed at the plant with the economizer tube replacement had a similar approach. The economizer tubes were sources out of South Korea then shipped to Mexico for fabrication. The tube bundles were shipped to the plant a month prior to installation. CH Murphy was selected to install the economizer and work began two weeks prior to the beginning of the annual Spring outage and was complete in 4 weeks. This project will transfer to plant upon project completion.

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

This project aligns with providing safe and reliable renewable energy for our customers.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

This project will invest into a base load renewable facility that will increase plant reliability. The initial superheater was replaced after 16 years of service. The current secondary superheater has been in service for 23 years and will be at 26 years of service at the time of replacement. The plant can not operate without the superheater and data shows most of the tubes have reached a critical point needing to be replaced. Once replaced NDT testing will continue tracking the new tubes as before to ensure proper maintenance and planning is documented for future replacement.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Thermal Operations and Maintenance Manager

Plant Manager

Thermal Engineer
Kettle Falls Specialist
Supply Chain

2.8.2 Identify any related Business Cases

None

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Thermal and Operations Maintenance Manager

Plant Manager

GPSS Thermal Engineer

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

This project will be managed similarly past project such as the recent economizer replacement project. The Plant Manager will work closely with the Thermal Engineer and/or Project Contract Engineering to manage the procurement, fabrication and installation of the secondary superheater. Status reports and monthly update meetings will be made to the Thermal Operations and Maintenance Manager up until the installation process begins then weekly progress meetings will be used to keep the group informed.

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

This project will utilize Corporate Supply Chain Contract Change Order process for any changes to scope, schedule and budget changes. The project will follow the GPSS Department Project Delivery process. Issues or concerns will be brought to the GPSS Thermal Operations and Maintenance Manager for guidance and approval.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Secondary Superheater Replacement Project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Greg Wiggins Date: 8/20/2022

Print Name: Greg Wiggins

Title:	Plant Manager
Role:	Business Case Owner

Signature:		Date:	
Print Name:	Alexis Alexander		
Title:	Director of GPSS		
Role:	Business Case Sponsor		

Signature:	Thomas C Dempsey Digitally signed by Thomas C Dempsey Date: 2022.08.31 11:40:56 -07'00'	Date:	08/31/2022
Print Name:	Thomas Dempsey		
Title:	GPSS Thermal Ops & Maint Mgr.		
Role:	Steering/Advisory Committee Review		

KF_Fuel Yard Equipment_Replacement

EXECUTIVE SUMMARY

The existing system does not allow the plant to operate consistently with safe best practices, environmental stewartship and production. The fuel handling equipment operates at or beyond its absolute limit. In the early 1980's Washington State increased the legal hauling weight and the trucking industry transitioned from 48' trailers to 53' to increase their payload. This change created a number of production and safety challenges for the plant operations and contractor support. The system does not meet current environmental regulations for visibility and particulate matter (PM) emissions for intermittent periods. Although the primary drivers for the project are safety, environmental, and reliability, we do expect a decrease in O&M. With all benefits included, Financial Planning and Analysis has concluded that this is a prudent project. The project will proceed over a two year period with $12 million in 2019 and $10 million in 2020. (7/8/2021 Update: *Project timeline has been extended and adjusted and the current plan will continue into 2021 with the underground utilities installed, major equipment purchased and truck dumpers commissioned. 2022 will be construction of conveyance, processing and control buildings and installation of the hog and disc screen*.)

Replacing the major fuel handling equipment will create a safer system for employees and contractors as the new dumpers will be designed to lift current truck lengths and weights. The major equipment will be designed with covers and passive dust control utilizing new dumper technology and conveyance covers. (*7/8/2021 Update: Scope has been reduced to reduce project costs by changing the truck route, eliminating a pass through travel route, reduction of an enclosed processing building, eliminating a conveyor through a more compact layout, eliminating a new power supply from the distribution line near the plant site and delay of replacing the existing #3 fuel conveyor*)

This project will impact customers in service code Electric Direct jurisdiction Allocated North serving our electric customers in Washington and Idaho.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Greg Wiggins*	*Initial draft of original business case*	*05/01/2018*	
1.0	*Thomas Dempsey*	*Edit Draft / Executive Summary*	*07/03/2018*	*Added content*
1.1	*Greg Wiggins*	*Edit Approved Business Case to new Template*	*07/08/2021*	*New Template / Update major project changes Scope, Schedule and Budget*

KF_Fuel Yard Equipment_Replacement

GENERAL INFORMATION

Requested Spend Amount	$22,000,000
Requested Spend Time Period	*2 year (7/8/2021 Update project will be 5 year)*
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Greg Wiggins | Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Execution *(7/8/2021 Update project is in execution phase)*
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

The major fuel yard equipment being considered for replacement includes the truck dumpers, fuel hog, truck scale, and conveyance systems.

Truck Scale - The truck scale is used to account for the quantity of fuel received from each truck delivery. The truck drivers scale in upon arrival to the site and the scale out after completing the unloading process.

Truck Dumpers - The truck dumper receives the delivered fuel by elevating the trailers. Fuel exits the rear of the trailer into a receiving housing.

Fuel Conveyors - Fuel conveyers move the fuel from the truck dumpers to a metal detection system, then to the fuel hog system and finally out to the fuel yard.

Hog and Disc Screen - The fuel hog is a device that clarifies and conditions the fuel so that it is the proper size required for optimum combustion.

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

There are three key components that comprise the business problem presented by the current fuel yard.

1. Safety
2. Environmental
3. Reliability

These three components are summarized as follows:

The Kettle Falls Generating Station is a biomass fueled power plant that processes on average 500,000 green tons of waste wood from area sawmills. The wood delivered to the facility is trucked in by contractors utilizing semi-trucks and chip trailer. On average the plant received 65-80 loads of fuel each day with surges to 100 deliveries in a 24 hour period.

The plant's original design was just prior to Washington State increasing the legal haul lengths and weights. All the equipment was designed for 48' trailers and the new law change in 1985 allowed drivers to haul with 53' trailers. When the drivers enter the facility the load is weighed on a State certified scale to determine amount of fuel being delivered. The longer trailers do not completely fit on the scale without the drivers lifting the tag axle on the trailer. The plant's delivery tracking system captures the gross weight of the truck and trailer into the 3Log financial interface application. Through this system vendors and suppliers are paid for their services. Due to the longer trailers and short scale drives can "cheat" the system by not positioning the load correctly on the scale. Each load is reviewed through the 3Log (TWA) Truck Weight Analyzer. When an infraction is found the surveillance video is reviewed and sent to the hauling company for reconciliation. Manual adjustments are made in the system to ensure proper payment to the supplier.

Truck was intentionally positioned short on the scale.

TWA show drivers manipulating the scale due to being overloaded.

The fuel is offloaded truck trailers into the receiving hoppers via a truck dumpers. The wood is then conveyed, screened and sized prior to being transferred out to the fuel inventory pile. The Fuel Equipment Operators then manage the fuel inventory utilizing D10 Cat dozers to stack out incoming fuel and stage inventory to be processed in the plant.

Due to the higher legal hauling limits in Washington the longer truck/trailer configurations require the truck drivers to unhitch the trailer from their trucks. This unhitching process not only increases truck turnaround time and increases hauling costs to plant, it adds a difficult step. Although not the primary factor, a contractor fatality in 2013 occurred while going through this step in the process. One driver was attempting to unhitch his trailer from the truck and was working with another driver to get the hitch pin released when the accident occurred.

KF_Fuel Yard Equipment_Replacement

After the load is raised into the air and the fuel is discharged out of the back of the haul trailer into the truck receiving hopper a large plume of dust often launched into the air and then carried in the wind off the plant site. After the wood discharges out of the truck receiving hopper it is transferred via conveyor belt to a disc screen and hammer hog to be properly sized and then discharged onto the hog storage area.

Both Safety and Environmental regulations require that PM be reasonably controlled for worker safety, air quality and visibility. All emissions should be managed on-site.

The fuel yard is subject to a very corrosive environment due to the wet wood being in contact with the equipment. The years of rusting has caused failure to metal conduit and structural steel. The metal support structure of the truck receiving hoppers has rusted through to the point of being completely cracked through. Welded plates have been installed to affected areas on the truck receiving dumpers. Many of the electrical conduits are rusted through and need replacement.

The system is currently running at maximum capacity with fuel spilling over the edges of the conveyance system, the disc screen is not operating at the proper throughput as a significant amount of proper sized fuel is carried over the disc screen into the hammer hog. The over feeding of material into the hog creates excessive wear on the hammer hog grates and hammers.

With an average of 80 semi loads delivered each day and over 25 sawmills depending on the fuel yard at Kettle Falls to be in full operation there is tremendous pressure in keeping the system running. Area mills store the fuel purchased by Avista in storage bins and can only hold the waste wood for a few days and sometimes only hours before the backup of wood begins to cause production issues at the mill. When product flow out of the mill is not managed well suppliers may begin to look for other options to move their waste to more reliable markets. Another important detriment to not keeping fuel moving efficiently is that as more fuel inventory builds at the supplying mill, the resulting Moisture Content increases as well as the opportunity for contamination from rock and other “non-spec” materials. It is important to keep the KFGS fuel yard operating with minimal downtime to provide good service and quality control to the supplier’s milling operations. It is critical to the reliability of both the KFGS plant and its supply chain.

In 2017 a team was assembled including the Thermal Operations and Maintenance Manager, Fuel Manager, Plant Manager, Thermal Engineering and plant staff. The team worked with outside engineering firm WSP to evaluate the fuel yard equipment and explore options. The team also traveled to two new biomass plants to gain knowledge of new equipment and process. This information along with the support of WSP allowed the team to evaluate a number of options.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Major drivers for this project were Asset Condition and Mandatory & Compliance. Installing the new fuel yard equipment with a higher capacity design and environmental dust control measures will be a benefit to the plant and neighbors. Moving truck through the yard quickly reduces trucking costs. This project will decrease truck turn time.

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

The plant experienced a fatality of a contract driver that would have been completely avoided if the truck dumpers were able to lift the current truck weights and lengths. A few years later another driver was injured on plant site attempting to manually offload his overloaded trailer when a bunch of fuel slid out of the trailer and buried the driver crushing his hip and knee. This project will make for a safer facility for our contractors.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Truck weight analyzer and the weighwiz system will be able to accurately capture the delivery with the new longer scales. Truck turntime will decrease as drivers will no longer need to lift tag axels, disconnect the truck and trailer or use one scale for inbound and outbound scaling.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

In 2017 a team was assembled including the Thermal Operations and Maintenance Manager, Fuel Manager, Plant Manager, Thermal Engineering and plant staff. The team worked with outside engineering firm WSP to evaluate the fuel yard equipment and explore options. WSP presented the Team a feasibility study with options to consider. That document is located in the project file.

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

The team selected option #3 and in replacing the major equipment in a new layout. Below shows the four options, matrix score, CAPX and OPEX.

This feasibility study includes estimated CAPEX, OPEX and MTC, and discusses the pros and cons of the scenarios analyzed. The possibility of an increase in generation of 15 MW was considered when sizing the equipment. Some equipment drives may require upgrading, as such the equipment was sized for the increase.

Based on extensive in-person meetings with the Avista project team, four scenarios were examined to meet the requirements of the plant; results of the analysis for the scenarios are shown in the table below.

	System #1: Existing and Rebuilds	System #2: Existing Layout c/w new equip	System #3: New Layout c/w new equip	System #4: New System c/w Covered Building
Avista's Ranking Calculator by System	370.00	296.00	123.00	143.00
CAPEX (2017 $)	$4.2 M	$9.5 M	$21.6 M	$30.1 M
OPEX (average over 20 years, 2017 $)	$1,095,000	$1,121,000	$665,000	$998,000
MTC (average over 20 years, 2017 $)	$829,000	$782,000	$405,000	$432,000

2. PROPOSAL AND RECOMMENDED SOLUTION

The four options were discussed and doing nothing has been the approach for a number of years. Maintenance costs have increased with equipment failure to the live bottom gear boxes, dumper cylinders and lifting deck. Modifications are being made to equipment due to obsolete equipment is no longer available. This approach will see continued breakdown maintenance, reduction in fuel yard reliability and continued risks around safety and environmental litigation.

Option 1 includes major rebuild of the existing equipment. The truck dumpers would have mechanical and support rebuilt, some conveyors would be sped up to the maximum allowed throughput, hog and disc screen would be rebuilt, the power distribution, motor control centers and PLC's replaced, all the electrical hardware in the yard would be replaced. This option would not change the operations of the fuel handling system. Safety and environmental concerns would remain unchanged. The truck scaling issue would still remain. The work would create major disruptions to our suppliers as the work and repairs could not be done without interrupting delivery schedules for days and weeks at a time. Fuel would have to be diverted to other consumers with the risk of losing the contracts in the future.

Option 2 included replacing key equipment with one new scale, two dumpers, two conveyors, hog and screen in the existing location. This option would not address the congested truck route that currently exists with one scale. The fuel conveyor angle would remain the same and would not solve the sliding winter fuel issues experienced by the plant operations staff all winter long. This option would disrupt dilveries and cause major fuel disruptions to the sawmills and carriers under contract. Temporary truck dumpers would have to be installed and significant fuel curtailment and deverting would be required.

Recommendation is to pursue Option 3 that includes relocating new equipment to a different location in the fuel yard. This approach would allow the current system to operate while the new system is constructed and commissioned. The layout would reduce crossing traffic issues with the semi trucks. A new longer inbound and separate outbound scales would eliminate the scaling issue as sensors would not allow a driver to scale in unless the truck was positioned correctly on the scale. The two new truck dumpers would be larger in size which would allow the lifting of both the truck and the trailer. This would reduce truck turnaround time and eliminate the hazard identified in the driver fatality. The new dumpers would incorporate a dust containments systems to reduce fugitive dust during the offload. New conveyors would be larger to accommodate higher throughput. The higher capacity belt system would reduce laborious shoveling of spilled fuel. The incline of the new belts would reduce winter frozen fuel from sliding on the conveyor belts. The disc screen would be larger in size for better screening efficiency and reduce hog operation to only oversized material. The upgraded stack out fuel conveyor system would strategically move the fuel to three locations reducing Caterpillar dozer fuel consumption and yearly time base maintenance. A new control tower and power supply would eliminate the electrical deficiencies with the current system.

Option 4 is the same as option 3 with the addition of a covered fuel storage area. Covering the fuel could reduce moisture content during the winter months. Power Supply and Asset Management explored the additional cost benefit and this option did not make financial sense.

Option	Capital Cost	Start	Complete
Existing Rebuild and Minor Upgrades	$4,200,000	10/2020	6/2023
Existing Layout with New Equipment	$9,500,000	10/2020	6/2023
New Layout with New Equipment	$22,000,000	10/2020	6/2023
New Layout with New Equipment and Covered Yard	$30,100,000	10/2020	6/2023

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

The Team worked with WSP and evaluated ever component of the fuel handling system. All of the current equipment was ranked using the GPSS project ranking matrix and the scores were used to determine what system would meet the criteria set for the project. Below is an example of the analysis that was done for every part of the fuel handing system.

Avista KFGS Woodyard Study — **Equipment Alternatives and Ranking Table**

WSP Ref #: 171-11373-00/185233A — Date: 10/19/2017

			Scope of Work Description & Avista Rating			
Item #	**Equipment Name**	**Wt**	**System #1: Existing**	**System #2: Existing Layout c/w new equip**	**System #3: New Layout c/w new equip**	**System #4: New System c/w Covered Building**
1	**Truck Scale(s)**		- maintenance	- new single scale and data recorder	- new dual scales and data recorder	- new dual scales and data recorder
	Personal or public safety	4	3	2	0	0
	Potential environmental issue	4	0	0	0	0
	Regulatory mandate	3	0	0	0	0
	On-going maintenance issue wt:3	3	2	0	0	0
	Decrease future operating costs	2	2	0	0	0
	Increase efficiency (revenues - power usage)	1	1	1	0	0
	Obsolete parts and equipment	1	0	0	0	0
	Risk of equipment failure	4	2	2	0	0
	Customer Value	3	2	1	0	0
	Sub-total		37	20	0	0

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

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

The project will be a two year project with engineering, design and major equipment procurement in the first year followed by construction and commissioning the following year. The beakdown is a two year period with $12 million in 2019 and $10 million in 2020. (7/8/2021 *The project will run into 2022 with a possibility of 2023. The project originally requested 22 million over two years, CPG has only funded 20 million. When presenting the request I failed to load the project during the estimating process so AFUDC and Loadings were not added at the time of the request. These two issues have a 4 million shortfall in project funding. During construction the underground excavation process discovered unforeseen challenges with foundations and underground piping that resulted in re-engineering and changes. Cost and overruns form the phase one resulted in the Team drastically cutting scope to manage budget. Changes included re-routing the truck area, removing the enclosed processing building,* *repurposing some existing equipment, redesigning the layout to eliminate an entire conveyor and postponing replacing the final stackout conveyor.)*

[Offsets to projects will be more strongly scrutinized in general rate cases going forward *(ref. WUTC Docket No. U-190531 Policy Statement)*, therefore it is critical that these impacts are thought through in order to support rate recovery.

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

This project will require some short outages that will be managed within the normal Spring outage for accommodate some conveyor transitions to the current process and power supply connections. There may be some curtailment needs with our contract mill to stop wood deliveries. This project will not cause any plant reliability issues with Power Supply.

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

The project will run into 2022 with a possibility of 2023. The project originally requested 22 million over two years, CPG has only funded 20 million. When presenting the request I failed to load the project during the estimating process so AFUDC and Loadings were not added at the time of the request. These two issues have a 4 million shortfall in project funding. During construction the underground excavation process discovered unforeseen challenges with foundations and underground piping that resulted in re-engineering and changes. Cost and overruns form the phase one resulted in the Team drastically cutting scope to manage budget. Changes included re-routing the truck area, removing the enclosed processing building, repurposing some existing equipment, redesigning the layout to eliminate an entire conveyor and postponing replacing the final stackout conveyor. The Team intentionally stopped work with the contractor Greenberry to reevaluate the costs. The installation was rebid to a number of contractors and a change was made with awarding the work to Knight Construction as a lower cost.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

(7/8/2021 *Update All of the underground work is complete minus two conveyor foundations that will be installed after the current truck dumpers are demolished. All major equipment is purchased and onsite minus the hammer hog and transition chute and the #3 stack out conveyor. The fueling building is procured and will be installed in September. The truck dumpers will be commissioned mid July. All the critical electrical equipment has been purchased. The project has two options for 2022 one being a complete project to the #3 conveyor and the other a hot feed option which could see some of the equipment in Q3 of 2022 either way. If the hot feed option is selected then the remaining equipment would become operational in 2023.)*

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

Ketlle Falls is a renewable generating site and this project aligns with providing reliable renewable energy to our customers. This project will increase Safety and be good for the environment and neighbors.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

This project was subjected to a rigorous evaluation of each major piece of equipment and is documented in the WSP Feasibility Study. The project has worked closely with the Steering Committee that is represented by GPSS, Environmental and Power Supply. The project is being lead by GPSS Project Manager and the Team meets regularly to discuss scope, schedule and budget.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

GPSS Thermal Operations and Maintenance Manager

Environmental

Power Supply

Contracts and Supply Chain

Plant Staff

2.8.2 Identify any related Business Cases

KF 4160 V Station Service replacement (new request in 2022)

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Thomas Dempsey - GPSS Thermal Operations and Maint Mgr

Darrell Soyars – Environmental

Scott Reid – Power Supply

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

GPSS Core team will follow the Department Project Management protocol. There will be monthly Steering Committee meetings to discuess issues or concerns. Updates will be shared on an as needed basis between monthly status meetings.

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

Chage orders will follow Supply Chain contracting protocol based on financial signing authority.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Fuel Yard Equipment Replacement project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Greg Wiggins Date: 7/8/2021
Print Name: Greg Wiggins
Title: Plant Manager
Role: Business Case Owner

Signature: Andy Vickers Date: 7/9/2021
Print Name: Andy Vickers
Title: Director GPSS
Role: Business Case Sponsor

Signature: ____________ Date: ____________
Print Name: ____________
Title: ____________

KF_Fuel Yard Equipment_Replacement

Role:	Steering/Advisory Committee Review

KF - 2022 ID Fan & Motor Replacement

EXECUTIVE SUMMARY

The induced draft (ID) fan at Kettle Falls Generating Station is a critical component in the combustion process. The ID fan pulls a draft on the combustion fire box and discharges the flue gas through the electrostatic precipitator and out the stack. The ID fan is considered a “dirty” fan in which it is operating with fly ash in the flue gas. The fly ash is abrasive on the internal components of the boiler. The fan shroud, case, cage and dampers are requiring significant annual maintenance each year to build up the worn area. The fan motor reaches max amperage during wet wood combustion and often hits the max fan damper position.

The proposed solution involves replacing the ID fan and motor to appropriately accommodate the needs of the plant. The proposed solution includes implementing a variable frequency drive (VFD) which addresses fluctuations in loads expected from fuel moisture and the ability to operate in a flexible EIM market. The VFD also improves fan and motor efficiency during operations minimizing the wear that has become an annual maintenance concern. The change in equipment will precipitate ducting changes and potential foundation modifications. This solution has been the result of a collaboration between plant management (Greg Wiggins and Patrick Lutskas) and plant technical staff. Project scope has also been reviewed and approved by the program manager (Thomas Dempsey). The proposed solution is budgeted to cost $1,650,000. The investment of the ID fan and motor replacement (along with a VFD) will eliminate the costly repairs which have only allowed the unit to limp from year to year. This is not only necessary to ensure the plant is able to operate under full load with the expected range of fuel quality. All of this adds value to the customer through improved operations and minimized maintenance costs. There has been significant work with Air Stream, a fan manufacturer, in the testing, sizing and cost estimating for this project. Options and recommendations have been captured and this project has been well scoped and estimated.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Derek Babine	Initial draft of original business case	05/24/2022	Executive Summary Only
1.0	Derek Babine	Updated to include project justification	08/24/2022	Full business case

GENERAL INFORMATION

Requested Spend Amount	$1,650,000
Requested Spend Time Period	2 years
Requesting Organization/Department	K07 / GPSS
Business Case Owner | Sponsor	Derek Babine | Alexis Alexander
Sponsor Organization/Department	K07 / GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

The induced draft (ID) fan at Kettle Falls is a part of the flue gas system which pulls a draft on the combustion fire box and discharges the flue gas through the electrostatic precipitator and out the stack. The ash in the fuel gas is abrasive which has caused significant wear to all of the fan components and case. The motor driving the fan is also suffering from being overworked during times of poor fuel quality and high demand on the system at full load. This sometimes results in a need to limit the plant's output because the motor cannot keep up with the material that the fan is processing. Currently, the plant uses inlet guide vanes (or dampers) to regulate the flue gas entering the fan chamber. This ensures that the fan does not get overloaded. These dampers are only able to aid the process of the flue gas so much before the motor is maxed out and the plant is forced to drop megawatts.

In short, the mounting maintenance costs for the fan and the inability for the motor to keep up with the volume and quality of flue gas led to higher costs and lost generation.

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

The induced draft fan faces significant maintenance nearly every annual outage as a result of fan blades wearing down from fly ash abrasion. Usually, these repairs come in the form of welding additional material on the blades and grinding it down to maintain the effectiveness of the fan. This is costly and difficult work which does not address the root problem, that the fan is nearing the end of life. The motor also maxes out in amperage and is unable to accommodate the flue gas flow under certain conditions.

1.2 Discuss the major drivers of the business case

The main driver of the business case is certainly asset condition but there is also a performance and capacity issue as the fan and motor age, they are no longer able to process flue gas to the degree necessary under certain operating conditions which can limit the capacity of the plant.

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

The fan and motor limp along each year thanks to extensive maintenance but the effective longevity of this strategy is unknown. If the fan has severe enough wear, the plant would be forced to come offline due to an inability to process flue gas. While the repair costs continue to build, there is also the possibility of unplanned plant downtime if the fan or motor needs to be replaced in the case of equipment failure. Additionally, this project has already been deferred for several years.

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 a result of the proposed project, the plant will see a large reduction in annual maintenance to the fan for the next 10-20 years. Any repairs will be minimal by comparison. Also, the plant’s efficiency and increased productivity will be shown by amperage numbers which do not max out on the motor and steadier plant output even during times of poor fuel quality.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

N/A

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 graph above shows a typical instance of the plant ramping up to nearly full load (MWs shown in purple) with the damper position maxing out (orange trend) as the motor tops out in amperage (shown in blue). Once the amps on the motor plateau around 105 amps, the other parameters are forced to plateau as well. This shows how the motor can be a limiting factor in the plant's MW output.

The photos above show the kind of repairs that were necessary during the spring outage of 2021. There are extensive weld repairs on large sections of the fan blades and plate metal additions to replace material that has been eroded during the life of the fan. This kind of repair has been routine over the last several years and is costly as it is very time-intensive work. The blades and periphery continue to see deterioration each year. Ideally another major repair job (as shown above) can be avoided before the fan is replaced.

2. PROPOSAL AND RECOMMENDED SOLUTION

The proposed solution involves replacing the ID fan and motor to appropriately accommodate the needs of the plant. The proposed solution includes implementing a variable frequency drive (VFD) which addresses fluctuations in loads expected from fuel moisture and the ability to operate in a flexible EIM market as well as being able to pick up generation gaps which could result from the proposed plant addition. The VFD also improves fan and motor efficiency during operations minimizing the wear that has become an annual maintenance concern. Power consumption of the fan motor will be minimized by having the VFD adjust the motor's output. The change in equipment will precipitate ducting changes and potential foundation modifications.

Option	Capital Cost	Start	Complete
Replace the ID fan, motor and add VFD	$1,650,000	10/2022	06/2024
Replace the ID fan and motor (no VFD)	$1,150,000	10/2022	06/2024

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

The main data points which were considered in preparation of this capital request are the limitations to plant performance and output which have been manifested in PI data and control room rounds sheets over the past several years. This data will also allow tracking of improvement once the solution is implemented. Although the problems have exhibited themselves for many more years, this most recent data shows the immediacy of the issue and regularity of limited operation. Maintenance and repair costs alone have pushed the need for these components to be replaced into the foreground. Both the concerns for hampered generation and the concern about potential downtime due to asset conditions have also been considered. In regard to determining whether to implement a VFD into the system, the power savings achieved by replacing dampers with a new drive and the pay-back period for this option make this solution desirable. Additionally, the VFD will be able to provide improved ability to make up for potential losses in generation related to the plant upgrade and flexibility of operation in unideal fuel conditions which provide additional power consumption cost savings.

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 ID fan and motor replacement project will consist of a multi-year project with the first year being the procurement of the fan, motor and VFD. Year two will be the installation of these components as part of the annual Spring outage. The year that these components are installed there will be no need for fan repair which will be reflected in reduced O&M costs.

A complete failure of the ID Fan could extend many weeks. The estimated daily Power Supply outage cost for this facility is $69,700 (refer to 20220825 Thermal Daily Outage Cost Estimation Tool CONFIDENTIAL.xlsx).

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

This project will be managed within the normal spring annual outage. The VFD will save on station power which will increase power out to our customers.

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

One alternative is to let the assets run to failure. This is a risky option for several reasons most notably the potential for unplanned plant downtime. It also would result in increasing O&M costs in the coming years with the replacement still required at the point of failure.

Another alternative is to not implement a VFD into the system and essentially just replace the components in kind with what is currently installed. This alternative is viable but could present the plant with some of the issues which are currently problematic such as limitations during poor fuel quality and wasted energy consumption when dampers are heavily utilized. The VFD addresses these issues making it a more desirable solution.

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.

Procurement of components for this project will begin in mid-summer of 2023 due to long lead times on items such as the VFD and ID fan. Design considerations and consulting have already begun with the fan and VFD supplier and these will continue up and through the point of purchase. The ID fan, motor and VFD will all be installed during the annual spring outage timeframe in 2024 and will be used and useful upon completion when the plant comes back online following the outage.

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

This project aligns with providing safe and reliable renewable energy for our customers.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

This project invests into the long-term life of the plant and takes into consideration modifications related to plant expansion. This solution resets the clock on extensive fan repairs and increases the efficiency of the plant by implementing new technology which will allow the plant to be more adaptable to varying fuel quality and generation setpoints. Although the plant has been able to get along in the current state, it is not a sustainable solution and this work will not only improve performance but provide minimize maintenance on these components for decades due to technological advances in fan and drive design.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Thermal Operations and Maintenance Manager

Plant Manager

Thermal Engineer

Kettle Falls Specialist

Supply Chain

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Thermal and Operations Maintenance Manager

Plant Manager

GPSS Thermal Engineer

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

The Plant Manager will work with the Thermal Engineer and/or Project Contract Engineering to manage the procurement, fabrication and installation of the ID fan, motor and VFD. Status reports and monthly update meetings will be made to the Thermal Operations and Maintenance Manager up until the installation process begins then weekly progress meetings will be used to keep the group informed.

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

This project will utilize Corporate Supply Chain Contract Change Order process for any changes to scope, schedule and budget changes. The project will follow the GPSS Department Project Delivery process. Issues or concerns will be brought to the GPSS Thermal Operations and Maintenance Manager for guidance and approval.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls ID Fan & Motor Replacement Project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Derek Babine	Date:	8/24/2022
Print Name:	Derek Babine		
Title:	Mechanical Engineer		
Role:	Business Case Owner		
Signature:	Alexis Alexander Digitally signed by Alexis Alexander Date: 2022.09.05 10:39:26 -07'00'	Date:	
Print Name:	Alexis Alexander		
Title:	Director of GPSS		
Role:	Business Case Sponsor		
Signature:	Thomas C Dempsey Digitally signed by Thomas C Dempsey Date: 2022.08.31 11:04:59 -07'00'	Date:	08/31/2022
Print Name:	Thomas Dempsey		

Title:	GPSS Thermal Ops & Maint. Mgr.
Role:	Steering/Advisory Committee Review

Little Falls Crane Pad and Barge Landing

EXECUTIVE SUMMARY

The existing crane pad/trash boom anchor at Little Falls are at their end of useful life. The sheet pile wall is severely rusted and deteriorating in several locations including where it adjoins the river bottom. The foundation is eroding to the point where if too much weight was put on the crane pad there could be complete failure and equipment could fall into the forebay. The only way to currently use the crane pad is to adjust outriggers far enough away from the water's edge which causes partial obstruction to Spokane Indian Tribe's Martha Boardman Rd.

A new crane pad/barge landing/trashboom anchor system needs to be designed and constructed. This is a critical path project to be prioritized as such to prepare future and safe access for the Little Falls Intake Project (headgates, supporting structure, motors, and trash rake), as well as the Little Falls Controlled/Gated Spillway Project to repair concrete and replace flashboard function on the spillway dam. The current off-loading and staging causes obstruction and congestion to the road as well as the proximity to the roadway increases safety hazards for workers and site personnel.

The Crane Pad and Barge Landing will cost approximately 4 million dollars to design, engineer, and construct. This also includes demolition and removal of the existing crane pad and trash boom as well as environmental protection and mitigation.

This project benefits Avista's customers as the risk of continued use of the current crane pad could result in failure… leading to potential loss of human life and/or serious injury, damage to property and equipment, and lack of access to maintenance and construction projects.

Little Falls Crane Pad and Barge Landing

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Mac Mikkelsen*	*Executive Summary*	*05/31/2022*	
2.0	*Mac Mikkelsen*	*Draft*	*09/01/2022*	

GENERAL INFORMATION

Requested Spend Amount	$3,000,000
Requested Spend Time Period	*2 years*
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Mac Mikkelsen | Alexis Alexander |
Sponsor Organization/Department	GPSS
Phase	Choose an item.
Category	Choose an item.
Driver	Choose an item.

1. BUSINESS PROBLEM

[This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement]

1.1 What is the current or potential problem that is being addressed? The current crane pad is failing. There isn't enough room to get off of the Spokane Indian Reservation Road to utilize the crane. The Trash Boom Anchor and Trash Boom do not work correctly due to the configuration and need to be replaced.

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 crane pad will fail eventually, and it will be more expensive to fix than replace. It poses a public and employee safety concern. A new crane pad, landing, trash boom anchor, and trash boom will be much more efficient, safety for everyone, and increase performance and reliability which will benefit our customers. This project is also critical to be able to complete futures projects at the intake and spillway which will also provide customer service quality.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred. We need to replace the whole system as soon as possible as the current system is failing. If we neglect these assets they will fail, and we won't be able to access our forebay for maintenance and future capital projects. In the long run it will be more expensive, and the neglect may lead to a danger to the public, our employees and ultimately our 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. A new crane pad, landing, trash boom anchor and trash boom will provide a safer, more efficient system, and less likelihood of complete failure based on the new condition.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Geotech work was completed in 2022 to show the stability of the ground if a new crane pad and landing were to be installed. The current pilings are rusted out and losing their foundational support and must be removed.

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 is available in the GPSS library.

2. PROPOSAL AND RECOMMENDED SOLUTION

It is recommended that the Crane Pad, Landing, Trash Boom Anchor, and Trash Boom be fully replaced. The old ones have more than exceeded their useful life. A replacement of this entire system will better suit the needs of plant operations, reduce employee and public safety concerns, and provide longer resilience and use for future projects and maintenance.

Little Falls Crane Pad and Barge Landing

Option	Capital Cost	Start	Complete
Replace Crane Pad, Landing, and Trash Boom System	*$3,000,000*	*06/2022*	*12/2023*

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

- *Better access to forebay*
- *Safer conditions for employees and the public to be able to get off of a busy road (that is not Avista's at the bottom of hill)*
- *Reduction of maintenance and constantly adjusting the current trash boom as there will be a better design with the new*
- *The current pilings are failing, and the loss of foundation may lead to employee safety concerns, public safety concerns, and environmental concerns*

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.**

Thee investment will increase efficiency and reduced costs by providing a safer and more reliable landing to work from and manage the trash boom.

[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.

Construction on the new crane pad, landing, and trash boom system may cause some concerns for operations – specifically to the ability to generate electricity at Little Falls due to immediate proximity of the powerplant.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative. An upstream location for this was discussed, but Avista doesn't own the land where this could go as it's on the Spokane Indian Reservation.

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.

Initial design began in July 2022 and construction will begin in 2023. The project and system will be become used and useful by 2024.

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

Replacing the crane pad, landing, and trash boom system is the responsible thing to do. It aligns with our mission as it sets us up to be able to provide reliable and affordable electricity 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

It is an appropriate amount to replace the asset and would be well worth the cost as the current asset is failing.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

GPSS Operations, GPSS Engineering and Dam Safety, GPSS Mechanic Shop, Electric Shop, and Relay Shop, Telecom Shop, Environmental Affairs, Power Supply, Energy Resources, System Operations

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

Manager of Hydro Operations, Director of GPSS, Manager of MS and Electric Shop, Manager of Civil and Mechanical Engineering

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

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

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Little Falls Crane Pad and Barge Landing 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: Mac Mikkelsen Digitally signed by Mac Mikkelsen Date: 2022.09.01 09:37:46 -07'00' Date: ________________

Print Name: Mac Mikkelsen

Title: Manager Hydro Ops

Role: Business Case Owner

Signature: Alexis Alexander Digitally signed by Alexis Alexander Date: 2022.09.02 14:54:04 -07'00' Date: ________________

Print Name: Alexis Alexander

Title: GPSS Director

Role: Business Case Sponsor

Signature: ________________ Date: ________________

Print Name: ________________

Title: ________________

Role: Steering/Advisory Committee Review

Little Falls Plant Upgrade

EXECUTIVE SUMMARY

The Little Falls Plant Upgrade Program began in 2012 and in 2020, is in the final phases of implementation. With three project components left (Plant Sump, Drain Field, and Panel Room Roof/Enclosure for the new controls equipment) the vast majority of the project scope has been completed and risks mitigated. The remaining work has very little risk exposure and minimal impact on the plant's current operations.

Driven initially by the age of the infrastructure at the plant, Alternative 3, a full replacement of all four generatring units and all obsolete supporting equipment, was selected, implemented, and put in service. Given as how the program is nearly complete and decisions have already been made in regards to the following, no additional details regarding solution recommendations, risk of failure to implement, schedule significance or benefit to customers are provided at this time.

The remaining programmed work is being scheduled into 2021 as a response to internal resource constraints, and therefore, this business case and its remaining activities are subject to this Business Case Refresh exercise.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Brian Vandenburg*	*Initial draft of original business case*	*2.14.17*	*Signed/approved*
1.1	*Kara Heatherly*	*Conversion to new format*	*6.20.20*	*Includes budget update*

GENERAL INFORMATION

Requested Spend Amount	$56,100,000
Requested Spend Time Period	10 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Brian Vandenburg | Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

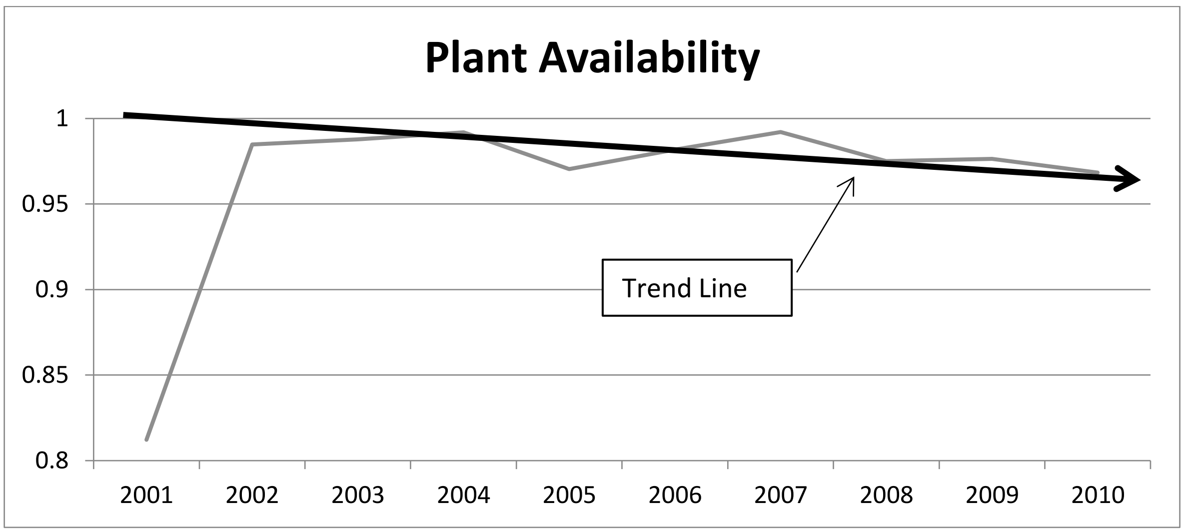
1.1 What is the current or potential problem that is being addressed?

The existing Little Falls equipment ranges in age from 60 to more than 100 years old. Little Falls experienced an increase in forced outages over the past six years, increasing from about 20 hours in 2004 to several hundred hours in the past several years, due to equipment failures on a number of different pieces of equipment.

Once the business case is complete, a study of forced outages at the plant over a 5 year period could be taken and measured against the pre-construction outage numbers to determine if plant availability has increased and the business case objective met.

1.2 Discuss the major drivers of the business case and the benefits to the customer

The major drivers for the Little Falls Plant Upgrade are available and reliability. See the graph below that illustrates the trend line for availability at Little Falls.



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

See alternatives analysis narrative conducted at project onset in section 2.1 for additional details.

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.

See alternatives analysis narrative conducted at project onset in section 2.1 for additional details.

Option	Capital Cost	O&M Cost	Start	Complete

Alternative 3: Preferred	*$56,100,000*	*$0*	*2012*	*2021*
Status Quo	*$0*	*$150,000/yr*		
Alternative 1	*$5,000,000*	*$20,000/yr*		
Alternative 2	*$83,000,000*	*$0*		

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

Summary of alternatives:

Status Quo: Forced outages and emergency repairs would continue to increase, reducing the reliability of the plant. Each time a generator goes down for an emergency repair, Avista is forced to replace this energy from the open market which leads to higher energy costs.

It is expected that the O&M costs would continue to climb as more failures occurred. This may also require personnel to be placed back in the plant to man the plant 24/7 in order to respond to failures. Again, increasing expenses for the project with no benefit in performance.

Alternative 1: Replace Switchgear and Exciter: This would replace the two items that are currently responsible for the majority of the forced outages, and then continue to use the remaining equipment.

This alternative is a temporary fix. One of the generators has a splice and is expected to fail in the next few years. If this generator fails before a new generator is ordered, this generator will be out of service for 2 years. The control system is a vintage system and is on the verge of a total failure and spare parts are not available (a few minor system failures occurred in the past 2 years). If a total system failure is encountered, it is expected the plant to be down for a year as the control system is designed, procured and installed.

Alternative 2: Replace all generating units with larger, vertical units capable of additional output. Avista's Power Supply group evaluated the present value of larger, vertical units at Little Falls. The increase in present value from larger units was $20M over a 30 year analysis. The capital construction cost increase from in-kind replacement to vertical units was $27M.

This present value calculation of benefit did not include risk. Installing new vertical units would require modification of the powerhouse foundation and presents serious construction risk. Due to the high construction costs, high risk, and low payoff NPV, this alternative was abandoned.

Alternative 3 and Proposed Alternative: Replace nearly all of the older and less reliable equipment with new equipment. This includes replacing two of the turbines, all four generators, all generator breakers, three of the four governors, all of the AVR's, removing all four generator exciters, replacing the unit controls, replacing the unit protection system, and replacing and modernizing the station service. All major equipment would be procured through a competitive bid process to help keep construction costs low. Equipment would also be purchased for all four units at once to help keep costs down.

Additional Justification for Proposed Alternative:

Because of the age and condition of all of the equipment at the plant, all of the equipment has been qualified as obsolete in accordance with the obsolescence criteria tool. The Asset Management tool has been applied to Little Falls and also supports this project. The Asset Management studies that have been done to date are still subject to further refinements, but the general conclusions support this project. There are many items in this 100 year old facility which do not meet modern design standards, codes, and expectations. This project will bring Little Falls to a place where it can be relied on for another 50 to 100 years. Finally, this project will need to be worked in coordination with our Indian Relations group as the Little Falls project is part of a settlement agreement with the Spokane Tribe.

Strategic Alignment:

The Little Falls Plant Upgrade aligns with the Safe and Reliable Infrastructure company strategy. The program will address safety and reliability issues while looking for innovative, economical ways to deliver the 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.

In accordance with the detailed project schedule, annual projected capital expenditures for remaining scope are in accordance with the 5-year CPG budget table below.

Year	Requested Amount	CPG Approved Amount *(Admin use only)*
2021	$800,000	
2022	$0	
2023	$0	
2024	$0	
2025	$0	

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

No direct relationship exists between the other parts of the business and the completion of the remaining Little Falls program work. All integral connection points with other business units have already been made. Equipment upgrades have been performed to support other corporate priorities (such as EIM and HMI) and plant processes that are impacted by the remaining work are directly and appropriately involved in the planning and scheduling of that work in order to insure seemless integration with the plant.

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

See alternatives analysis narrative conducted at project onset in section 2.1 for additional details. This project is in the closeout phase and budget is being adjusted into future years to respond to resource availability. Any remaining project risks will be mitigated at the project steering committee level for the remaining active program components.

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.

<u>Milestone Schedule (reflective of original business case milestones):</u>

January 2010 Program Begins

March 2012	Exciter & Generator Breaker Replacement Complete
January 2014	Warehouse Construction Complete
January 2014	Bridge Crane Overhaul Complete
February 2015	Station Service Replacement Complete
February 2016	Unit 3 Modernization Complete
April 2017	Unit 1 Modernization Complete
October 2017	Backup Generator Install Complete
May 2018	Unit 2 Modernization Complete
May 2019	Unit 4 Modernization Complete
October 2019	Headgate Replacement Complete

Yearly Transfer to Plant:

2013	$3,100,000
2014	$2,000,000
2015	$4,000,000
2016	$16,300,000
2017	$10,400,000
2018	$9,000,000
2019	$13,000,000
Total	$57,800,000

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

Mission: This project safely, responsibility and affordably improves the level of service we provide to our customers by minimizing our exposure to potential, prolonged breaks in service.

Strategic Initiatives: 1. Safe and Reliable Infastructure, 2. Responsible Resources.

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

Prudency considers not only the likelihood of risk but the severity of the outcome in the event of failure. Prior to their upgrade, failure of these sytems could have been nearly immediately catastrophic. Minimizing the severity of non-preventable failure is the prudent and responsible thing to do.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Customers and Stakeholders:

Mike Magruder	Manager, Hydro Operations and Maintenance
Alexis Alexander	Manager, Spokane River Hydro Operations
Kevin Powell	Chief Operator, Long Lake and Little Falls HED

3.1 Steering Committee or Advisory Group Information

This program is comprised of two layers of Steering Committee Oversight. One layer of oversight is at the program level and the other layer is at the project level.

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

The Program Steering Committee is responsible for vetting and approving the objective, scope and priority of the program. The deliverables for the program are then reviewed with the Program Steering Committee on a semi-annual basis. Any significant changes to the program's scope, budget or schedule will be approved by the Program Steering Committee. The Program Steering Committee is composed of the Director of GPSS and the Director of Power Supply. This committee meets semi-annually or as major events create a change order request.

The Project Steering Committee oversees the deliverables of the individual projects. Each member of the steering committee represents a major stakeholder in the project. The members are dependent on the respective project but will include representatives from hydro operations, central shops and engineering. The Project Steering Committee will approve any changes to the schedule, scope and budget of the individual project. They also are responsible for approving the necessary personnel for the completion of the project. This group is engaged on a quarterly basis.

More detailed project governance protocols will be established during the project chartering process whereby the Steering Committee will allocate appropriate resources to the management of all project activities, once better defined.

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

Project decisions will be made at the PM level where appropriate and escalated to the Project/Program Steering Committee when and if determined to be necessary by the definitions above. Regular updates will be provided to the Steering Committee by the PM team as project scope, schedule and budget are defined, and through the course of the project execution, change.

The undersigned acknowledge they have reviewed the HMI Control Software 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: Brian Vandenburg 0304BE8... Date: Jul-10-2020 | 8:14 AM PDT

Print Name: Brian Vandenburg

Title: Manager, Hydro Operations

Role: Business Case Owner

Signature: DocuSigned by: Andy Vickers 8E5EBAEEABB04AA Date: Jul-10-2020 | 8:30 AM PDT

Little Falls Plant Upgrade

Print Name: Andy Vickers
Title: Director of GPSS
Role: Business Case Sponsor

Signature: DocuSigned by: Scott Kinney 50D41B164A... Date: Jul-13-2020 | 5:56 AM PDT
Print Name: Scott Kinney
Title: Director of Power Supply
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Long Lake Plant Upgrade

EXECUTIVE SUMMARY

PROJECT NEED: The equipment needs to be upgraded for continued reliability as soon as possible. The existing equipment ranges in age from 20 to more than 100 years old. We have experienced an increase in forced outages at Long Lake over the past several years, almost zero in 2011 and increasing every year since then. This is caused by equipment failures on several different pieces of equipment. The other major driver for the program is safety. The switching procedure for moving station service from one generator to the other resulted in a lost time accident and a near miss in the past 5 years. In addition, the station service disconnects represent the greatest arc-flash potential in the company. This area is roped off and substantial safety equipment is required to operate the disconnects. This project will reconfigure this system to eliminate requiring personnel to perform this operation and avoid the arc-flash potential area.

RECOMMENDED SOLUTION: The recommended solution is Alternative 4, replace Units In-Kind. The Long Lake Plant Upgrade is a series of several capital project improvements built into a larger Capital Program.

The program includes a full plant condition assessment, replacement of all Generating Units, Generator Step-up Transformers (GSUs), Station Service, and many of the mechanical, electrical, and controls systems and equipment have met their end of useful life.

ALTERNATIVES CONSIDERED:
- Alternative 1: Install four new 60MW vertical units
- Alternative 2: Construct one unit powerhouse
- Alternative 3: Construct two-unit powerhouse
- Alternative 4: Do Nothing

COST OF RECOMMENDED SOLUTION: An anticipated program budget of $145M has been developed.

ADDITIONAL INFO: This equipment needs to be replaced in order to continue to operate efficiently. Upgrading our Long Lake Plant will enable our generation fleet to continue to provide safe and reliable power to our customers.

Long Lake serves Avista's allocated north electric district providing power to our transmission grid and local distribution power sources. The primary drivers for the Long Lake Plant Upgrade are Performance & Capacity, Asset Condition, and Failed Plant & Operations.

If not approved, The Long Lake powerhouse would continue to operate as it has for the past 10 years. O&M costs would continue to rise. Due to the condition of the generators, it is likely that one of the generators or another piece of major equipment will fail and permaM)nently disable equipment, increasing forced outage numbers. For example, in December of 2021 GSU 4 was replaced due to its dangerously high gas levels. This was a cost of $280k, and fortunately we had a spare otherwise the unit would still be out of service.

The Plant Upgrade began in 2017 and will continue until estimated completion in December 2029.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Steve Wenke	Initial Request	04/10/2017	This was on the old template
2.0	Mac Mikkelsen	Revised	09/02/2022	Transferred to new version
3.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
4.0	James Edwards/Mac Mikkelsen	Update for 2023 submission	05/10/2023	
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 19,800,000	$ 500K
2025	$ 17,500,000	$ 1.5 Million
2026	$ 16,700,000	$ 45 Million
2027	$ 16,500,000	$ 20 Million
2028	$ 15,900,000	$ 30 Million

Project Life Span	14 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

The existing equipment ranges in age from 20 to more than 100 years old. We have experienced an increase in forced outages at Long Lake over the past several years, almost zero in 2011 and increasing every year since then. This is caused by equipment failures on several different pieces of equipment. Specifically, the turbines are thrusting too much (a sign of significant wear), including a failure in 2015. The 1990 vintage control system is failing, and only secondary markets can support this equipment.

The original generators consist of a stator frame, stator core, stator winding, and rotor field poles. They were originally rated at 12 MW's. In the late 1940's, the height of the dam was raised 16 feet which resulted in more operating head for the generating units. A forced air-cooling system for the generators was added to the plant at that time to accommodate the increase in output from 12 to 17 MW's due to the increased head. In the 1960's, the stator windings on all the units were replaced and the rating of the generators, along with the forced air system allowed for the units to operate at the higher 17 MW output.

In the 1990's, the original turbine runners were replaced and upgraded. The improvement in turbine runner efficiency resulted in still another increase in unit output. Since the mid-1990's, the generators have been operating with a maximum output of 22 to 24 MW's. The generators are currently operated at their maximum temperature which stresses the life cycle of the already +50-year-old winding.

Inspections of other components of the generator show the stator core is "wavy". The core lamination steel should be in straight. The "wave" pattern is a strong indication of higher-than-expected losses occurring in the generator. Finally, maintenance reports have identified that the field poles on the rotor have shifted very slightly from their designed position over the years. While there can be several causes of this movement, it is speculated that it is due to the high operating temperatures of the generator. This highlights the first driver for the program, reliability.

With the increase in generator output, the output of the GSU has also increased to its rating. These GSU's are now running at the high 65° C temperature which is a concern. As these GSU's are more than 30 years old and operating at the high end of their design temperature, these are now approaching their end of useful life and need to be replaced proactively rather than waiting for a failure.

1.2 Discuss the major drivers of the business case

Asset Condition: Much of the plant and its components are aged to the point of failure and/or have become obsolete. The Long Lake HED is a critical asset needed for generation of clean renewable energy. The consistent and reliable operation of the generating units and related equipment is needed to be able to confirm generation, distribution, and transmission of electricity to our customers. The equipment is also essential to recreation, environmental protection, dam, and public safety. These all benefit the customer by increasing efficiency and safety in performance.

The other major driver for the program is safety. The switching procedure for moving station service from one generator to the other resulted in a lost time accident and a near miss in the past 5 years. In addition, the station service disconnects represent the greatest arc-flash potential in the company. This area is roped off and substantial safety equipment is required to operate the disconnects. This project will reconfigure this system to eliminate requiring personnel to perform this operation and avoid the arc-flash potential area.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The equipment needs to be upgraded for continued reliability as soon as possible. The risks of deferment may result in the lack of the ability to generate hydroelectricity and provide our commitment to the BES, and EIM. Deferment will also lead to increased O&M costs. The Long Lake powerhouse would continue to operate as it has for the past 10 years. O&M costs would continue to rise. In an additional 10 years, if the trend continues, average O&M costs will rise from $285k in 2005 to $590k in 2014 and projected to be $900k in 2024. Due to the condition of the generators, it is likely that one of the generators or another piece of major equipment will fail and permanently disable equipment, increasing forced outage numbers.

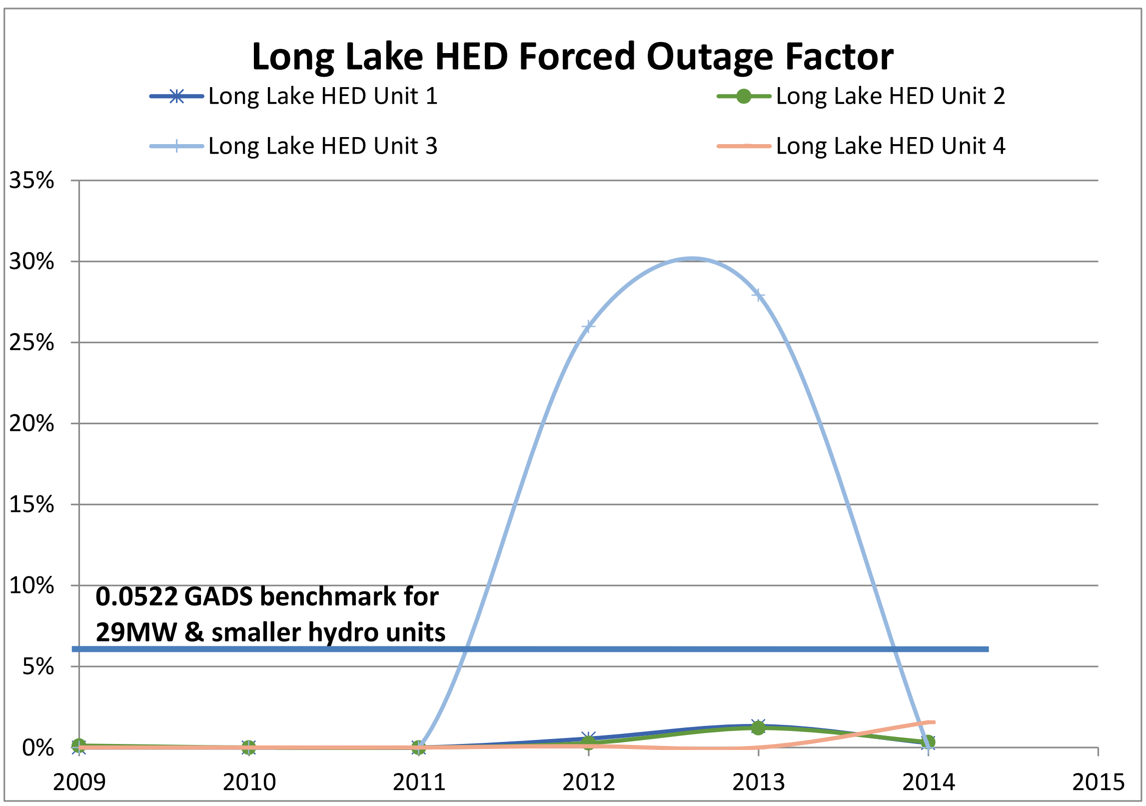
1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

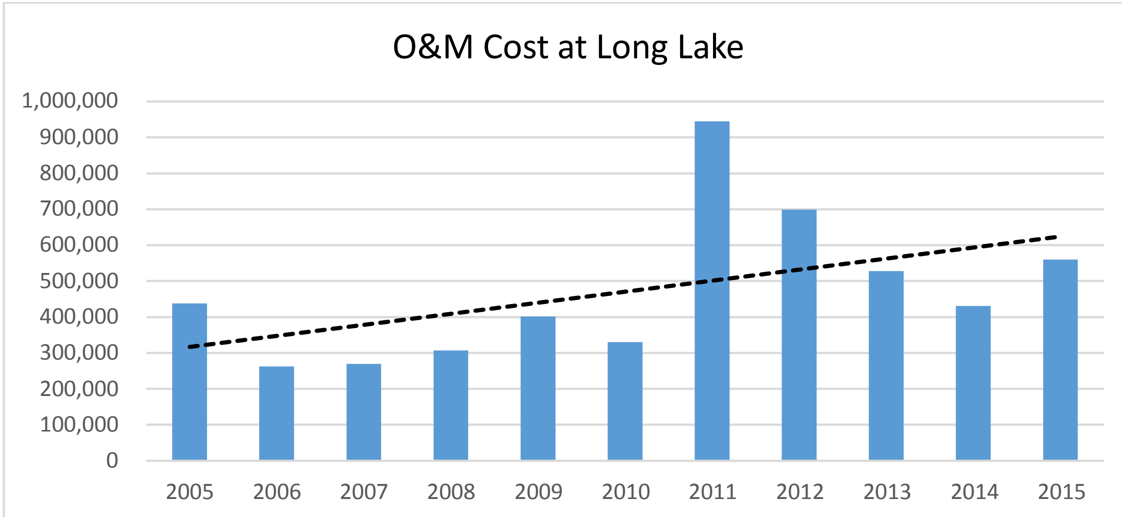
The Long Lake Plant Upgrade aligns with the Safe and Reliable Infrastructure company strategy. The program will address safety and reliability issues while looking for innovative, economical ways to deliver the projects.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

- Relevant data is comprised of Long Lake HED historical data, maintenance logs, asset condition, third party analysis, and lessons learned from similar work performed at Little Falls HED
- Summary of Investment Considerations for Long Lake Modernization Program
- Spokane River Assessment (Oct 2014) Phase II Reconnaissance Study – Long Lake HED – URS
- Long Lake Dam Generator Voltage Study & Life Cycle Analysis (June 2020) - Stantec
- Long Lake Modernization Basis of Design Index was developed to determine what systems and subsystems were in scope for the Modernization effort.
- Below is a graph of Forced Outage Factor for Long Lake HED from Avista's Asset Management Plan.



The below graph shows the O&M cost at Long Lake for years 2005 - 2015. The trendline is increasing due to increasing repairs to aging equipment.



[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: Replace Units In-Kind: replace the existing major unit equipment (generator, field poles, governors, exciters, generator breakers) with new equipment. The equipment needs to be upgraded for continued reliability as soon as possible. The risks of deferment may result in the lack of the ability to generate hydroelectricity and provide our commitment to the BES, and EIM. Deferment will also lead to increased O&M costs.

In Scope: Replace units (generator, field poles, governors, exciters, generator breakers) with new equipment. Disassembly and disposal of original equipment mentioned above. Demolition, Removal and Replace existing Station Service and GSUs. Location of current GSUs will be used for new exciter equipment. New GSUs will be placed on structural pads in the upper parking lot. A tailrace bulkhead has been designed and fabricated to mitigate high water levels during the unit replacement. Asbestos and lead abatement to allow for removal of existing East Mezzanine cubicles. Build new relay/communication room where East Mezzanine cubicles were located. New relay and communication equipment. Removal and disposal of existing emergency generator and purchase/installation of new EG outside of powerhouse. Design/build new battery room on breaker floor. Build new battery room on breaker floor. Purchase and install new battery bank and UPS. Completed work includes a sewer system overhaul, access road overhaul, bridge crane replacement, facilities upgrade (including new break and conference rooms), and a new forklift.

Out of Scope: This project will not include the design and installation of a substation outside of the powerhouse. Control Room will be upgraded but not moved. Parking lot improvements are being designed and implemented as part of Regulating Hydro and are not included in this effort. The roll up bulkhead door was completed in 2022 as part of Regulating Hydro. No work associated with the forebay, headgates, spillgates or crescent dam is included. Incline elevator assessment and replacement is not included. Assessment or refurbishment of penstocks is not included.

Assumptions:

Projects completed

- May 2017 – Project Kickoff
- September 2018 – Bridge Crane Replacement - Complete
- September 2018 – Sewer System Overhaul - Complete
- September 2018 – Access Road Overhaul - Complete
- January 2020 – Facilities Upgrades Phase 1 - Complete
- September 2021 – Tailrace Bulkhead - Complete

Projects planned execution to begin

- June 2024 – Man Door Bulkhead
- June 2024 – Plant Air System
- October 2024 - Station Service Replacement 1
- October 2024 – GSU Upgrade Phase 1
- October 2024 – First Unit Upgrade
- March 2025 – Battery Room / UPS
- November 2025 – Control Room Upgrade
- September 2026 – Second Unit Upgrade
- November 2027 - Station Service Replacement 2
- November 2027 – GSU Upgrade Phase 2
- November 2027 – Third Unit Upgrade
- November 2027 – Plant Sump System
- November 2028 – Fourth Unit Upgrade
- February 2026 – Facilities Upgrade Phase 2

Project #	Project	Start	Finish	LTD $
20305098	Station Service 2	03/2017	-	1,606,506
20305099	Bridge Crane Upgrade	04/2017	12/2019	2,354,027
20305105	Access Road Paving	01/2018	09/2018	1,128,036
20305106	Sewer System Upgrade	01/2018	01/2019	207,855
20305121	Unit 3 Modernization	02/2019	-	6,627,661
20305122	Unit 3 Upgrade (ET)	02/2019	-	36,950
20305123	Facilities Upgrade – Ph1	07/2019	01/2020	557,641
20305128	Facilities Upgrade (ET)	07/2019	06/2020	181,797
20305139	Tailrace Bulkhead (Unit Mod)	04/2020	03/2022	1,291,377
20305142	Forklift	10/2020	12/2020	124,752
02807019	6.9kV Substation	05/2022		123,752
20305177	GSU 4 Removal	03/2023		480
				$14,240,354

$5,845,485 has been transferred to plant through the completed projects above.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- Long Lake Dam Generator Voltage Study & Life Cycle Analysis (June 2020) - Stantec

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

- Long Lake Modernization Basis of Design Index was developed to determine what systems and subsystems were in scope for the Modernization effort.
- Class 5 Estimate from Stantec
- The 2018 Hydro Generation Condition & Risk Assessments is referred to as the "2018 Assessment. Early 2018 GPSS-Hydro department undertook an initiative to revamp their maintenance programs. This included the 2018 Assessment, which was conducted in the hydro plants and incorporated both Risk Assessments and Condition Assessments. Teams consisting of representatives from the Mechanic, PCM Tech, and Electric Shops, as well as Spokane River Hydro, Clark Fork River Hydro, and Maximo teams were formed and tasked with performing a condition and risk based assessment for assets in all of Avista's hydro facilities. Additional details may be found in the "2018 Hydro Asset Management Program Directory". The full reference is provided below:

  The Condition Assessments were based on the CEATI hydroAMP 2.0 guide. The database developed during the 2018 assessment has been used to create business information tools to identify and analyze equipment strategies to be used by GPSS for making business decisions.

  The purpose of the Risk Assessment was to identify the environmental, financial, and safety risks associated with each asset and what possible consequences might result from an asset failure. Consequences were framed within the Avista Business Risk Matrix. Financial risks might include lost generation during an outage. Probabilities were then estimated as an answer to the following question: Given an asset failure, what is the probability that a particular, potential consequence will actually occur? As an aid to this process, probabilities were selected from a menu of specified probability levels. Results of the Risk Assessments have been used to estimate asset risk costs. Risk cost is the product of the Failure Rate, Potential Consequence of failure. This risk cost is a probable dollar value associated with Avista's exposure risk of each asset.

  The results of the 2018 Assessment have been used to develop Asset Management Plans (AMPs) and a Risk Based Investment Planning (RBIP) tool. AMPs have been developed for a number of the asset classes, such as the generators, turbine runners, GSUs, trash rakes, etc. The AMPs outline capital and maintenance strategies. A primary purpose of the RBIP tool is to bring a risk-based perspective to the capital budget process.

  Reference - Avista Utilities, "2018 Hydro Asset Management Program Directory", Avista Utilities GPSS Dept., March 15, 2019

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028

Capital	Increase in production	$0	$50K	$100K	$150K	$200K
O&M	Reduction in labor and equipment for unplanned maintenance and breakdowns	$0	$50K	$100K	$150K	$225K

Over the past 11 years, the average O&M spend at Long Lake was $470k, with the low being $262k and the high year being $944k. In addition, the O&M cost is trending upward. After the upgrade, the expected O&M cost is $200k/year, an average reduction of $270k/year.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Reduction in forced outages that reduce generation	$0K	$250K	$750M	$1.25M	$1.75M
O&M	Less risk of outages leading to greater ability to plan employees work rather than reacting to breakdowns and failures	$100K	$150K	$200K	$250K	$300K

Indirect offsets are a result of fewer expected forced outages. This will lead to an increase in capital production, described above as a reduction missed capital. This is based on an assumption of $50k/day of generation per unit.

The O&M offsets are based on fewer outages leading to employees being able to remain allocated to current project and operation work. People are not reserved for outage work so when outages occur, they are pulled from their normally assigned tasks.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: The recommended solution is to replace Units In-Kind.

Alternative 1: Install four new 60MW vertical units; $173M

This alternative would be to replace the four existing units in the powerhouse with four new 30 MW Kaplan units. Significant civil, electrical, and mechanical work would be required, in addition to powerhouse access.

The increased yearly generation would be 114,000MWh. Using $30/MWh (extremely conservative number) the rough yearly benefit to Avista is $3.4M. The payoff period is greater than 30 years and therefore this alternative was abandoned.

Alternative 2: Construct one unit powerhouse; $144M

Instead of upgrading the current powerhouse, this alternative is to construct a new powerhouse with a single, 68MW next to the existing powerhouse, using the saddle dam (also referred to as the "arch dam") as an intake. This alternative would only use the old powerhouse during high flows, when flows exceeded the new unit's capacity. Additional funds would be required to upgrade, even at a minimum level, to address some of the failing components.

The increased yearly generation would be 170,000MWh. Again, using $30/MWh the rough yearly benefit to Avista is $5.1M. The payoff for this is 30 years. Again, since this cost does not include the additional work required in the plant and the cost of the risk associated with modifying the saddle dam, this alternative was abandoned.

Alternative 3: Construct two-unit powerhouse; $276M

Another option to build a new powerhouse is to construct a new powerhouse with two, 76MW units next to the existing powerhouse. This alternative would also use the saddle dam as an intake. This alternative would only use the old powerhouse during extreme high flows, minimizing the need to perform any upgrades to the old plant.

The increased yearly generation would be 258,000MWh. Using $30MWh, the rough yearly benefit to Avista is $7.7M. The payoff would be greater than 30 years and therefore the alternative was abandoned.

Alternative 4: Do Nothing; $0M

The Long Lake powerhouse would continue to operate as it has for the past 10 years. O&M costs would continue to rise. In an additional 10 years, if the trend continues, average O&M costs will rise from $285k in 2005 to $590 in 2014 and projected to be $900k in 2024. Due to the condition of the generators, it is likely that one of the generators or another piece of major equipment will fail and permanently disable equipment, increasing forced outage numbers.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The LLPU project team will be utilizing data from GPSS asset condition information, trending plant data, as well as third party engineering experts to assist in alternative analysis and engineering recommendations for upgrades. Third party studies have helped identify large scale options for the plant upgrade, and internal Avista engineering in partnership with third party consultants have added additional alternatives for consideration. Alternative analysis options are considering upfront costs, construction costs, life cycle costs, return of investment, and sustained maintenance costs, along with future capacity options.

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known

- **Start Date:** 2017
- **End Date:** 2031

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/Governance Team

This program is comprised of two layers of Steering Committee Oversight. One layer of oversight is at the program level and the other layer is at the project level.

The Program Steering Committee is responsible for vetting and approving the objective, scope, and priority of the program. The deliverables for the program are then reviewed with the Program Steering Committee on a semi-annual basis. Any significant changes to the program's scope, budget or schedule will be approved by the Program Steering Committee. The Program Steering Committee is composed of the Director of GPSS, Director of Environmental Affairs, and the Director of Power Supply. This committee meets semi-annually, or as major events create a change order request.

The Project Steering Committee oversees the deliverables of the individual projects. Each member of the steering committee represents a major stakeholder in the project. The members are dependent on the respective project but will include representatives from hydro operations, central shops, and engineering. The Project Steering Committee will approve and changes to the schedule, scope, and budget of the individual project. They also are responsible for approving the necessary personnel for the completion of the project. This group is engaged on a quarterly basis.

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Long Lake Plant Upgrade business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 11:08 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alexis Alexander EA27BABA767F467...	Date:	Aug-26-2023 | 1:31 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		
Signature:	NA	Date:	
Print Name:	NA; Alexis Alexander is currently on the project Advisory Committee		
Title:	NA		
Role:	Steering/Advisory Committee Review		

Monroe St Abandoned Penstock Stabilization

EXECUTIVE SUMMARY

The Monroe Street Powerhouse was initially constructed in 1890 and has undergone several modernizations over the last 129 years. During the 1972 modernization, three of the original penstock intakes were plugged with concrete and sealed with a layer of shot-crete. The three 10 ft. diameter steel penstocks were only partially removed, leaving an approximate 250 ft. length of each buried under what is now Huntington Park. It is unknown if the penstocks were also backfilled with material, posing a risk of implosion. These penstocks run underneath parts of the access road, crane staging area, and walking path through the park. The park is open to the public, and the access road and crane areas are critical to maintaining the safe and efficient operation of the Monroe Street Hydroelectric Development. During the 2018 Maintenance Assessment, these penstocks were identified as a high risk due to their location, unknown condition, and observed groundwater.

The recommended solution includes further investigation of the intake dam and penstocks to better quantify the risk, and implementation a plan to mitigate those risks. The scope of this work would likely include an initial engineering evaluation, including investigatory drilling, with stabilization efforts likely to include grouting of the intake and penstock.

The estimated cost of the project is $900,000. The service code for this program is Electric Direct and the jurisdiction for the project is Allocated North serving our electric customers in Washington and Idaho. Operating Monroe Street safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ryan Bean	Initial draft of original business case	6/21/2019	
1.0	Ryan Bean	Updated Approval Status	7/2/2019	Full amount approved
2.0	Ryan Bean	5 Year Planning 2020 & New Form	7/8/2020	

Monroe St Abandoned Penstock Stabilization

GENERAL INFORMATION

Requested Spend Amount	$900,000
Requested Spend Time Period	2 years
Requesting Organization/Department	C07/GPSS
Business Case Owner | Sponsor	Ryan Bean | Andy Vickers
Sponsor Organization/Department	C07/GPSS
Phase	Initiation
Category	Project
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

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

The Monroe Street Powerhouse was initially constructed in 1890 and has undergone several modernizations over the last 129 years. During the 1972 modernization, a new turbine intake and penstock arrangement was installed, just prior to Expo ’74. During this upgrade, three of the original penstock intakes were plugged with concrete and sealed with a layer of shot-crete. The three 10 ft. diameter steel penstocks were only partially removed, leaving an approximate 250 ft. length of each buried on site. It is unknown if the penstocks were backfilled with material, posing a risk of implosion. The penstocks are located under what is now Huntington Park and run underneath parts of the access road, crane staging area, and walking path through the park.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer.

The driver for this business case is Failed Plant. The original penstocks are no longer functional and pose a risk to the continued operation of the park and the power plant. Monroe Street supplies year-round base load hydroelectric power to Avista’s portfolio. Continuing to operate Monroe Street safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

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

The penstocks are located under what is now Huntington Park and run underneath parts of the access road, crane staging area, and walking path through the park. The park is open to the public, and the access road and crane areas are critical to maintaining the safe and efficient operation of the Monroe Street Hydroelectric Development. During the 2018 Maintenance Assessment, these penstocks were identified as a high risk due to their location, unknown condition, and observed groundwater. Due to the unknown condition of these penstocks, there is a risk of implosion of the abandoned penstocks due to deterioration, potentially resulting in an uncontrolled release of water thereby jeopardizing the plant and the park.

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 investment would field effort in two phases. The first phase would consist of an investigation of the penstocks and original intake dam to determine the condition. The second phase would implement corrective actions to eliminate the risk from implosion and ensure the intake structure is watertight and fit for continued service. The measure of success would be the stabilization of the above components resulting in the mitigation of risk to the public and continued production at the plant.

1.5 Supplemental Information

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

See project documentation from 2016 storm water controls and investigation.

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 metric supporting the stabilization of the current system is that it is no longer useful and poses a risk to continued operation of the park and plant. During the 2018 Maintenance Assessment, these penstocks were identified as a high risk due to their location, unknown condition, and observed groundwater.

3	Asset Group	Condition Rating	U1
59	Abandoned Penstocks	Poor	0.00
64	Dam Concrete - Original Intake / Penstock Plugs	Poor	1.2
	Dam Concrete - Seawall / Retaining Wall	Poor	1.2

Option	Capital Cost	Start	Complete
Investigate to ascertain condition; and mitigate leakage or instability if needed.	$900,000	01 2021	12 2022
Continue to operate at risk.	$0	01 2021	

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

The failure of the system and risk to the plant is the primary metric for justification of the project. A significant increase in ground water was observed in Huntington Park in 2007 when groundwater was observed to be traveling through the 13.8 kV underground electric vault and into the powerhouse, requiring remediation at the electric vault. Since 2007, excessive groundwater persisted to leak into the powerhouse through cracks in the concrete, and underground conduit penetrations, requiring constant monitoring and controls to be installed to manage the water. In 2015 excessive groundwater was observed to be flooding portions of Huntington Park, requiring areas of the park to be restricted for use. The flooding in Huntington Park increased by a magnitude again in 2016, requiring additional storm water controls and investigation into the source which was determined to be strongly associated with the buried penstocks, validating the drawings indicating the presence of the buried penstocks and associated infrastructure.

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 cost will be spread out over two years. The first year will be primarily engineering, investigatory drilling, and determination of needed remediation. This is estimated to be $150,000. The second year will include contractor mobilization and execution of the remediation plan. This is estimated to be $750,000. This will not offset significant O&M charges because the equipment is no longer in service so it is no longer maintained.

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

The execution of this project will temporarily inhibit access to the park and power plant due to investigatory and remediation efforts. The outcome of this project will also answer questions about loading of the access road that would impact future rehabs of the plant.

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

Continue to Operate at risk.: The level of risk is unknown due to the condition of the penstocks being unknown. However, the risk is likely to increase over time due to deterioration of the penstocks and the presence of groundwater in the park. Given the risk to the public, plant operations, and the company's reputation; doing nothing is not advisable.

Investigate and Remediate: This alternative includes further investigation of the intake dam and penstocks to better quantify the risk, and implementation a plan to mitigate those risks. The approach to fix is likely to involve grouting for penstock and intake stabilization, as well as measures for additional water management and monitoring. This alternative would provide a lasting solution to the above concerns and prevent future issues with access and safety.

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 project is expected to take two years. The effort in the first year will be devoted investigation and design. The effort in the second year will consist of execution of a remediation plan. The transfer to plant will be at the end of the second year with the completion of the work.

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

Operating Monroe Street safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES). By taking care of this plant we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Monroe Street will continue to provide reliable service and mitigate risk to the park and Avista's reputation.

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 impacts due to an implosion could harm Avista employees, the public, continued generation from the powerhouse, and Avista's reputation.

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

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are, the Hydro Regional Manager on the Upper Spokane, the Upper Spokane plant personnel, GPSS Engineering, Environmental Resources, the City of Spokane and Parks. Other stakeholders may be identified during project initiation**.**

2.8.2 Identify any related Business Cases

This project will need to be completed prior to any substantial rehab at the Monroe Street power plant, however this is not anticipated to be needed for some time.

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

Monroe St Abandoned Penstock Stabilization

The undersigned acknowledge they have reviewed the Cabinet Gorge HVAC 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 Bean	Date:	7/30/20
Print Name:	Ryan Bean		
Title:	Plant Manager, Upper Spokane		
Role:	Business Case Owner		

Signature:	ANdrew Vickers	Date:	7/31/2020
Print Name:	Andrew Vickers		
Title:	Director GPSS		
Role:	Business Case Sponsor		

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

Template Version: 05/28/2020

2022-2023 CAPITAL PROJECT
SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name: Monroe St Abandoned Penstock Stabilization

2. Business Case Owner: Ryan Bean

3. Director Responsible: Andy Vickers

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

There will be no Direct Savings resulting from this Business Case. This equipment has reached the end of its useful life and needs replaced to ensure that Monroe Street Dam continues to provide safe, reliable, and affordable energy to Avista's customers.

Quantified direct savings:

2022	2023	Lifetime
0	0	0

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Asset analysis of this project results in the "Risk Cost Reduction" shown below, reflective of the premium that would be paid if we were to insure against asset failure during this time frame. This calculated indirect savings considers the condition of the asset, the probability of failure, the probable consequence of failure and other risk factors such as personnel and public safety, environmental impacts, and unplanned outages and repairs.

Quantified indirect savings:

2022	2023	Lifetime
$308,766	$320,380	$923,827

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

Though there are no Direct Savings, there are Indirect Savings for this Business Case. By completing this work, we will ensure Monroe Street Dam continues to provide safe, reliable, and affordable energy to Avista's customers.

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

Director Name ________Andy Vickers_______________________________________

Director Signature _____ _____________________________________

Date _____________________10/26/2021_________________________________

Nine Mile Powerhouse Roof Replacement

EXECUTIVE SUMMARY

The Nine Mile Falls generation plant is over 100 years old. The roof trusses and concrete slab is original construction, and the roofing membrane was possibly updated in 1984 - 38 years ago or more with temporary patches and repairs since. Many inspections conducted over the years have determined that the roof is leaking and deteriorating, and the most recent June 2021 inspection by Garland Roofing stated that “overall the roof system has come to the end of its serviceable life” and is badly in need of complete replacement. As the engineering team has investigated the roof’s condition, more information has come to light revealing that the roof’s steel truss members in their current state are overstressed supporting the roof system weight (concrete roof slab and roofing membrane material) alone with no extra capacity for live loads, such as snow. Additional concerns include the condition of the 100-year-old steel trusses, which have experienced some damage and corrosion over the years and still has the same 100-year-old coating system.

The recommended solution is to address the overstressed condition of the steel trusses and to replace the failed roof membrane system. The supporting steel truss members will either be upgraded to increase their structural capacity or the concrete roof slab panels be replaced with lighter weight roofing material to reduce load on the steel trusses.

The estimated cost for the roof is $1,000,000 to address both the structural and roofing needs. The service code for this program is Electric Direct and the jurisdiction for the project is Allocated North serving our electric customers in Washington and Idaho. Operating Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ryan Bean	Initial draft of original business case	8/18/2022	

GENERAL INFORMATION

Nine Mile Powerhouse Roof Replacement

Requested Spend Amount	$ 1,000,000
Requested Spend Time Period	1 Year
Requesting Organization/Department	C07/GPSS
Business Case Owner | Sponsor	Ryan Bean | Alexis Alexander
Sponsor Organization/Department	C07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The powerhouse roof at Nine Mile needs replacement due to age and deterioration. The current membrane leaks and the existing roof trusses are in an overstressed condition that requires remediation.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

The driver for this business case is Asset Condition. The powerhouse roof is needed in good condition to protect the inner workings of the generating plant. Nine Mile supplies year-round base load hydroelectric power to Avista's portfolio. Continuing to operate Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

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

The roof has reached the end of its serviceable life and is structurally deficient. If not addressed in the near future, the condition of the roof will continue to degrade, exposing the plant to water infiltration and potential failure due to its overstressed condition.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The measure would include restoring the structural integrity and watertight seal of the roof to provide years of service to come. By restoring the roof, we protect our ability to generate low-cost power for our customers.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

- NM Roof Structure Analysis Memo
- Roof Truss Steel Coupon Test Results

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

Per roofing condition inspection, the roof has reached the end of its useful life.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
1. Address overstress and membrane condition	$1,000,000	01 2023	12 2023

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

The failure of the existing roofing membrane is the primary metric for justification of the project. Investigative measures have been taken to determine the exact quality of the roof and its components. These measures include steel and concrete assessments and analysis. By addressing the problem, we mitigate the risk of water damaging critical generating equipment and/or roof failure.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e., what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M because of this investment.

The capital costs will be spread over 1 year. Current investigative efforts will inform selection of an appropriate structural remedy and those costs will be transferred to this project. Truss remediation will precede the roof membrane replacement in the fall. This will not offset significant O&M charges because roofing and roof trusses are low maintenance items.

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

The execution of this project will enable the continued operation of Nine Mile Units HED. Plant production and reliability will be impacted without a sound roof.

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

OPTION 1: Upgrade the 8 steel trusses by reinforcing the overstressed members to provide greater capacity.

Pro’s:

- Regardless of what option is chosen, the roof trusses need to be maintained by sand blasting and painting
- Reinforcing truss members improves strength/capacity of truss for dead load and live load

Con’s:

- Unloading the truss is tricky and could put a member designed for tension into compression; applied forces/stresses need monitored
- Lead abatement required (steel truss clean up and painting)

OPTION 2: Reduce the dead load weight on steel trusses by cutting out concrete sections of the roof and replacing with metal lightweight deck material.

Pro’s:

- Regardless of what option is chosen, the roof trusses need to be maintained by sand blasting and painting
- Cutting out concrete sections reduces dead weight on truss members

Con’s:

- Uneven areas where cutouts made?? Or can these areas be built up and then a new membrane applied and not have compromising uneven roof areas that create issues in the future?
- Dusty & concrete fines need contained (in powerhouse) during concrete cutting
- Lead abatement required (steel truss clean up and painting)

OPTION 3: Perform complete tear off the concrete roof and concrete beams over the trusses (unless it makes more sense to keep the concrete beams and just remove the slab) and replace with a new roof (metal deck & membrane roofing).

Pro’s:

- Regardless of what option is chosen, the roof trusses need to be maintained by sand blasting and painting

- Reduces dead weight on truss members; new roof material would be much lighter than existing concrete roof

Con's:

- Extensive work and could be disruptive to plant operations
- Lead abatement required (steel truss clean up and painting)

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

Costs will be transferred to plant as the stages of work are completed. First will be the truss remediation followed by the new roofing membrane.

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

Operating Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES). By taking care of this plant, we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Nine Mile will continue to provide reliable service and mitigate risk to future projects and fielding unplanned failures.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Nine Mile HED is Avista's fifth largest hydroelectric plant. Roof projects of his size and complexity fall into this range of costs.

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

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are, the Hydro Regional Manager on the Upper Spokane, the Upper Spokane plant personnel, GPSS Engineering, GPSS Construction and Maintenance, and Power Supply. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

This project will need to be sequenced with several other projects that are in process including crane overhauls and Unit 3 & 4 overhauls.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed using project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Nine Mile Powerhouse Roof Replacement project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Nine Mile Powerhouse Roof Replacement

Signature:	Ryan Bean Digitally signed by Ryan Bean Date: 2022.08.31 11:04:24 -07'00'	Date:	
Print Name:	Ryan Bean		
Title:	Plant Manager		
Role:	Business Case Owner		

Signature:	Alexis Alexander Digitally signed by Alexis Alexander Date: 2022.09.02 16:13:32 -07'00'	Date:	
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

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

Nine Mile Unit 3 Mechanical Overhaul

EXECUTIVE SUMMARY

PROJECT NEED: There are a multitude of mechanical issues with Nine Mile Unit 3. The original Unit 3 was replaced with a new American Hydro unit in 1995. Unit 3 experienced cracked buckets on the runners in 2010. This was found to be due to heavy wear due to erosion from sediment and cavitation damage. The cracks were repaired; however, the sediment wear has continued, and bucket failure is anticipated. The installed roller guide bearing also does not provide the thrust bearing support it was designed to, causing the upstream generator guide bearing to take the entire thrust loading of the machine. This condition puts increased stress and wear on the generator bearings and increases the risk of failure. During the 2018 Maintenance Assessment, this bearing was identified as high risk due to its current condition.

RECOMMENDED SOLUTION: The recommended solution is to mechanical overhaul the Unit including installing new Francis Runners, new downstream water lubricated bearing and pedestal, new combination thrust/guide bearing with thrust shaft, and refurbishment of the wicket gate stems and all operating components

ALTERNATIVES CONSIDERED:
- Alternative 1: Do-nothing and continue to repair the current system under O&M.

COST OF RECOMMENDED SOLUTION: The estimated cost of the project is $6,500,000

ADDITIONAL INFO: Operating Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES). This alternative would provide a lasting solution to the problems outlined above and avoid a costly unanticipated failure. If left unaddressed, the Unit is likely to experience bucket or bearing failure.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ryan Bean	Initial draft of original business case	6/21/2019	
1.0	Ryan Bean	Updated Approval Status	7/2/2019	Full amount approved
2.0	Ryan Bean	5 Year Planning 2020 & New Form	7/8/2020	
3.0	Ryan Bean	5 Year Planning 2021	7/2/2021	
4.0	Ryan Bean	Annual Update	7/29/2022	No Changes
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 2,007,261	$ 5,346,757
2025	$ 0	$ 0
2026	$ 0	$ 0
2027	$ 0	$ 0
2028	$ 0	$ 0

Project Life Span	3 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

The runners, as well as other critical mechanical components, including buckets, are not performing and are approaching end of life.

1.2 Discuss the major drivers of the business case

The driver for this business case is Asset Condition. Several critical components of the unit are at or approaching end of life. Nine Mile supplies year-round base load hydroelectric power to Avista's portfolio.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

If the condition of this Unit is left unaddressed, the Unit is likely to experience bucket or bearing failure resulting in extended down time and lost generation. In the event of an unanticipated failure, procuring new replacement runners would likely take at least 8-12 months to procure, resulting in substantial loss of power generation.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. Avista Strategic Goals

Continuing to operate Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The metric supporting the overhaul of the current system is that it is at or approaching end of life. In addition to worn runners, the installed F.A.G. roller guide bearing also does not provide the thrust bearing support it was designed to, causing the upstream generator guide bearing to take the entire thrust loading of the machine. The bearing supports the full thrust loading on a small thrust collar that was not designed for it, resulting in additional wear and heating. This condition puts increased stress and wear on the generator bearings and increases the risk of failure.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

During the 2018 Maintenance Assessment, this bearing was identified as high risk due to its current condition. The table below is an excerpt from the 2018 Maintenance Assessment. The condition indicators are dimensionless scores. A 3 is rating of good. On the bottom end, a 0 is poor. 2 and 1 are fair and marginal, respectively.

1	**Net Condition Index & Rating Summary**		
2			**Units**
3	Nine Mile Falls HED Asset Group	Condition Rating	U1
29	Turbine Bearings, Unit 3 Oil Lube	Poor	1.333

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: The recommended solution is to mechanical overhaul the Unit including installing new Francis Runners, new downstream water lubricated bearing and pedestal, new combination thrust/guide bearing with thrust shaft, and refurbishment of the wicket gate stems and all operating components. If the condition of this Unit is left unaddressed, the Unit is likely to experience bucket or bearing failure resulting in extended down time and lost generation. In the event of an unanticipated failure, procuring new replacement runners would likely take at least 8-12 months to procure, resulting in substantial loss of power generation. This solution replaces the mechanical components that are near failure/at end-of-life.

In Scope: In kind replacement of Francis Runners (4), new downstream water lubricated bearing and pedestal, new combination thrust/guide bearing with thrust shaft, and refurbishment of the wicket gate stems (2 stems on each wicket gate, 64 wicket gates total) and all operating components (including shift ring, operating rods, and mechanical linkages (shafts and bearings)); cooling water work (?)

Out of Scope: Work will not be replacing any primary shafts; design work; cooling water work

Assumptions: New equipment will be purchased new, AVA crafts will be installing, Servos will be replaced under a different project, no crane work will be required; primarily Avista labor; adding bearing to system; full set of bearing pads; major components to be refurbished will be sent out for contract refurbishment. No design work, scope is equivalent to work completed on Unit 4 (2014)

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- See 2010 Unit 3 Bucket Repair documentation and Unit 4 Mechanical Overhaul Project documentation.
- CARS (Capital Additions and Retirement) form which documents added and removed assets associated with Avista's facilities. This document helps Avista maintain accurate continuing property records.

- In early 2018, the GPSS-Hydro department undertook an initiative to revamp their maintenance programs. This initiative included an overall assessment of all hydro plants in Avista's fleet. The program included both Risk Assessments and Condition Assessments. The 2018 Hydro Generation Condition & Risk Assessments, is referred to as the "2018 Assessment." Teams consisting of representatives from the Mechanic, PCM Tech, and Electric Shops, as well as Spokane River Hydro, Clark Fork River Hydro, and Maximo teams were formed and tasked with performing a condition and risk-based assessment for assets in all Avista's hydro facilities. Additional details may be found in the "2018 Hydro Asset Management Program Directory". The full reference is provided below:

  The Condition Assessments were based on the CEATI hydroAMP 2.0 guide. The database developed during the 2018 assessment has been used to create business information tools to identify and analyze equipment strategies to be used by GPSS for making business decisions.

  The purpose of the Risk Assessment was to identify the environmental, financial, and safety risks associated with each asset and what possible consequences might result from an asset failure. Consequences were framed within the Avista Business Risk Matrix. Financial risks might include lost generation during an outage. Probabilities were then estimated as an answer to the following question: Given an asset failure, what is the probability that a particular consequence will materialize? As an aid to this process, probabilities were selected from a menu of specified probability levels. Results of the Risk Assessments have been used to estimate asset risk costs. Risk cost is the product of the Failure Rate, Potential Consequence of failure. This risk cost is a probable dollar value associated with Avista's exposure risk of each asset.

  The results of the 2018 Assessment have been used to develop Asset Management Plans (AMPs) and a Risk Based Investment Planning (RBIP) tool. AMPs have been developed for a number of asset classes, such as the generators, turbine runners, GSUs, trash rakes, etc. The AMPs outline capital and maintenance strategies. A primary purpose of the RBIP tool is to bring a risk-based perspective to the capital budget process.

  Reference - Avista Utilities, "2018 Hydro Asset Management Program Directory", Avista Utilities GPSS Dept., March 15, 2019

- Risk Cost calculation from GPSS Asset Management Group: Risk cost is the product of the Failure Rate, Potential Consequence of failure, and the Probability of experiencing the potential consequence in the event of a failure. This risk cost is associated with the probable dollar value associated

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

with Avista's exposure risk of each component. This exposure risk includes the cost of anything that threatens the company, including costs associated with a probable failure of the components (potentially including replacement, refurbishment, or lost generation costs), safety risks associated with normal operation or replacement actions, and probable environmental risks associated with the asset, and at times other costs such as public perception risk mitigation activities. While the company may not be able to shelter itself from risk completely, there are ways it can help protect itself from the effects of business risk, primarily by adopting a risk management strategy as a part of the asset management program. Risk costs not only take account for the exposure risk for an asset but also the criticality (or importance of an asset) and its' current condition. Risk costs are somewhat analogous to insurance premiums. They represent an annual cost, but the year-to-year costs vary with the condition of the assets. If we total the risk costs for all of our assets for the next year, the company would need to have monies set aside for that year to cover the costs associated with the assets that fail that year.

$$\begin{aligned}&Annual\ Risk\ Cost\\&= [Probability\ of\ Failure\ (that\ year)] \times [Consequence\ \$]\\&\times [Likelihood\ of\ actually\ experiencing\ that\ consequence]\end{aligned}$$

- A similarly scoped project was performed on Nine Mile Unit 4 several years ago. Project cost estimates and construction experience from the project were used to estimate a nearly identical body of work for Unit 3.

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Reduced Outages	$0	$0	$0	$0	$0
O&M	Reduced Maintenance	$50,000	$0	$0	$0	$0

This project will offset annual O&M maintenance charges in responding to failed components and mitigate the risk of unanticipated failures.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

Estimated indirect savings and/or productivity gains and associated benefits have not been quantified at this time; however, as applicable, please see the referenced Risk Based Investment report (see Section 2.2) for additional information.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: The recommended solution is to mechanical overhaul the Unit including installing new Francis Runners, new downstream water lubricated bearing and pedestal, new combination thrust/guide bearing with thrust shaft, and refurbishment of the wicket gate stems and all operating components. The investment would be fielded in several phases over the course of two years. The design, procurement, and installation specifications of the new equipment would be overseen by GPSS Engineering as part of a project team.

Alternative 1: Continue to Repair Current System; Capital Cost ($0)

This alternative would not replace or rehabilitate any mechanical components. Labor and materials would be used to fix equipment as needed. While the Unit is capable of continued operation in its current state, the likelihood of catastrophic failure due to runner or bearing failure is increasing. Due to the engineering required and long lead times on this equipment, the financial impacts of a failure would be substantial due to extended down time. Given the current bearing condition and known wear on the runners, doing nothing is not a preferred option.

2.6 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known

- **Start Date:** 2022
- **End Date:** 2024

☐Timeline is Unknown

2.7 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/Governance Team

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Nine Mile Unit 3 Mechanical Overhaul and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 11:04 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alexis Alexander EA27BABA767F467...	Date:	Aug-26-2023 | 1:38 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

Signature:	NA	Date:	
Print Name:	NA; Michael Truex is currently on the steering committee		
Title:			
Role:	Steering/Advisory Committee Review		

Noxon Rapids Spillgate Refurbishment

EXECUTIVE SUMMARY

The eight Spillgates at Noxon Rapids HED are over 60 years old and are the original gates. The Spillgates are critical equipment which control the flow of water over the dam during spill conditions when the water flowing in the river exceeds that which passes through the turbines in the plant. They are also protection for the dam during high flow periods or in the event that the plant or units trip to prevent overtopping or flooding of the dam. The gates require repair or replacement due to age, future EIM usage requriements, and structural analysis which reveals that the current gates may not be designed to meet the loading requirements during operation and due to seismic conditions. The spillgate issues must be resolved in the near future for the safety and reliability of the plant personnel and equipment. Fully functioning spillgates is a FERC requirement and part of the Dam Safety program. At the time of writing this document, the FERC was reviewing a site specific seismic hazard assement performed at Noxon Rapids, the results of which will inform the project on the necessary path forward, whether the gates are refurbished or if they are required to be replaced.

The path forward and recommended alternative has taken different forms over the life of this project. It started out as potential refurbishment or replacement of the gates, however, has morphed into a refurbishment project to strengthen specific identified weaker members of the gate to meet necessary FERC and design standards to meet all operating conditions – besides seismic. The FERC is continuing to review the seismic hazard assessment at Noxon Rapids, which will inform the necessary seismicity requirements at the facility. However, a potential outcome of that assessment would be more significant enhancements necessary across the entirety of the plant, and as such, the determination to proceed with the strengthening project at this time was prudent to ensure that the spillgates meet all normal operating requirements. The project budget originally was estimated at $24.9M, where the revised request is down to $3.85M with the revised scope of work. The recommended solution was reviewed by GPSS Engineering and approved by GPSS Management and the project steering committee.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*PJ Henscheid*	*Format existing BC into exec summary*	*7.6.20*	*5-year Capital Planning Process*
2.0	*Jessica Bean / PJ Henscheid*	*Completion of full BCJN document*	*8.3.20*	*5-year Capital Planning Process*
3.0	*PJ Henscheid*	*Updated to 2022 template and modified budget to align with improved estimates*	*8.24.22*	

GENERAL INFORMATION

Requested Spend Amount	$3,850,000
Requested Spend Time Period	*6 years, 2019 - 2024*
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	PJ Henscheid | Alexis Alexander
Sponsor Organization/Department	GPSS
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]

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

(1) The Noxon Spillgates are nearing the end of their useful life as Avista transitions into the EIM market. EIM will require the spillgates to be used at greater frequencies than they are today and with finer movements. The gate mechanisms can't support these types of and quanity of movements due to age, material, and design. (2) The gates are structurally insufficient when compared against the FERC requrements for structural stability when an earthquake hits. If an earthquake hits and damages the dam such that they are unoperable, that could potentially be a danger to plant personnel, the community downstream, and Avista's ability to generalte electricity in a prudent 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

(1) MANDATORY & COMPLIANCE Working and safe tainter gates are required by FERC. Additional scrutiny is placed on tainter gates by FERC after the Folsom Dam Failure. If Avista neglects to address the conditons that FERC has put into place and expects from this project, in particular, we will be out of regulatory compliance. (2) PERFORMANCE & CAPACITY fully functioning spillgates are an integral part of a fully functioning dam. They maintain the forebay level which, in turn, helps dictate the amount of power generated for our customers; they keep customers safe by controlling the amount of water that flows downstream during normal operations and during flood events (3) ASSET CONDITION The gates are original to the dam. The Noxon Spillgates are nearing the end of their useful life as Avista transitions into the EIM market. EIM will require the spillgates to be used at greater frequencies than they are today and with finer movements. The gate mechanisms can't support these types of and quanity of movements due to age, material, and design. This affects our customers because Avista may not be able to provide power at the needed rate or quantity.

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

See Section 1.1. Additionally, Avista has communicated to FERC that a gate project is forthcoming. Should we neglect to move forward with this project, Avista would be out of regulatory compliance.

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) constructing a FERC approved design would remove Avista from any regulatory compliance lists that we are on due to insufficiently strong spillgates; (2) The gates would operate such that the plant operators could support the directives from the EIM market.

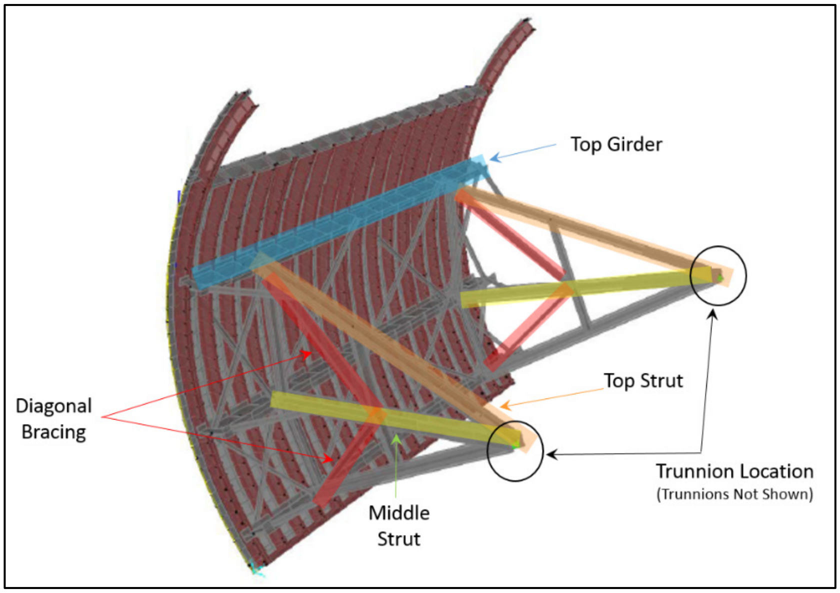
1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

- GPSS "G" Drive @ \\c01m114
  - G:\Generation\401 Noxon Rapids\Projects\ER-4187 Spillgate Refurbishment\40105196 Spillgate Remediation\05 Engr\05.12 -Studies and Inspections
    - LCI Seismic Analysis: *this document discusses the seismicity of the Noxon, Montana*
    - Strata Shear Wave Velocity Testing*: this document provides data showing how seismic waves move through the ground at Noxon*
    - Stantec Structural Report*: this document takes the seismic data and the seismic analysis, applies it to the dam using models, and discusses the failure points of the facility*
    - Schnable Seismic Hazard and Geophyiscal Report: *This is Avista's Part 12 Inspector review of the LCI Seismic Analysis*
  - G:\Generation\' Hydro Plants\Noxon Rapids HED\Projects\2020 Spillgate Rehab\09 Submittals
    - Draft Structural Report*: this document updates the Stantec Structural Report noted above using LCI Sesimic Analysis data*
    - Drafit Pier Analysis Technical Memo*: this document summarizes the structural analysis of the Noxon Dam spillway piers to accommodate a cross-valley seismic event*
    - Draft Electrical Systems Evaluation Report*: this document reviews the feasibility of reusing the existing electrical infrastructure*
    - Draft Gate Trunnion System Review*: this document evaluates the past use of the gates, future use of the gates, and the existing conditions to help arrive at a recommendation for their replacement.*
    - Draft Gate Hoist System Review*: this document reviews the existing hoist condition, expected lifting capacity, and potential for upgrade and modernization*

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.

At minimum, the highlighted members require strengthening. Depending on the size of an earthquake the FERC will require the gates to withstand, the entire gate could be replaced as well as the associated mechanical and electrical gear. If the earthquake required by the FERC is large enough, it may require modifying the concrete Spillgate piers. At this time however, the members will be only strengthened.



2. PROPOSAL AND RECOMMENDED SOLUTION

Continue on with the project. This is the best solution because we have promised the FERC that we will mitigate structural issues on the spillgates and it will ensure the spillgates have a long life once we have entered the EIM market.

Continuing forward with the proposed strengthening project of the identified weak members provides confidence and our ability to meet all FERC design requirements for Tainter gates until such time as we realize the full impacts of the seismicity at site.

Option	Capital Cost	Start	Complete
Recommended: Strengthen the diagonal members with bracing until such time as seismicity can determine the best path forward for the gates	*$3,850,000*	*01/2019*	*12/2024*
Alternative 1: Rehab/Replace the Noxon Spillgates following determination of seismicity needs	*$24,900,000*	*01/2019*	*Unknown*

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

- Engineering Analysis, see Section 1.5.1
- FERC reqirements
- Operational Data of the number of times the spillgates are used per year

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.**

- Avista will receive upgraded spillgates, and associated appurtenances, once the project is complete
- Newly renovated spillgates, once complete, should require less maintenance ethat 70 year old spillgates.
- New technology integrated into the project may require up-front training and troubleshooting

The project is anticipating the following remaining costs:

2022 - $600,000

2023 - $3,100,000

2024 - $150,000

[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.

- Upgraded Spillgates will support the EIM iniative be ensuring the gates are functional to move as frequently as anticipated as part of Avista's participation in EIM
- Construction processes will make operating the all 8 spillgates impossible at once, for rthe duration of construction.
- Upgraded spillgates will support operations O&M expendaratures year-over-year

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

- Not doing anything—this was never an option because working on the gates is a FERC requirement
- Structural Reinforcement of select steel members—this was considered to be an interim fix until the gates could be repair or replaced. The business unit elected to not move forward with this because a larger gate project was on the horizon.

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 is continuing forward to strengthen the gate members identified. Construction activities will start in late 2022 and continue to mid to late 2024. Likely a portion of the project will become used and useful in 2022 and 2023, with the remainder in 2024. The means and methods and construction schedule have yet to be determined so exact timelines are unknown at this point in time. It is anticvipated to perform work on Gate #5 in late 2022, Gates 6, 7, and 8 in early 2023, and gates 1 through 4 in late 2023 and rolling into 2024.

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

This project emphasizes: reliability, safety, and the customer (through the end result of being able to support the EIM iniative.

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

See Section 2.5.

Additionally We are prudently investing money to understand what type of repair/repaclement/rehab is necessary. When we understand that, a second round of prudency will be entered when the project and the project steering committee will weigh the cost-benefits of each alternative.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

- Environmental
- Power Supply
- GPSS
- Supply Chain
- Exeternal Communications
- Asset Management
- Clark Fork Personnel

2.8.2 Identify any related Business Cases

No related business cases at this time

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

STEERING COMMITTEE MEMBERS

- Bruce Howard
- Scott Kinney
- Alexis Alexander

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

- Dam Safety Team
- Scott Kinney
- Alexis Alexander
- Bruce Howard

The project will be led by the core project team. Any changes to scope, schedule and budget will be submitted for approval to the steering committee and with the respective cost thresholds as defined in the project charter.

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

The project is utilizing the Project Change Log to track and manage all Project Change Requests (PCR) associated with the delivery of the construction project. The PCR describes the need for change, supplemental documentation, related project artifacts, change order proposals, and any other pertinent information. PCR’s are then signed for approval by the project approval thresholds, and then processed against the project risk registry, and or contract amendment with the contractor.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Noxon Rapids Spillgate Refurbishment BCJN 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:	8.25.22
Print Name:	PJ Henscheid		
Title:	Mgr, Civil and Mechanical Engineering		
Role:	Business Case Owner		

Signature:		Date:	9/2/2022
Print Name:	Alexis Alexander		
Title:	Direector, GPSS		
Role:	Business Case Sponsor		

Signature: ______________________ Date: ____________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

Noxon Rapids Unit 2 Stator and Core Replacement

EXECUTIVE SUMMARY

PROJECT NEED: The potential problem being address is the coils and the stator core. Unit 2 Stator and Core replacement is required due the age of the unit and core windings—the core is past it's current end of life design-life. The stator core is original and the last time we had the coils replaced there was hot spots that could not be fixed. There were two attempts to fix the hot spots by replacing laminations and restacking. The hot spots were reduced but not fixed. The coils will also be replaced during this project.

RECOMMENDED SOLUTION: The recommended solution is to replace the Core and Coils on the Generator.

ALTERNATIVES CONSIDERED:

- Alternative 1: Do Nothing
- Alternative 2: New Coils Only

COST OF RECOMMENDED SOLUTION: $10,000,000

ADDITIONAL INFO: This will improve the reliability of the Unit and keep one of our largest sources of power available to our customers. If this project is not approved, then upon a coil failure we would lose the 100 MW for the duration of the outage. We would have to move resources off one or two projects to address this. After assessing the damage, we could determine a path forward. In the past we have been able to do a half coil spice and put the unit back in service while we prepare for a replacement or rewind. The Unit might be restricted on the output depending on stator temperatures. We would have to move budgets, resources, and schedules.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Glen Farmer	Initial Version	5/27/2022	Started with NR U2 BCJN.
2.0	Glen Farmer	Updated with U3 data.	8/24/2022	
3.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 300,000	$ 0
2025	$ 5,750,000	$ 0
2026	$ 3,950,000	$ $10,000,000
2027	$ 0	$ 0
2028	$ 0	$ 0

Project Life Span	3 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

The Generator frame and core are original and replacement is required due the age of the unit and core windings—the core is past it's current end of life design-life. The Stator coils have been replaced during its life span. During the last rewind test were done on the core that showed several heating areas. There were two attempts to unstack and restack the core to reduce the heating areas. This reduced some of the heating areas but overall, there were signs of the core laminations having hot spots. It was decided to move forward with the rewind, and it was completed in 2004.

1.2 Discuss the major drivers of the business case

The major driver is asset condition. We continue to maintain the Stator and monitor the breakdown of the insulation. The insulation breakdown shows up in two ways. One is the white powder that is produced as the insulation is being broken down. The other is the partial discharge reading we receive while the unit is online. Both are indicators to help predict a failure. As these increases, we can do things like cleaning and changing the Y-point to reduce voltage stress. With these indicators we are trying to move to a predictive model of failure rather than reacting to the failure. The core is original and the last time we replaced the coils we were unable to remove the hot spots during core testing and restack. The core is made of sections and where these sections come together there is laminations deformation that causes the hot spots. With a new core the hope is we can eliminate these hot spots.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Using the predictive model allows for planning, budgeting, and scheduling the work so there is less disruption to the overall project flow. If this is not approved, then when there is a failure the resources and budget will be moved from other projects to address the failure.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. [Avista Strategic Goals]

The new generator contributes to the Safe and responsible design, construction, operation, and maintenance of Avista's generation fleet.

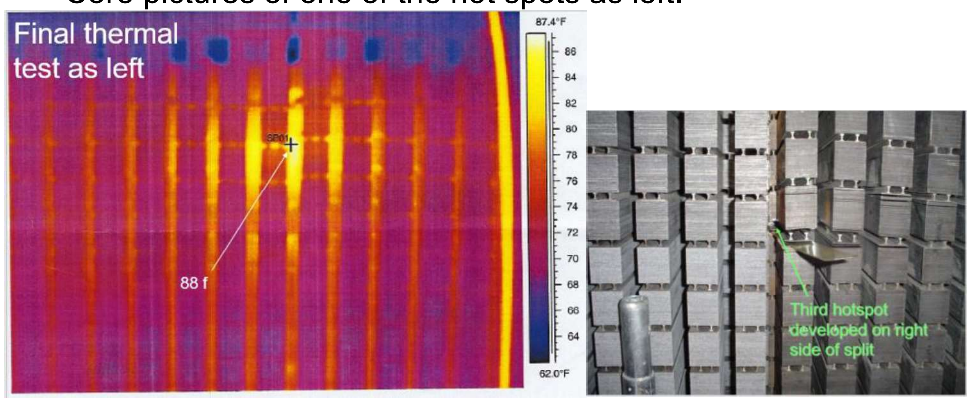
1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Noxon Rapids Unit 2 Stator and Core Replacement

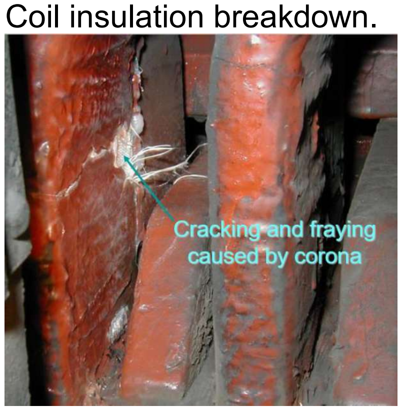
- During the last rewind test were done on the core that showed several heating areas. There were two attempts to unstack and restack the core to reduce the heating areas. This reduced some of the heating areas but overall, there were signs of the core laminations having hot spots. It was decided to move forward with the rewind, and it was completed in 2004.

- We have partial discharge data that has been turned into reports giving us a condition of the generator. We have spreadsheets that track the as found condition and as left condition of the coils during maintenance. We also have an overall condition assessment ranking of the current condition of the generator.

- Core pictures of one of the hot spots as left.



- Coil insulation breakdown.



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[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: The recommended solution is to replace the Core and Coils on the Generator. This will address the Core hot spots and the Coil insulation breakdown before a failure occurs.

In Scope: Engineering evaluation of the generator frame; Generator windings, generator core, core stacking mechanisms, and clamping mechanisms—all purchased new; sole plate updates; existing equipment will be removed and recycled; generator health monitoring system upgrades; balancing done by contractor with Avista assistance

Out of Scope: Major redesign of the upgrades; building/facility upgrades; air housing cooler replacement; generator frame upgrades

Assumptions: Design is the same as already created for Unit 1—it is anticipated there will be limited design services required.; This project will happen first of all the stator and core replacement projects at Noxon. Exciter will be replaced at the same time under a separate business case; any PLC upgrades will be performed under a separate business case; Avista labor will disassemble the generator, contract crews will rewind, Avista labor will reassemble.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- The first year will be engineering and getting contracts in place for a new core and coils. With the contracts in place then the manufacture will start the process of making the core laminations and winding the coils. In 2027 it is estimated to spend about $2,000,000. It is hard to say exactly where we will fit in the manufactures schedule. From experience it takes a full year to produce and deliver a core and coils. Payments will be made to the manufacture during the second year and that is estimated at $6,000,000. Once we know we are going to receive the equipment then we can take the Unit outage and start the process of removing the existing coils and core. The last year will be finishing the removal and putting in the new Core and coils. This is estimated at $2,400,000 to complete the project.

- CARS (Capital Additions and Retirement) form which documents added and removed assets associated with Avista's facilities. This document helps Avista maintain accurate continuing property records.

- The 2018 Hydro Generation Condition & Risk Assessments, is referred to as the "2018 Assessment." Early 2018 GPSS-Hydro department undertook an initiative to revamp their maintenance programs. This included the 2018 Assessment, which was conducted in the hydro plants and incorporated both Risk Assessments and Condition Assessments. Teams consisting of representatives from the Mechanic, PCM Tech, and Electric Shops, as well as Spokane River Hydro, Clark Fork River Hydro, and Maximo teams were formed and tasked with performing a condition and risk based assessment for assets in all of Avista's hydro facilities. Additional details may be found in the "2018 Hydro Asset Management Program Directory". The full reference is provided below:

  The Condition Assessments were based on the CEATI hydroAMP 2.0 guide. The database developed during the 2018 assessment has been used to create business information tools to identify and analyze equipment strategies to be used by GPSS for making business decisions.

  The purpose of the Risk Assessment was to identify the environmental, financial, and safety risks associated with each asset and what possible consequences might result from an asset failure. Consequences were framed within the Avista Business Risk Matrix. Financial risks might include lost generation during an outage. Probabilities were then estimated as an answer to the following question: Given an asset failure, what is the probability that a particular, potential consequence will actually occur? As an aid to this process, probabilities were selected from a menu of specified probability levels. Results of the Risk Assessments have been used to estimate asset risk costs. Risk cost is the product of the Failure Rate, Potential Consequence of failure. This risk cost is a probable dollar value associated with Avista's exposure risk of each asset.

  The results of the 2018 Assessment have been used to develop Asset Management Plans (AMPs) and a Risk Based Investment Planning (RBIP) tool. AMPs have been developed for a number of the asset classes, such as the generators, turbine runners, GSUs, trash rakes, etc. The AMPs outline capital and maintenance strategies. A primary purpose of the RBIP tool is to bring a risk-based perspective to the capital budget process.

  Reference - Avista Utilities, "2018 Hydro Asset Management Program Directory", Avista Utilities GPSS Dept., March 15, 2019

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

- Risk Cost calculation from GPSS Asset Management Group: Risk cost is the product of the Failure Rate, Potential Consequence of failure, and the Probability of experiencing the potential consequence in the event of a failure. This risk cost is associated with the probable dollar value associated with Avista's exposure risk of each component. This exposure risk includes the cost of anything that threatens the company, including costs associated with a probable failure of the components (potentially including replacement, refurbishment, or lost generation costs), safety risks associated with normal operation or replacement actions, and probable environmental risks associated with the asset, and at times other costs such as public perception risk mitigation activities. While the company may not be able to shelter itself from risk completely, there are ways it can help protect itself from the effects of business risk, primarily by adopting a risk management strategy as a part of the asset management program. Risk costs not only take account for the exposure risk for an asset but also the criticality (or importance of an asset) and its' current condition. Risk costs are somewhat analogous to insurance premiums. They represent an annual cost, but the year-to-year costs vary with the condition of the assets. If we total the risk costs for all of our assets for the next year, the company would need to have monies set aside for that year to cover the costs associate with the assets that fail that year.\

$$\begin{aligned}&Annual\ Risk\ Cost\\&= [Probability\ of\ Failure\ (that\ year)] \times [Consequence\ \$]\\&\times [Likelihood\ of\ actually\ experiencing\ that\ consequence]\end{aligned}$$

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$120,000	$120,000

It is estimated that the Maintenance offsets will be about $120,000 per year during the beginning of the maintenance cycle.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

Estimated indirect savings and/or productivity gains and associated benefits have not been quantified at this time; however, as applicable, please see the referenced Risk Based Investment report (see Section 2.2) for additional information.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: The recommended solution is to replace the Core and Coils on the Generator. This will address the Core hot spots and the Coil insulation breakdown before a failure occurs.

Alternative 1: Do Nothing; $0 Capital Cost

This alternative was not chosen due to several reasons. If we wait for a failure, then it is an unplanned event. The best scenario we could hope for is the Unit being down for at least four months. Depending on the time of year the Unit running and producing megawatts could be worth   This would allow us to get a contractor on board to do some temporarily repaired. This would disrupt the other projects that are in flight. If we were able to get a temporary fix in place the output of the Unit could be reduced. At this point we would start the process of a new Core and new Coils. There is no extra cost in this amount to try and get a better schedule from the manufacture. We would be going down the path of the recommended solution.

Alternative 2: New Coils Only; NA

This alternative was not chosen due to the issues we had with the Stator Core during the last rewind. We need to replace the core to eliminate the hot spots.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Elimination of Hot Spots.

2.7 Include A TIMELINE OF WHEN THIS WORK IS SCHEDULED TO COMMENCE AND COMPLETE, IF KNOWN.

☒Timeline is Known

- **Start Date:** 2024
- **End Date:** 2026

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/Governance Team

The steering committee consists of the following: Manager of Project Delivery, Manager of Maintenance and Construction, Manager of Hydro Operations & Maintenance.

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Noxon Rapids Unit 2 Stator and Core Replacement business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 11:00 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alexis Alexander EA27BABA767F467...	Date:	Aug-15-2023 | 6:50 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

Signature:	NA	Date:	
Print Name:	NA; no committees have been stood up at this time.		
Title:	NA		
Role:	Steering/Advisory Committee Review		

Peaking Generation

EXECUTIVE SUMMARY

Avista's Peaking Generation plants offer operational flexibility and are utilized to support energy supply needs. Thermal Peaking Generation power provides options for Avista's System Operations and Power Supply groups to maximize value to Avista and its customers. These plants represent more than 255 MW of power and include Rathdrum Combustion Turbines, Boulder Park Generating Station and Northeast Combustion Turbine, all natural gas fired power plants.

The operational availability for these generating units in these plants is paramount. The service code for this program is Electric Direct and the jurisdiction for the program is Allocated North serving our electric customers in Washington and Idaho. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

Projects completed under this program include replacement of failed equipment, replacement of equipment at their end of life, and small capital upgrades to plant facilities. The business drivers for this projects in this program is a combination of Asset Condition, Failed Plant, and addressing operational deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operational support issues. Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeopardize plant availability and greatly impact the value to customers and the stability of the grid.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Mike Mecham	Initial draft of original business case	7/8/2020	
1.0	Mike Mecham	Peaking Generation Business Case	6/22/2021	for 2022 - 2026
2.0	Mike Mecham	Peaking Generation business case	5/26/2022	For 2023 - 2027

Peaking Generation

GENERAL INFORMATION

Requested Spend Amount	$2,300,000
Requested Spend Time Period	5 years 2023 through 2027
Requesting Organization/Department	T07 / GPSS
Business Case Owner | Sponsor	Thomas Dempsey | Alexis Alexander
Sponsor Organization/Department	T07 / GPSS
Phase	Initiation
Category	Program
Driver	Asset Condition / Failed Equipment

1. BUSINESS PROBLEM

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

Due to the age and use of the peaking thermal generation facilities, some core assets, support systems and equipment are reaching the end of their useful life. In addition, it is difficult to predict failures and unscheduled problems of operating generating facilities. This program is critical in providing funding to support the replacement of core assets and systems that support the reliable operations of these facilities.

1.2 Discuss the major drivers of the business case

The major drivers for this business case are Asset Condition and Failed Plant. This program provides funding for small capital projects that are required to support the safe and reliable operation of these facilities. The flexible operations and generating capacity of these plants maximize value for Avista and our customers.

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

Asset age, hours of use and failed equipment jeopardize the safe and reliable operation of these generating facilities. If problems are not resolved in a timely manner, the plant and plant personnel could be at risk, and failed or unavailable assets and systems will limit plant flexibility and availability. This could have a substantial cost impact to Avista and our customers.

Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeopardize plant availability and greatly impact the value to customers and the stability of the 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.

Thermal Plants utilize plant reliability and availability metrics as well as in use hours to determine some of the projects. Historically, this program has funded multiple projects per year which contributed to unit availability and ensure reliability by completing hours based capital replacement or upgrades to equipment.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The historical drivers of the projects selected to be funded by the program are a mix of Asset Condition, used hours replacement of equipment, and Failed Plant. Projects are typically completed in the calendar year. The work is primarily performed in the 2rd and 4th quarters of the year when outage in the Peaking Thermal Plants are scheduled, typically during run off in the river systems or during milder weather conditions when power prices are low and it is most opportune to have the plants unavailable for projects.

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.

Being a program, this review will be performed on a project by project basis. This decision will be made by the program Steering Committee that consists of Thermal Management, Maintenance Engineering and Plant Personnel.

Option	Capital Cost	Start	Complete
Peaking Generation Program	$2,250,000	*01/2023*	*12/2027*
Individual Capital Projects	$2,250,000	*01/2023*	*12/2027*
Perform O&M maintenance	0		

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

Review of the program budget over the period of the last six years has revealed the a realistic annual budget is $500,000. In order to support the capital budget goals of the GPSS department, this budget was reduced in the short term for years 2023 through 2027 by 10%. Projects with lower risk will be delayed through this period.

The drivers of the projects selected to be funded by this program are mix of use hours based replacement, Asset Condition and Failed Plant. Resolving issues encountered in operating these plants in a timely manner benefits the customers with providing safe, reliable, low cost power which supports the needs of Bulk Electric System and provides value to Avista and our customers.

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 projects in this program typically take place during the outages which are in the late spring and fall of each year. Most of the capital is deployed in the 2rd and 4th quarter of each year.

If capital funds were not available for the projects in this program, reliability of the plant would decrease and more O&M would need to be performed to repair aging equipment instead of replacement. Due to the nature of the smaller Capital projects covered under the Peaking Generation Program, forced outages and reliability are difficult to quantify. Should forced outages occur due to the inability to cover Capital projects under this program, daily estimated Power Supply outage costs associated with the Peaking Generation facilities covered under this Program are estimated to be:

Rathdrum CT: $3,800

Boulder Park GS: $1,300

Northeast CT: $1,200

(refer to 20220825 Thermal Daily Outage Cost Estimation Tool CONFIDENTIAL.xlsx)

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

These projects vary in size and support needed from the Department and key stakeholders. The larger projects require formal project management with a broader stakeholder team. Medium to small projects can be implemented by a project engineer or project coordinator and many cases can be handled by contractors managed by the Thermal personnel, including Management and engineering. All of these projects are prioritized and coordinated by the broader support team.

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

One alternative would be to create business cases using the business case template and process for each of these small projects. There are typically 10 to 15 projects a year funded by the program. This would overload the Capital Budget Process with small to medium projects whose governance can be effectively handled by the Thermal Group. These projects are specific to these plants and the leadership in the Thermal Group understand best the nature and context of these projects.

These projects are, at times, unpredictable. It would be difficult to forecast unforeseen events such as equipment failures and identify critical asset condition that could effectively be put in the annual capital plan.

Another alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their lifecycle. This will be unacceptably expensive and older equipment will become more and more unreliable until it becomes obsolete. Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to unacceptable risk.

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 in this program typically take place during the outages for the Peaking Thermal Plants, which are typically in the spring and fall of each year. Some projects may have the ability to be performed during non-outage times.

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

The purpose of this program is to provide funding to small to medium size projects with the objective of keeping our Peaking Generation plants reliable and available to support the power needs of our company and our customers affordably. By doing this we support our mission of improving our customer's lives through innovative energy solutions which includes Peaking Thermal generation. By executing the projects funded by the program, we insure that Peaking Generation Facilities are performing at a high level and serving our customers with affordable and reliable energy.

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

Review of the program budget has revealed that a realistic annual budget is $500,000. The 5 year historical average spend in the Peaking Generation Program is $460,000. In order to support the capital budget goals of the GPSS department, this budget was reduced in the short term for years 2023 through 2027 by 10% per year. Projects with lower risk will be delayed through this period.

The drivers of the projects selected to be funded by this program are mix Asset Condition and Failed Plant. Resolving issues encountered in operating these plants in a timely manner benefits the customers with providing safe, reliable, low cost power which supports the needs of Bulk Electric System and provides value to Avista and our customers.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The list of primary customers and stakeholders includes: GPSS, Environmental Resources, Power Supply, Systems Operations, ET, and electric customers in Washington and Idaho.

2.8.2 Identify any related Business Cases

None

3.1 Advisory Group Information

The Advisory Group for this program consists of the GPSS Asset Management and

Compliance Engineering team, Thermal Plant Operations Manager, Thermal Maintenance Engineering and the Manager of Thermal Operations and Maintenance.

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

Projects are proposed through various organizations in Generation Production and Substation Support (GPSS) and through key stakeholder such as Environmental Resources, and Safety and Security. The projects are vetted by the Thermal Advisory Group. With the assistance of Operations, Construction and Maintenance and Engineering, projects are evaluated to determine available options, confirm prudency, and bring potential solutions forward.

This same vetting process is followed for emergency projects and may included other key stakeholders. Over the course of the year, the program is actively managed by the Thermal Operations Manager, with the assistance of the Advisory Group. This includes monthly analysis of cost and project progress and reporting of expected spend.

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

Each project request will be evaluated by the Advisory Group which will include the scope, cost and risk associated with the project. The project will be evaluated based on the impact or potential impact of the operation of the Peaking Generation plants. The selection and approval of the project will be based on the experience and consensus of the Advisory Group.

Depending on the size of the project, a Project Manager or Project Coordinator may be assigned. They will follow the project management process for reporting and identifying and executing change orders. Smaller projects will have a point of contact and financials will be review on a monthly basis by the Advisory Group.

Peaking Generation

The undersigned acknowledge they have reviewed the Peaking Generation Program business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Mike Mecham Digitally signed by Mike Mecham Date: 2022.08.31 11:20:04 -07'00' Date: ____________

Print Name: Mike Mecham

Title: Manager, Plant Ops Thermal

Role: Business Case Owner

Signature: Alexis Alexander Digitally signed by Alexis Alexander Date: 2022.09.02 15:59:09 -07'00' Date: ____________

Print Name: Alexis Alexander

Title: Director, GPSS

Role: Business Case Sponsor

Signature: ____________ Date: ____________

Print Name: ____________

Title: ____________

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name:

GPSS Peaking Generation Program

2. Business Case Owner:

Thomas Dempsey

3. Director Responsible:

Andy Vickers

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

Response:

Quantified direct savings:

2022	2023	Lifetime

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Response:

The Peaking Generation Program provides funding to Boulder Park GS, Northeast CT and Rathdrum CT for small to medium size projects. This Program consists of multiple projects between the three generating facilities focusing primarily on a mix of planned equipment replacement projects and failed plant projects. These projects replace failed, damaged, and underperforming equipment to ensure plant reliability and availability are maintained at a high level. One project has been identified for Boulder Park Generating Station in 2022 is rewinding a failed generator and using it as a Capital Spare in case of another generator failure.

Asset analysis of some of the projects nested in the Peaking Generation Program results in the “Risk Cost Reduction” shown below, reflective of the premium that would be paid if we were to insure against asset failure during this time frame. This calculated indirect savings considers the condition of the asset, the probability of failure, the probable consequence of failure and other risk factors such as personnel and public safety, environmental impacts, and unplanned outages and repairs.

Quantified indirect savings:

2022	2023	Lifetime
$9,845	$11,021	$306,284

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista’s customers will endure due to non-compliance.

Response:

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

Director Name ___________Andy Vickers___________________________________

Director Signature ________ ___________________________________

Date ____________________10/27/2021__________________________________

Post Street Substation Crane Rehab

EXECUTIVE SUMMARY

The 35 Ton Niles Bridge Crane at the Post Street Substation is original to 1907 and services the interior of the building. The primary function for this crane is to service the Upper Falls and Monroe Street GSU's, substation 115kv transformers, switchgear, and miscellaneous other substation equipment. It is a low frequency of use, high consequence if unavailable when needed, piece of equipment.

The crane's controls and electrical are mostly original and have degraded in capability over time. Recent experience with the crane exhibited issues with controls and overheating/stalling with extended use. The current state of electrical components on this crane are not capable of supporting the pick of a transformer without extensive refurbishing. This negatively impacts the ability to respond to a failure in a critical downtown substation and increases risk. The problem is aggravated by the lack of ability to use a large enough standard mobile crane inside the building as an alternative.

The recommended solution includes a replacement of the existing crane electrical and controls, refurbishment of the mechanical components, and replacement of the existing hoist and trolley system with a modern arrangement. This approach is a modern in-kind replacement of the current substation crane and would provide a lasting solution to meet current and future demands.

The estimated cost of the project is $2,134,000 in order to fully rehabilitate the crane. The service code for this program is Electric Direct and the jurisdiction for the project is Allocated North serving our electric customers in Washington and Idaho. Operating Post Street safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ryan Bean	Initial draft of original business case	5/10/2022	
1.0	Ryan Bean	Update	8/2/2022	Updated based on past actual costs and equipment lead time.

GENERAL INFORMATION

Requested Spend Amount	$2,134,000
Requested Spend Time Period	3 years
Requesting Organization/Department	C07/GPSS
Business Case Owner | Sponsor	Ryan Bean | Alexis Alexander
Sponsor Organization/Department	C07/GPSS
Phase	Initiation
Category	Project
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

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

The 35 Ton Niles Bridge Crane at the Post Street Substation is original to 1907 and it's electrical and controls are beyond their useful life. The Primary function for this crane is to service the Upper Falls and Monroe Street GSU's, substation 115kv transformers, switchgear, and miscellaneous other substation equipment. In it's current state, it's is unlikely the crane could support restoration efforts for a major equipment failure, thereby placing future repair or refurbishment activities at risk. Restoring this cranes' capability will enable response to a failure in this critical downtown substation and prepare the site for future projects.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer.

The driver for this business case is Failed Plant. The crane has exceeded it's useful life and is not likely able to perform the function needed to support the substation and generator transformers. Post Street Substation supplies power to a significant portion of downtown Spokane, as well as serving as a conduit for Upper Falls and Monroe Street generating stations which supply year-round base load hydroelectric power. Continuing to operate Post Street safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

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

The current state of electrical components on this crane is unlikely to support the pick of a transformer without extensive refurbishing. This negatively impacts the ability to respond to a failure in this critical downtown substation and increases the risk to our ability to reliably serve our customers. Without mitigating the risk, the company would continue to be exposed to an uncertain recovery for any major work needed at the facility.

While the Downtown Network has full redundancy, the substations that provide that redundancy both have risks associated with them. The Metro Substation is being replaced, but the new Metro Substation won't be in place until at least 2026. The Post Street Substation (where the crane to be replaced is located) is the other substation servicing downtown Spokane. While not quite at the point of needing replacement, like Metro, the Post Street station is also dated. Having a failure of a transformer at the Post Street Substation and not being able to replace it would leave the downtown relying on Metro Substation, which is well past its useful life, as evidenced by the approved business case to replace it.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The measure of success would be in restoring the capabilities of the crane to provide the lifting services needed at the location. This could be captured via a successful post rehab load test, reduced O&M for crane repairs, and decreased risk to future project schedules due to crane down time.

1.5 Supplemental Information

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

A crane assessment and evaluation was performed on Dec. 1, 2021 by Simmers Crane. At a high level, the assessment found the electrical components/controls for the bridge and trolley to be beyond service life and at risk for failing the main functions of the crane. It was highly recommended to replace all existing electrical controls on this crane.

The current mechanical condition of this crane appear to be acceptable, though all of the hoist gearing is showing signs of misalignment wear and further use of this crane could lead to extensive wear of mechanical parts. Mechanical parts can still be sourced through Kone crane, though the price and availability of these parts is less than ideal and thus a new trolley and bridge drives is being recommended

Please see also:

- Annual Crane Inspection Reports by PCI (2010-2021) with findings of related deficiencies.
- 2002 Load Test

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 metric supporting the replacement of the current crane is that it is beyond it's useful life and is no longer able to perform the function required. Major repairs to equipment may not be feasible and future projects will be impacted without a crane readily available.

Option	Capital Cost	Start	Complete
Alternative 1: Minimal Repairs	$200,000	08 2022	6 2023
Alternative 2: In-Kind DC Control System	$1,200,000	08 2022	12 2023
Alternative 3: **Recommended Alternative** – New hoist/trolley and AC Controls on Existing Bridge Frame	$2,134,000	08 2022	6 2024
Alternative 4: Install a New Crane	$2,500,000	08 2022	6 2024

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

A Crane Assessment and Evaluation was performed By Simmers Crane on Dec 1st 2021 to establish the existing condition and recommended actions. The report informed a high-level Alternatives Analysis performed by GPSS Mechanical Engineering with budgetary cost estimates based on multiple manufacturer's input and past crane overhaul experience.

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 cost will be spread out over three years 2022-2024. 2022 will be primarily design and contracting totaling $250,000. 2023 would include procurement, fabrication, and construction estimated at $1,730,000. 2023 will include as builds and project closeout site totaling $154,000. This will not offset significant O&M charges because many of the crane components are beyond service life and are unable to be maintained.

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

Fortunately, the Post Street Crane is not often used and it being unavailable will result in little impact to normal operations. If there is a transformer failure, the primary business function impacted will be Generation and Substation response time. 115 kV breaker failure, PT failure, underground line termination failure, switchgear failure, and many other miscellaneous pieces would also be difficult if not impossible to respond to. This could affect reliability of the 115 kV BES as well as other Generation and Distribution components.

Constructability details will need to be identified by the project team, which may impact substation operations during the construction window. Any impacts to Substation and System Operations will be discussed and planned with the respective parties to mitigate impacts.

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

Alternative 1: Minimal Repairs

- Clean all electrical components before use
- polish conductor wire for trolley and bridge
- Replace all loose bolts noted in inspection
- Replace worn collector shoes on trolley
- Inspect and adjust brake on main hoist motor
- Mount a fan near resistor bank to keep cool
- Perform test crane pick to evaluate capacity

This crane is electrically outdated making most components obsolete or difficult to obtain and costs associated with making or attaining parts is unknown and a risk to the budget. There are no guarantees that any of this work will make the crane suitable for future use. There are also high safety risks associated with this existing equipment as many electrical components are exposed and not contained from accidental operator contact. The existing design of the crane also does not meet current OSHA and CMAA standards

Alternative 2: In-Kind DC Control System

- Full Non-Destructive Examination of all moving components
- New DC main feed rails down length of runway

- New DC trolley festoon system
- Reuse existing trolley and bridge drive components
- Replace worn bushings on trolley/hoist
- Radio transmitter for wireless operation
- Misc. upgrades to meet current crane design and safety standards

The crane would be upgraded to a modernized DC system capable of running the existing mechanical components and adding radio controls to crane. DC controls are more specialized engineering and there is a potential risk of excessive cost associated. All warn bushings would need to be custom manufactured and replacement costs will be substantial. There is a risk the NDE results will require replacement of parts. Any part needing replaced has an unknown cost associated. This option poses risk of using exiting components for long term crane use and does not provide extended service life equal to options 4 and 5. Maintenance costs are also expected to be higher throughout extended service life as compared to options 4 & 5 due to continued use of bushings on rotating equipment and DC motors. The work and cost required to replace worn items and correct the misalignment issues would be excessive and a new trolley would likely be more cost effective. It should be noted that the trolley frame construction is mainly cast iron, and the equipment mounted directly to cast iron framework. This construction is often difficult to upgrade with any new equipment due to the inability to weld. This option is also not recommended due to use of DC system in an AC supplied facility.

Alternative 3: **Recommended Alternative** – New Hoist/Trolley and AC Controls on Existing Bridge Frame

- Upgrade power feed to 480 VAC
- New AC conductor bar down length of runway
- Modernize hoist, trolley and controls
- New AC trolley festoon system
- Radio transmitter for wireless operation
- New Bridge drive components
- Inspect Bridge wheels for reuse
- Misc. upgrades to meet current crane design and safety standards

The new hoist, trolley and bridge drive would be vfd controlled for smooth and safe operation of the crane. This option will also eliminate all outdated electrical components and upgrade to a standard 480v system that is consistent with similar equipment at other Avista facilities and in the industry. This is the option that was chosen at both LF and LL facilities for crane upgrades and is the recommended upgrade by GPSS engineering. Removing the old trolley and installing the new trolley will pose some challenges and may require roof entry of mobile crane as was done at LF. This option is beneficial for extended service life of the crane and to reduce maintenance costs as well. The extended service life will nearly match that of a new crane without the additional materials and installation costs associated.

Alternative 4: Install a New Crane on Existing Runway

- Demo existing Niles Crane
- Runway structural engineering to confirm capacity with new crane
- Replace with new crane (end trucks, bridge girders, trolley, & hoist)
- Upgrade power feed to 480 VAC
- New AC conductor bar down length of runway
- New bridge walkway
- Radio transmitter for wireless operation
- New crane meets all updated codes and safety regulations

Removal of the existing crane structure and installation of a new crane structure poses higher risk and constructability than other options and will require multiple overhead cranes and in-depth planning and engineering to accomplish. This option would also have the potential to require longer outages for the 115v portion of the sub near the demo and install. There are also unknowns associated with the structural engineering involved for the existing runway that is required under this option. A new crane would guarantee the longest extended service life of any of the options presented. This option also has the possibility of increasing the crane capacity to be able to lift a transformer without following strict engineered pick procedures. The method for demo of old crane and install of new crane is still undefined and is expected to be the largest difference in cost between this option and option 3.

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 project is expected to take 12 months starting in 2022 and ending in 2023. The effort in 2022 will be devoted to design, equipment sourcing, and fabrication. The effort in 2023 will consist of site mobilization, construction, and commissioning of the crane. The crane will not become used and useful until successfully passing a load test during commissioning in 2023.

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

Operating Post Street Substation safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System. By taking care of this crane, we improve our reliability and support our mission of improving our customer's lives through innovative energy solutions, which includes hydroelectric generation. By executing this project, we ensure that Post Street Sub, Upper Falls, and Monroe Street generation stations will continue to provide reliable service to our downtown customers and mitigate risk to future projects and unplanned failures.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Industrial cranes of this size and complexity fall into this range of cost based on manufacturers estimates and past in-house experience with crane rehabilitation. We are currently operating at risk at this location with being unable to respond to a major equipment failure in a timely manner, thereby incurring lost generation impacting customers.

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

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are the Regional Plant Manager and Operations crew on the Upper Spokane, GPSS Engineering, GPSS

Construction and Maintenance, Substation Engineering, and System Operations. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

No current dependent Business Cases.

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

Post Street Substation Crane Rehab

The undersigned acknowledge they have reviewed the Post Street Substation Crane Rehab 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 Bean Digitally signed by Ryan Bean Date: 2022.08.31 11:08:00 -07'00'	Date:	
Print Name:	Ryan Bean		
Title:	Plant Manager, Upper Spokane		
Role:	Business Case Owner		

Signature:	Alexis Alexander Digitally signed by Alexis Alexander Date: 2022.09.02 16:04:19 -07'00'	Date:	
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:	Glenn Madden		
Title:	Manager, Substation Engineering		
Role:	Steering/Advisory Review		

Template Version: 05/28/2020

Upper Falls – Trash Rake Replacement

EXECUTIVE SUMMARY

The trash rake has, since its installation, presented an environmental risk due to the hydraulic system that utilizes to function. When in use, the hydraulic system is suspended over the Upper Fall unit intake and the Spokane River. Should a hydraulic line fail during raking operation, some amount of hydraulic fluid would end up in the river, leading to an environmental cleanup exercise. The current trash rake is undersized, leading to issues during raking operations. Often, the rake stalls out mid-operation due to the weight of accumulated debris it is trying to recover. The rake is also limited in its ability to lift logs and tress which can accumulate in front of the rakes, leading to potential personnel safety issues with operators being required to cut up the logs and trees while in very close proximity to the river's edge. Often times this is an operator leaning out over the handrail to address the problem. A safety action item was identified in 2016 related to the conveyor system that the trash rake utilizes to accumulate cleaned debris into a dumpster. This conveyor system, at the time posed a personnel safety threat due to its open operating nature. The risk of someone becoming entangled in the operating conveyor system drove a safety switch to be installed.

The recommended alternative is to replace the trash rake with an appropriately sized system that will allow full reach of the intake racks and accommodate large sized trees and logs to be removed from the river. This alternative would either replace the conveyor belt system with a new and safer alternative type of debris conveyance system or would remove that system entirely. This alternative is likely to be a packaged device with modern controls and electrical systems. The overall project cost of this alternative is estimated at $1,500,000. Should this project be delayed, the operational safety and environmental issues would still be present, posing associated risks into the future.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*PJ Henscheid*	*Format existing BC into exec summary*	*7.2.20*	*5-year Capital Planning Process*
2.0	*PJ Henscheid*	*Completion of full BCJN document*	*8.4.20*	*5-year Capital Planning Process*

Upper Falls – Trash Rake Replacement

GENERAL INFORMATION

Requested Spend Amount	$1,500,000
Requested Spend Time Period	*2 years*
Requesting Organization/Department	J07/GPSS
Business Case Owner | Sponsor	PJ Henscheid | Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The major driver for this business case is asset condition. The existing trash rake at Upper Falls is an articulating arm Atlas Polar device.

The trash rake has, since its installation, presented an environmental risk due to the hydraulic system that utilizes to function. When in use, the hydraulic system is suspended over the Upper Fall unit intake and the Spokane River. Should a hydraulic line fail during raking operation, some amount of hydraulic fluid would end up in the river, leading to an environmental cleanup exercise. While the rake is in its parked position, the hydraulic system is in very close proximity to the river and poses a threat to leaking.

The current trash rake is undersized, leading to issues during raking operations. Often, the rake stalls out mid-operation due to the weight of accumulated debris it is trying to recover. The rake is also limited in its ability to lift logs and tress which can accumulate in front of the rakes, leading to potential personnel safety issues with operators being required to cut up the logs and trees while in very close proximity to the river's edge. Often times this is an operator leaning out over the handrail to address the problem.

A safety action item was identified in 2016 related to the conveyor system that the trash rake utilizes to accumulate cleaned debris into a dumpster. This conveyor system, at the time posed a personnel safety threat due to its open operating nature. The risk of someone becoming entangled in the operating conveyor system drove a safety switch to be installed.

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 Asset Condition. Having an effective and reliable trash cleaning device is imperative for the continued efficient operation of our Hydro generating units. Replacing this trash rake will not only provide for the safety of our operations staff, but will encourage the reliable operation of Upper Falls HED which contributes to the successful implemtnation of our Spokane River license.

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 address the personnel safety issues related to the converyor system of the existing trash rake as well as address the potential environmental risks present with the existing design. Both of these risks remain if this work is deferred or not performed.

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 effective operation of upper falls hed will signify successful implementation of this project, but more importantly addressing the personnel safty risks as well and the environmental risks present in the current design will determine project success.

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.

Knuckle Boom	Marginal	4.67
Trashrake	Marginal	4.00

The above table is from the Net Condition Index and Rating summary. This information was compiled during the maintenance assessment of all Hydro assets performed in 2018. As shown, the condition of both the knuckle boom and trash rake are currently marginal, and do take into account the safety and environmental risks.

The recommended alternative is to replace the trash rake with an appropriately sized system that will allow full reach of the intake racks and accommodate large sized trees and logs to be removed from the river. This alternative would either replace the conveyor belt system with a new and safer alternative type of debris conveyance system or would remove that system entirely. This alternative would likely still utilize hydraulics to function, however, a robust containment system would be required and modern control system can detect and shut off the system when a leak is identified, often resulting in very small amount of leakage reaching the waters surface. This alternative is likely to be a packaged device with modern controls and electrical systems.

This alternative would likely include some amount of concrete work to facilitate and support the installation of a new trash rake. This could also include some concrete demolition and removal and replacement of embedded components.

This alternative would allow for reliable and safe operation and cleaning of the intake racks at Upper Falls, and would take into full consideration all personnel safety issues highlighted to date, as well as identify and address other possible safety issues.

This alternative is anticipated to begin in 2023, with an engineering assessment design starting that year. Construction could start as soon as early fall 2024. The project is anticipated to be transferred to plant sometime in 2025.

Option	Capital Cost	Start	Complete
Repace Upper Falls Trash Rake	$1,500,000	01/2023	12/2024
Alt 1: Do Nothing	$0	NA	NA

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

Data compiled from the replacement of the trash rake at Nine Mile in 208 helped to inform this capital request. It is anticipated the new trash rake at Upper Falls could be very similar in nature, both in scope of supply and operationally, to what was installed at Nine Mile.

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.

Some O&M cost savings are anticipated to be realized as a result of this project in reducing the amount of repairs and maintenance need to be performed on the trash rake. Also, the intent of the new design would allow for a safe and effective one person cleaning operations instead of the current practice of two operations personnel.

2023 – Engineering design and procurement of some of the equipment is anticipated

2024 – Completion of procurement and construction is anticipated

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

Operations and Power Supply will be impacted by this business case during implementation. Upper Falls generating unit will be required to be off-line during the totality of construction. This will affect plant operations and power supply, and will require all river flows to pass through the Control Works spillgates. The duration of construction activities is unknown at this time.

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

Alternative 1 – Do Nothing

This alternative would not allow for improving the functionality of the trash rake nor remove any of the safety risks associated with the existing rake.

The major risk associated with this alternative is the unreliable operation and personnel safety and environmental risks associated with the existing design. This alternative would continue to affect the Operation and Maintenance budget as repairs continue to be an issue and the equipment continue to age. Downtime for the plant could likely increase if outages of the trash rack increase due to age.

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.

Design efforts would kick off in 2023, with vendor selection, site visits and design analysis. Design should be completed by mid to late 2023, and propcurement of equipment would commence. The majority of the scope of supply is anticipated to be delivered in early 2024, with construction activities starting as early as June of 2024 – following spring run-off. Construction is anticipated to take most of the summer and fall of 2024, with an anticipated transfer to plant of the entire project of the end of 2024.

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

The delivery of this project is highly important in the sustainability and operations of our Spokane river facilities and operating them safely and responsibly. The project will focus of the people responsible the delivering with a strong emphasis on performance. This nature of the project demands a collaborative environment with the wide array of key stakeholder groups. This will address personnel safety issues, environmental concerns, and unit reliability all at the same time.

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 project budget and total cost will be regularly reviewed with the project steering committee, as well as, receive approvals as described below for any changes in scope and cost. Prudency is also measured by remaining in compliance the FERC License such that we can continue to operate Spokane River dams for the benefit of our customers and company.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

- GPSS Engineering; Civil, Mechanical, Electrical and Controls
- Hydro Operations
- Environmental, Permitting, and Licensing
- Master Scheduler
- Asset Management
- Project Accounting, Finance, and Rates
- Supply Chain and Legal
- Corporate Communications
- Construction Inspection and Project Management

2.8.2 Identify any related Business Cases

This project has no other relevant business cases.

3.1 Steering Committee or Advisory Group Information

The advisory group for this project will consist of members from the Generation Production and Substation Support department, Power Supply, and the Environmental department. Specific individuals of the steering committee will be selected at a later date by the GPSS leadership team. Advisors are provided with monthly project status reports but, are only convened in the event of a necessary decision point.

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

The project will be led by the core project team. Any changes to scope, schedule and budget will be submitted for approval to the steering committee

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

The projectis anticipated to utilize the Project Change Log to track and manage all Project Change Requests (PCR) associated with the delivery of the construction project. The PCR describes the need for change, supplemental documentation, related project artifacts, change order proposals, and any other pertinent information. PCR’s are then signed for approval by the project approval thresholds, and then processed against the project risk registry, and or contract amendment with the contractor.

The undersigned acknowledge they have reviewed the Upper Falls Trash Rake 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: Date: 8/4/20

Print Name: PJ Henscheid

Title: Mgr, Civil and Mechanical Engr

Role: Business Case Owner

Upper Falls – Trash Rake Replacement

Signature:		Date:	8/4/2020
Print Name:	Andy Vickers		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

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

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name: **Upper Falls Trash Rake Replacement**

2. Business Case Owner: **PJ Henscheid**

3. Director Responsible: **Andy Vickers**

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

The replacement intake rake is not anticipated to be faster or more efficient but will address safety concerns as described in the Business Case Justification Narrative and captured below in Risk Cost Reductions. The replacement rake will also not impact operations and maintenances costs as associated with the existing rake as the new rake will require similar maintenance as the existing.

Quantified direct savings:

2022	2023	Lifetime
N/A	N/A	N/A

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Asset analysis of this project results in the "Risk Cost Reduction" shown below, reflective of the premium that would be paid if we were to insure against asset failure during this time frame. This calculated indirect savings considers the condition of the asset, the probability of failure, the probable consequence of failure and other risk factors such as personnel and public safety, environmental impacts, and unplanned outages and repairs.

Quantified indirect savings:

2022	2023	Lifetime

$29,754	**$31,628**	**$304,602**

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

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

Director Name _____Andy Vickers_______________________________

Director Signature ______ ______________________________________

Date ________________________10/26/2021________________________________

Cabinet Gorge Dam Fishway

EXECUTIVE SUMMARY

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The Clark Fork Settlement Agreement (CFSA) and FERC License require Avista to implement the Native Salmonid Restoration Plan (NSRP), which includes a step-wise approach to investigating, designing and implementing fish passage at the Clark Fork Project. Appendix C of the CFSA commits Avista to fund the Cabinet Gorge Dam Fishway (Fishway) design and construction as well as annual operations and maintenance. Additionally Avista is required to evaluate and optimize the operation of the Fishway by implementing the Monitoring and Evaluation Plan. Fish passage is intended to restore connectivity of native salmonid species in the lower Clark Fork watersheds. During relicensing the U.S. Fish & Wildlife Service (USFWS) reserved its authority under Section 18 of the Federal Power Act to require fish passage at both Noxon Rapids and Cabinet Gorge dams, in order to pursue the NSRP more collaboratively. Those efforts, including involvement of Native American tribes and state agencies, as well as other stakeholders, continued over 15 years to the current project.

The Agreement and License support all electric customers in Washington and Idaho by authorizing the continued operation of Noxon Rapids and Cabinet Gorge dams. In Amendment No. 1 to the CFSA, Avista agreed to construct and operate a permanent upstream fishway facility, consistent with the objective and purpose of the design approved by a Design Review Team (DRT) on January 13, 2013, and modified to include a two-chamber trap and siphon water supply approved by the DRT in July 2017. Any subsequent changes to the design that may affect the design criteria identified in the final Basis of the Design Report would require approval by the USFWS. This agreement provides protection for Avista from being ordered to build alternative facilities at Cabinet Gorge for the term of the FERC License and also satisfies obligations under the Endangered Species Act as well as Federal Power Act Section 18. The construction of the Fishway was successfully completed Q2 of 2022. Approval of this business case will benefit our customers by maintaining compliance with the CFSA and FERC License and subsequent agreements, which provide operational flexibility at Avista's Noxon Rapids and Cabinet Gorge Hydro-Electric Facilities.

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VERSION HISTORY

Version	Author	Description	Date
1.0	*Monica Ott*	*Revsion to new Business Case template and content update*	*8/21/23*
BCRT	*Heidi Evans*	*Has been reviewed by BCRT and meets necessary requirements*	*9/30/23*

Cabinet Gorge Dam Fishway

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$600,000	$600,000
2025	$400,000	$400,000
2026	$100,000	$100,000
2027	$100,000	$100,000
2028	$100,000	$100,000

Project Life Span	*50 year*
Requesting Organization/Department	B04 / Clark Fork License
Business Case Owner | Sponsor	Monica Ott / Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
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?

Cabinet Gorge Dam blocks upstream passage for key fish species to spawning tributaries. To address these impacts to fisheries, a fish passage program requirement was incorporated into the Clark Fork Settlement Agreement and FERC License No. 2058 issues for the Clark Fork Project in 2001. Design, Construction and Operation of the Fishway partially fulfills the upstream fish passage requirements.

1.2 Discuss the major drivers of the business case.

Investment Drivers

The investment driver associated with the CFSA and FERC License fall under Mandatory and Compliance. Benefit to our customers and the company is the ability to provide clean, reliable and cost-effective power.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Avista, working closely with interested stakeholder groups, began implementation of an Upstream Fish Passage Program for Bull Trout in 2001 as part of Appendix C of the CFSA. A similar program for Westslope Cutthroat Trout was initiated in 2015, and the results of this study help inform fish passage decisions. Bull Trout are listed as threatened under the Endangered Species Act and Westslope Cutthroat Trout are a species of specific concern in both Montana and Idaho. A number of fish collection methods have been employed to capture these fish in order to transport them upstream of the dams. The use of these methods has resulted in some level of fish capture success; however, there is evidence the majority of the fish that are approaching Cabinet Gorge Dam are not being captured and not all fish that are captured are captured the first time they approach the dam. The Fishway was constructed to capture a larger number of the migratory native salmonids that are approaching Cabinet Gorge Dam. The goal of construction and operation of the CGDF is to provide timely and effective upstream passage for native trout species in support of broad native salmonid recovery and connectivity in the lower Clark Fork watershed. The signatories to the CFSA agree that the construction and operation of upstream and downstream fishways, and the provisions in Amendment No. 1 to the CFSA is in the public interest and that it satisfies various agency authorities applicable to the Project. Critical among the authorities cited are Section 18 of the Federal Power Act, the Endangered Species Act, the Clean Water Act, state fishway and transport regulations, and USFWS's 1999 Biological Opinion for licensing and operating the Project for the term of the License.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization.

Avista Strategic Goals

The delivery of this project is highly important in the sustainability and operations of our Clark Fork River HED facilities and operating them safely and responsibly. The project will focus on the people responsible for the delivering with a strong emphasis on performance. The nature of the project demands a collaborative environment with a wide array of key stakeholder groups. These efforts align with Avista's values of collaboration and environmental stewardship.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

The CFSA under FERC License No. 2058 issued for the Clark Fork Project in 2001, and Amendment No. 1 of the CFSA both stipulate that Avista will construct a fish passage facility for Bull Trout at Cabinet Gorge Dam.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Construction and successful operation of the Cabinet Gorge Dam Fishway is a requirement of the Clark Fork FERC License and CFSA. Compliance with these obligations allows the continued operations of Cabinet Gorge and Noxon Rapids dam, maintains relationships with the stakeholders making management decisions of Avista's obligated funding, and is in Avista's best interest for continued operational flexibilty on the Clark Fork River.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Operation of the Cabinet Gorge Dam Fishway is a requirement of the Clark Fork FERC License and CFSA.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

There are no quantifiable direct savings for implementing this compliance element of the Clark Fork Settlement Agreement and FERC License. Construction of the Fishway is required under the CFSA. Making the Fishway successful will provide cost saving in the future as other methods of fish passage currently employed will not need to be used and Avista will likely not be required to construct a new facility during the next relicensing of the Clark Fork Project.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

There are no quantifiable in-direct savings for implementing this compliance element of the Clark Fork Settlement Agreement and FERC License. Construction of the Fishway is required under the CFSA.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

No alternative exists for construction of a fish passage facility at Cabinet Gorge Dam (see above). This plan is a result of our FERC License requirements and subsequent negotiations. If Avista does not build a fish passage facility at Cabinet Gorge Dam, FERC could issue orders, penalties or even rescind our operating license. Additionally, the USFWS could take legal action under Section 18 to order Avista to build the facility, with none of the assurances enacted by agreement in the CFSA Amendment No. 1.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Avista is implementing a robust monitoring and evaluation plan that includes fish monitoring devices both downstream of the Fishway and at strategic locations in the Fishway. The fish monitoring devices will provide valuable information on the presence of tagged Bull Trout and Westslope Cutthroat Trout in the area. These metrics will be used to evaluate the success of the Fishway including the ability of flow in the Fishway to attract target species to the Fishway and whether or not fish are attracted into the final capture pool.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is an ongoing commitment running with the Clark Fork FERC License No.2058 and will continue until the License expires in 2046.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Avista and over 20 other parties, including the States of Idaho and Montana, various federal agencies, five Native American tribes, and numerous Non-Governmental Organizations form the Clark Fork Management Committee which has ultimate authority on actions and budgets for the Fishway. In addition, we coordinate with numerous internal stakeholders, in particular within GPSS and Power Supply. The steering committee for the Fishway is made up of representatives from GPSS and Environmental.

Responsible managers include the Clark Fork License Manager, Sr. Director of Environmental Affairs, and Sr VP Energy Resources & Env Comp Officer along withmany other internal and external stakeholders. Externally, we submit annual work plans and reports to FERC for its review and approval. Many decisions are subject, per the License, to oversight by the Clark Fork Management Committee, consisting of settlement party members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Cabinet Gorge Dam Fishway* 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:	Monica Ott	Date:	10/2/2023
Print Name:	Monica Ott		
Title:	Manager Clark Fork License		
Role:	Business Case Owner		
Signature:	Bruce F. Howard	Date:	10/2/23
Print Name:	Bruce Howard		
Title:	Sr Dir Environmental Affairs		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name: Cabinet Gorge Fishway

2. Business Case Owner: Nate Hall

3. Director Responsible: Bruce Howard

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

Answer: There are no quantifiable direct savings for implementing this compliance element of the Clark Fork Settlement Agreement and License. Construction of the Fishway is required under the Settlement Agreement (see below for additional information).

Quantified direct savings:

2022	2023	Lifetime
NA	NA	NA

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Answer: There are no quantifiable direct savings for implementing this compliance element of the Clark Fork Settlement Agreement and License. Construction of the Fishway is required under the Settlement Agreement (see below for additional information).

Quantified indirect savings:

2022	2023	Lifetime
NA	NA	NA

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

Answer: Please see the form for the Clark Fork Settlement Agreement and License Implementation for additional context. Regarding the Fishway, construction of a permanent fish passage facility is required as part of the Settlement Agreement and Amendments. This facility will also fulfill the reserved mandatory conditioning authority of the U.S. Fish and Wildlife Service under Section 18 of the Federal Power Act. By reaching an agreement regarding fish passage, Avista avoided a mandate from the agency, which was likely a more complex and expensive structure, as well as the risk that such a facility would be subject to ongoing new requirements if it did not perform to the agency's satisfaction. In settlement, we have protected customers from substantial redevelopment risks. This project also fulfills Endangered Species Act requirements for bull trout, a listed species. These agreements last at least the term of the license.

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

Director Name Bruce Howard

Director Signature DocuSigned by: Bruce Howard CDB9B5DDD0114A5...

Date Oct-29-2021 | 10:25 AM PDT

Clark Fork Settlement Agreement

EXECUTIVE SUMMARY

The ongoing operation of the Clark Fork Project is conditioned by the Clark Fork Settlement Agreement (CFSA) and the Federal Energy Regulatory Agency (FERC) License No. 2058. The CFSA and License are the result of a multi-year stakeholder engagement and negotiation process, which established the terms of the 45-year license issued to Avista. Imbedded in the License is the requirement to continue to consult agencies, tribes and other stakeholders. In addition, the CFSA and License provide decision-making participation for the settlement signatories, resulting in ongoing negotiations on implementing license terms. The CFSA and License also include a number of funding commitments to help achieve long-term resource goals in the Clark Fork and related watersheds. Some items are relatively predictable each year; many others are dynamic, depending on potential projects, natural resource conditions and evolving resource management goals. Most projects are implemented with collaborating agencies and Tribes, often with multiple funding sources.

Avista is required to develop an annual implementation plan and report, addressing all Protection, Mitigation and Enhancement (PM&E) measures of the License. Implementation of these measures is intended to address ongoing compliance with Montana and Idaho Clean Water Act requirements, the Endangered Species Act, and state, federal and tribal water quality standards, among other statutory and regulatory requirements. License articles also describe our operational requirements for items such as minimum flows, and reservoir levels, as well as dam safety and public safety requirements, land use, and related matters.

If capital funds were not available for CFSA projects Avista would have to fund them through O&M dollars, or be in breach of an agreement and in violation of its FERC License. There would be risk for administrative orders and penalties, new license requirements, increased mitigation costs, and potential loss of operational flexibility of the Cabinet Gorge and Noxon Rapids Hydro Electric Facilities. Loss of operational flexibility, or of these generation assets, would create substantial new costs, which would be detrimental of all our electric customers. Funding of the Clark Fork License implementation is essential to remain in compliance with the FERC License and CFSA, which provides Avista the operational flexibility to own and operate the Clark Fork hydroelectric facilities. Therefore, if these costs were not capitalized, Avista would continue to implement License articles and all costs would be an operating expense.

VERSION HISTORY

Version	Author	Description	Date
1.0	Monica Ott	*Initial draft of original business case*	*10-2-23*
BCRT	*Heide Evans*	*Has been reviewed by BCRT and meets necessary requirements*	*9-5-23*

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)

2024	**$3,027,379**	**$3,027,379**
2025	**$2,663,700**	**$2,663,700**
2026	**$3,291,711**	**$3,291,711**
2027	**$4,051,463**	**$4,051,463**
2028	**#3,913,007**	**$3,913,007**

Project Life Span	*50 year*
Requesting Organization/Department	B04 / Clark Fork License
Business Case Owner | Sponsor	Monica Ott / Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
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?

Funding of the Clark Fork License Implementation is essential to remain in compliance with the FERC License and the CFSA for permission to continue to own and operate the hydro-electric facilities. This commitment was made in 2001 and is ongoing. At that time, Avista determined that the Settlement was in the best interest of Avista, our customers, our shareholders, and the communities we serve.

1.2 Discuss the major drivers of the business case.

Investment Drivers

The investment driver associated with the CFSA and FERC License fall under Mandatory and Compliance. Benefit to our customers and the company is the ability to provide clean, reliable and cost-effective power.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

If the PM&E activities and license articles are not funded and implemented, we would be in breach of an agreement and in violation of our FERC License. There would be high risk for penalties and fines, new license requirements, higher mitigation costs, and loss of operational flexibility of the Cabinet Gorge and Noxon Rapids Hydro-Electric (HED) Facilities.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization.

Avista Strategic Goals

Remaining in compliance allows for the continued operation of the Clark Fork and Noxon HEDs for the benefit of our customers and company. This supports our commitments to collaboration, environmental stewardship, and trustworthiness – all to help deliver clean, renewable energy for our customers.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

NA

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

We are required by the license to develop, in consultation with the Management Committee, an annual implementation plan and report, addressing all PM&E measures of the License. In addition, implementation of these measures is intended to address ongoing compliance with Montana and Idaho Clean Water Act requirements, the Endangered Species Act (fish passage), and state, federal and tribal water quality standards as applicable. License articles also describe our operational requirements for items such as minimum flows, and reservoir levels, as well as dam safety and public safety requirements.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Primary consideration occurred during the multi-year negotiations that led to the CFSA and License, and all decisions were documented throughout the process. If the PM&Es and license articles are not funded and implemented, Avista would be in breach of an agreement and in violation of our License. There would be high risk for penalties and fines, new license requirements, higher mitigation costs, and loss of operational flexibility of the Cabinet Gorge and Noxon Rapids Hydro Electric Facilities. Loss of operational flexibility, or of these generation assets, would create substantial new costs, which would be detrimental to all our electric customers and the company. Funding of the CFSA is essential to remain in compliance with the FERC license, which provides Avista the operational flexibility to own and operate the hydro-electric facilities in Cabinet Gorge, Idaho and Noxon, Montana.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

There are no quantifiable direct savings calculable, as this Business Case funds implementation of the CFSA, which is contained in and enforceable under the Clark Fork FERC License, for Project #2058.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

There are no quantifiable in-direct savings calculable, as this Business Case funds implementation of the CFSA, which is contained in and enforceable under the Clark Fork FERC License, for Project #2058

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

Funding and implementation of the FERC License and CFSA is necessary to operate the Clark Fork Project. Obligated funding is outlined in the CFSA. The alternative to not funding the CFSA is to be out of compliance with the FERC License. Penalties would include fines, new license requirements, higher mitigation costs and potential loss of operational flexibility.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success from implementation and funding of the CFSA can be demonstrated through continued compliance with regulators (FERC, USFWS, others), continued collaboration with CFSA stakeholders, lack of litigation, and continued operational flexibility for Noxon Rapids and Cabinet Gorge dams. Individual CFSA projects are monitored and

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

quantified from a resource perspective to show project success or progress over time toward meeting the goals of mitigating impacts from the Clark Fork Project.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is an ongoing commitment running with the Clark Fork FERC License #2058 and will continue until the License expires in 2046

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

FERC and over 20 other parties, including the States of Idaho and Montana, various federal agencies, five Native American tribes, and numerous Non-Governmental Organizations. In addition, we coordinate with numerous internal stakeholders, in particular within GPSS and Power Supply.

Responsible managers include the Clark Fork License Manager, Sr. Director of Environmental Affairs, and Sr VP Energy Resources & Env Comp Officer, and many other internal and external stakeholders provide oversite. Externally, we submit annual work plans and reports to FERC for its review and approval. Many decisions are subject, per the License, to oversite by the Clark Fork Management Committee, consisting of settlement parties. And many elements receive oversite from internal staff in GPSS and Power Supply

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Clark Fork Settlement Agreement 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: Monica Ott   Date: 10/2/2023

Print Name: Monica Ott

Title: Clark Fork License Manager

Role: Business Case Owner

Signature: Bruce F. Howard   Date: 10/3/23

Print Name: Bruce F. Howard

Title: Sr. Director, Environmental Affairs

Role: Business Case Sponsor

Clark Fork Settlement Agreement

Signature: ______________________ Date: __________

Print Name: ______________________

Title: ______________________

Role: Steering/Advisory Committee Review

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name: Clark Fork Settlement Agreement

2. Business Case Owner: Nate Hall

3. Director Responsible: Bruce Howard

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

Answer: There are no quantifiable direct savings calculable, as this Business Case funds implementation of the Clark Fork Settlement Agreement, which is contained in and enforceable under the Clark Fork Federal Energy Regulatory Agency (FERC) License, for Project #2058. A license from FERC is required to operate non-federal hydroelectric projects. Avista pioneered what became the Alternative Licensing Process by seeking concurrence of two states, five Tribes, multiple federal, state and local agencies, multiple non-governmental environmental organizations, land owners and other stakeholders. In developing a 27-party agreement, Avista avoided the potential of extensive litigation and license delays, as well as potentially costly applications of mandatory conditions. See below for additional information.

Quantified direct savings:

2022	2023	Lifetime
NA	NA	NA

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Answer: The FERC License achieved as a result of the Clark Fork Settlement Agreement allows significant operational flexibility at Noxon Rapids and Cabinet Gorge dams. The mitigation programs are what allow us, in part, to be able to load follow with these resources. For example, we currently have no ramping rate restrictions and relatively easy to meet flow requirements. Maintaining this operational flexibility was a goal of the relicensing process to ensure reliable energy to follow customer loads. If Avista had to replace this load-following capacity with alternative sources, the additional costs would be in the hundreds of millions.

Quantified indirect savings:

2022	2023	Lifetime
NA	NA	NA

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

Answer: A FERC license is required under the Federal Power Act. That Act, in turn, triggers other federal and state regulatory oversight. These include the Clean Water Act, National Historic Preservation Act, National Environmental Policy Act, and Endangered Species Act. In some instances, federal or state agencies have mandatory conditioning authority. For example, states that have delegated CWA authority issue CWA Section 401 Certification for hydro projects, within which they place conditions. When 401 Certifications are final, FERC has no discretion, but must include such Certifications as license conditions, and licensees such as Avista must comply with these conditions. Another example are conditions referenced under the Federal Power Act in section 4(e), wherein federal land agencies with lands within a FERC project boundary may prescribe mandatory conditions. Other Sections of the Federal Power Act require FERC to consider recommendations from a wide array of state, tribal and federal entities [10(a)], to assign annual charges for occupancy of federal lands [10(e)] and allow the U.S. Fish & Wildlife Service to either prescribe fish passage or reserve the authority to later require it [18(e)]. All these authorities, and more, came in to play in the Clark Fork Settlement Agreement and issuance of the FERC License. Additionally, FERC included numerous license articles.

Avista is required to comply with all terms of the License. Non-compliance would expose Avista to potential enforcement by FERC under its FPA authority, as well as to enforcement by agencies which claim direct enforcement authority under specific statutes, as well as citizen enforcement allowed under statutes such as the CWA. Each authority contains its own provisions on allowed penalties. Additionally, parties to the settlement could petition FERC for enforcement and/or dispute resolution, creating legal costs in addition to penalty amounts. Avista would risk challenges to its operational flexibility on the Clark Fork as well as the lack of flexibility to comply with orders issued by FERC. Ultimately, non-compliance could allow FERC to open a License for a third party to take over. Finally, Avista would suffer reputational risks in not complying with the CFSA and License.

Kettle Falls Ash Landfill Expansion

EXECUTIVE SUMMARY

PROJECT NEED: Kettle Falls Generation Station burns on average of 450,000 green tons of wood waste annually. This combustion process creates roughly 30,000 cubic yards of ash that is trucked and stored at the 177-acre parcel south of the plant site. The landfill area is approximately 15 acres nested inside of a 42-acre fenced parcel designated for landfill operations and development. The current ash landfill is reaching its full capacity and is expected to be completely filled between 2025 to 2028 depending on plant dispatch and ash production.

RECOMMENDED SOLUTION: The proposed solution to construct a new Phase 4 lined landfill built to current standards will incorporate the closure costs of Phase 3 as part of the construction of new disposal area.

ALTERNATIVES CONSIDERED:

- Phase 4 Concept 2A (Selected);
- Phase 4 Concept 1;
- Close Landfill and Dispose at Area Landfill;
- Cancel Project due to Rerate Project

COST OF RECOMMENDED SOLUTION: $10,850,000

ADDITIONAL INFO: The Phase 3 Overlay / Phase 4 landfill is the lowest cost impact to customers for disposal of ash as compared to disposal into the nearest acceptable landfill. Disposal costs would exceed 2 million per year of O&M expense if Phase 4 is not constructed. In addition, there is long-term operational risk if Avista does not control its ash disposal mechanism. If the business case is not funded, it is estimated that the landfill will exhaust its current capacity in 2026 and Avista would have nowhere to dispose of its ash, jeopardizing operation of KFGS.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Greg Wiggins	GPSS_KF_Ash Landfill Expansion	7/9/2020	Reference Master Landfill Plan
1.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
2.0	Greg Crossman	Annual update	5/11/2023	
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	10/2023	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 2,220,000	$ 0
2025	$ 4,820,000	$ 0
2026	$ 3,225,500	$ 10,850,000
2027	$ -	$ -
2028	$ -	$ -

Project Life Span	7 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Patrick Lutskas | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Initiation
Category	Project
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

The Kettle Falls Generation Station is a renewable resource for Avista that uses biomass for its primary fuel source. The combustion process burning wood creates ash in the volume of 30,000 cubic yards annually depending on plant dispatch.

The current ash landfill is reaching its full capacity and is expected to be completely filled between 2025 to 2028 depending on plant dispatch and ash production.

1.2 Discuss the major drivers of the business case

Major drivers to this project include Mandatory & Compliance, Performance & Capacity and Asset Condition. They Phase 3 landfill will require mandatory proper closure following the Department of Ecology guidelines for retiring landfills. Without having a disposal site for the ash, the plant would be forced to close or operate as a natural gas fire unit which would lose 53 MW's of renewable resources from Avista's portfolio. Estimated costs associated to haul the ash to an area landfill exceed 2 million O&M expense annually. By constructing the new expansion operating costs will significantly less.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The landfill is nearing capacity. With permitting, engineering and construction as part of the project, this project to finish construction within the expected life of the current Phase 3 disposal area.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. [Avista Strategic Goals]

Kettle Falls Generating Station is a valuable resource for Avista. The plant generates up to 53 MW's of base loaded renewable power to help meet Avista vision of being 100% carbon neutral and a renewable. This project address addresses the Trustworthy characteristic of our Company's values because properly disposing of the ash is the right thing to do.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Work has been ongoing since 2019 with third party Landfill consultants EIL (Environmental Information Logistics) and Schwyn Environmental. Avista Environmental support and plant staff have been modeling and tracking current fill rates for 20+ years and have data to model the time in which the landfill will reach full capacity. EIL has developed a Master Landfill Plan for the closure of Phase 3 and the development of Phase 4 and ongoing associated operating costs with the new landfill.

Ash has been generated from the plant and stored at the area landfill since 1986 consisting of three engineered cells (Phase 1-3). Phases 1 and 2 were closed and covered in 2003 in accordance with WAC regulations. In February 2020 a permit modification request was submitted with the Department of Ecology to increase the slope of Phase 3 from a 4:1 to a 3:1. This request would increase the capacity of the current Phase 3 by 110,000 cubic yards. On May 5th, 2020, the Department of Ecology approved the request to increase the Phase 3 slope. Calculations with the newly approved slope and existing air space revealed Phase 3 reaching full capacity in 2025.

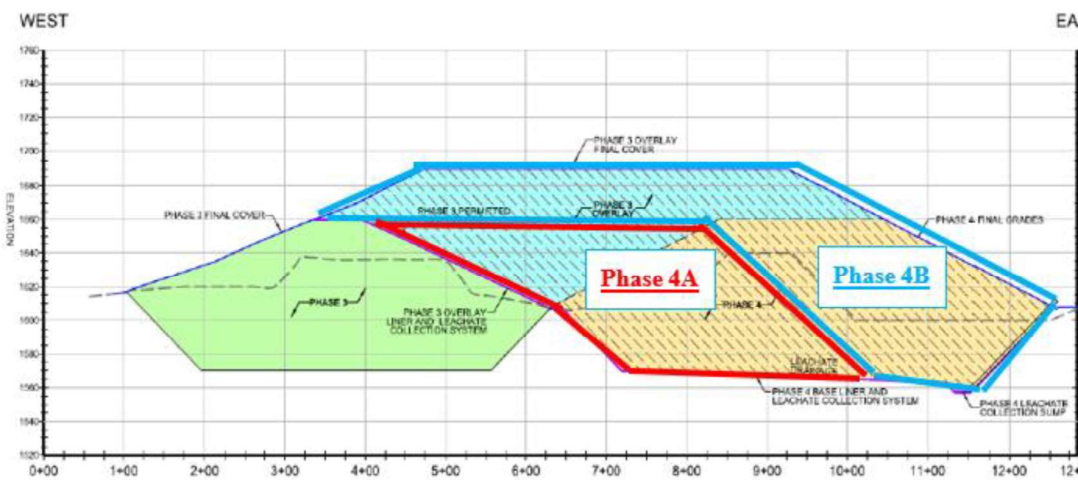
EIL and Schwyn Environmental Services was hired to assist in the planning and budgeting efforts to create a Landfill Master Plan for current operations, closure of Phase 3 and engineering and design of Phase 4. The creation of the new Phase 4 landfill area creates space for ash disposal at the current rate of nearly 40-50 years of disposal.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: The recommended solution is to construct a new Phase 4 lined landfill built to current standards that will incorporate the closure costs of Phase 3 as part of the construction of the new disposal area. Referenced in the Kettle Falls Master Landfill Plan as Concept 2A is to construct Phase 4 utilizing the air space between the two cells. In this option some of the Phase 3 closure costs are absorbed into the additional space created between the two independent cells. The overlay of Phase 3 becomes part of the leachate collection system for Phase 4 and increases total disposal capacity.

This solution is the best value and provides an estimated 40 to 50 years of additional ash disposal capacity to Avista. As compared to Concept 1, this option provides approximately 15 years of additional capacity by utilizing the



SECTION A-A' - CONCEPT 2A - PHASE 3 OVERLAY ON PHASE 3 PERMITTED FINAL GRADES

intermediate space between the existing Phase 3 and future Phase 4 and only minimally increases the project cost to do so. In addition, this option incorporates Phase 3 closure costs, which provides additional value at nearly the same cost as Concept 1.

In Scope: permitting, engineering and construction of new expansion phases, plus new monitoring wells, leachate collection system, and ash handling equipment.

Out of Scope: N/A

Assumptions: Due to new regulations regarding landfill design the proposed solution will be a lined landfill with will generate leachate collected in the bottom of the landfill which will need to be processed.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- EIL Kettle Falls Master Landfill Plan has been completed with input from Avista Environmental Team and Plant historical data.
- Drone data was used to calculate the remaining air space of the current landfill area. That data was used to set a timeline until the current Phase 3 will reach its maximum fill capacity date based on current operating data. With an end date determined and the EIL Master Landfill Plan a schedule of projects have been lined out to meet the need of having area to dispose of the plant ash without disrupting the operations and output of the plant or incurring significant disposal fees to area landfills.
- GPSS Ranking Matrix
- CARS form

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$-	$-	$-	$-	$-
O&M	N/A	$-	$-	$-	$-	$-

Current studies are ongoing on the actual system or process that will be used to process the wastewater which may create an O&M increase. Generally speaking, there are no direct capital or O&M offsets that will result from this project.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$-	$-	$-	$-	$-
O&M	N/A	$-	$-	$-	$-	$-

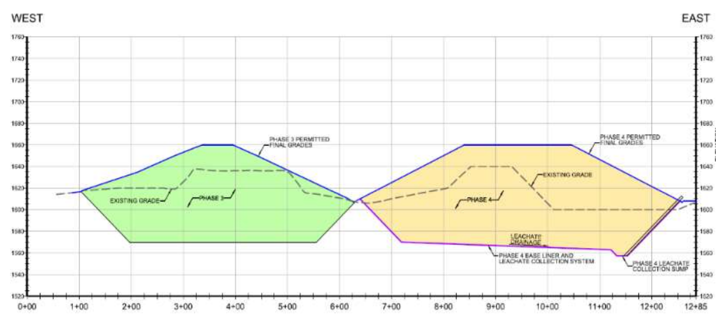
No indirect offsets have been identified associated with this project.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: Construct Phase 4 Concept 2A KF Ash Landfill. The proposed solution will be a lined landfill with will generate leachate collected in the bottom of the landfill which will need to be processed.

Customer

1: Construct Phase 4 Concept 1 KF Ash Landfill; $10M



SECTION A-A' - CONCEPT 1 - STAND ALONE PHASE 4

Concept 1 Phase 4 stand-alone cell located to the east of Phase 3. This design would create and entirely separate landfill which will follow new Limited Purpose Landfill regulations that require an engineered base liner and leachate collection system. Phase 3 shown in green will continue to be in operations as Phase 4 shown in yellow is developed. Phase 3 will be closed after operations shift to Phase 4. As compared to the selected alternative, this alternative provides less capacity and greater overall site impact for almost the same capital investment, so it was not selected.

Alternative 2: Close Phase 3 & begin Hauling Ash to Area Landfill; $2M

This alternative consisted of closure of the Phase 3 landfill area and then disposing ash at an area landfill which would require an increase in O&M expense near 2 million annually. This alternative does not provide a long-term solution to Avista, and instead relies on a third-party being able to accept the ash year after year, which may not be guaranteed. This presents undue risk to

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Avista since its ability to continue operating would be dependent on third-party ash acceptance.

Alternative 3: Cancel Project because of future Kettle Falls Rerate Project; $0 Capital Cost

Alternative 3 remains in consideration pending development of the Rerate project and associated third-party Carbon Reduction Facility construction. The third party developing the CRF is also developing alternate markets for the existing KFGS ash stream that if realized would significantly reduce the volume of ash needing to be disposed of at the landfill. Because this alternative is contingent on a different project, it could not be selected on its own and therefore the next best landfill expansion alternative (Phase 4 Concept 2A) is still being pursued to provide the additional capacity should it be needed. However, in the course of both projects this alternative will continue to be evaluated and will be exercised if and when it is prudent for Avista to do so. As currently defined, this alternative presents significant upside to Avista and in fact reduces cost and risk, however it is not an at-will alternative because of its dependency on other projects and markets.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Work has been ongoing since 2019 with third party Landfill consultants EIL and Schwyn Environmental. Avista Environmental support and plant staff have been modeling and tracking current fill rates for 20+ years and have data to model the time in which the landfill will reach full capacity. EIL has developed a Master Landfill Plan for the closure of Phase 3 and the development of Phase 4 and ongoing associated operating costs with the new landfill.

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known

- **Start Date:** 2021
- **End Date:** 2027

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

<u>Steering Committee/Governance Team</u>

Steering committee will include both GPSS and Environmental Senior Leadership.

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Ash Landfill Expansion 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.

DocuSigned by:

Signature: Lutskas, Patrick Date: Nov-08-2023 | 11:30 AM PST

25101CE4BDFF42B...

Print Name: Patrick Lutskas

Title: Plant Manager

Role: Business Case Owner

DocuSigned by:

Signature: Alexander, Alexis Date: Nov-27-2023 | 4:48 AM PST

EA27BADA767E467...

Print Name: Alexis Alexander

Title: Director, GPSS

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Long Lake Stability Enhancement

EXECUTIVE SUMMARY

PROJECT NEED: The major driver for this business case is regulatory. FERC (Federal Energy Regulatory Commission) requested analysis revealed that Long Lake dam does not meet the internal plane stability minimum safety factor during a PMF (probably maximum flood) event. Avista submitted a preliminary study to the FERC and is waiting for final design before sending the FERC the full scope of the project and timeline to address mitigation. Avista is also revising the Spokane River PMF and performing a site-specific seismic hazard assessment to fully understand the loadings at the facility. The PMF has been recently approved and approval of the seismic loads are anticipated by mid-2023. The results of the detailed 3D modeling of the facility are anticipated to reduce the necessary mitigation efforts to satisfy FERC stability criteria. The FERC expects Avista to develop a mitigation plan to address the stability issues once modeling is complete and therefore this project is mandatory. If this project does not move forward, Avista's relationship with the FERC will be heavily damaged and costly operational changes or even fines will result.

RECOMMENDED SOLUTION: The recommended solution will be heavily informed by the Engineering efforts dating back to 2016, however, recent discoveries have narrowed the remediation efforts to the following Alternatives listed below.

ALTERNATIVES CONSIDERED (as of 2023):
Up to 5 different construction items may be needed for Long Lake Dam based on the ongoing engineering efforts. The path forward includes additional engineering (PCA & FEA of the dam and left abutment), design, FERC approvals, and construction. The expected possible alternatives include:

- Waterstop installation for Long Lake Dam
- Spillway pier repair (strengthening/ the concrete added in 1918 and 1930)
- Spillway pier stabilization (anchoring and/or new deck)
- Left abutment rock wedge stabilization
- Intake dam stabilization (anchors)

ALTERNATIVES CONSIDERED:
A high-level construction feasibility study was conducted prior to embarking on the 3D Finite Element Modeling stage and was refined by a third-party industry expert in dam stability and anchoring, and heavy civil construction Engineering Solutions. It was estimated that the construction could be done in one year but more realistically should be done over two years

- Alternative 1: Initial Anchor Design, Two Season Construction schedule (initial estimate of $18.52M)
- Alternative 2: Initial Anchor Design, One Season Construction schedule (initial estimate of $18.65M)
- Alternative 3: New Design, Anchors, Drains and Grouting (initial estimate of $17.35M)

COST OF RECOMMENDED SOLUTION: Total project costs have an overall estimate at complete cost of $41.6M (2023 estimate).

ADDITIONAL INFO: Not completing the Stability Enhancement Project will place Avista out of compliance with our FERC License Requirements. FERC can require operational changes or additional, costly risk reduction measures, up to and including the loss of power generation at Long Lake. If work is not performed this has cost and operational repercussions which could affect our customers in terms of cost, reliability of energy, and reputational damage. performed this has cost and operational repercussions which could affect our customers in terms of cost, reliability of energy, and reputational damage.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	PJ Henscheid	Format existing BC into exec summary	7.6.20	
2.0	Michael Truex / PJ Henscheid	Completion of full BCJN document	7.31.20	
3.0	PJ Henscheid	Updated to 2022 template and modified budget to align with improved estimates	8.24.22	
4.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
5.0	Wendy Iris/Brandon Little/PJ Henscheid	Updated to reflect current state of project and engineering efforts – revealing some new remediation needs	5/10/2023	
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 1,600,000	0
2025	$ 1,400,000	0
2026	$ 1,000,000	0
2027	$ 12,500,000	$ 20,000,000
2028	$ 16,100,000	$ 21,000,000

Project Life Span	13 years (2016-2028)
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	PJ Henscheid | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

[Investment Drivers]

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

Long Lake dam does not meet the internal plane stability minimum safety factor during a PMF event. Also, Avista believes a large portion of water seepage in the concrete is related to deteriorated water stops installed along the vertical construction joints during the original construction.

1.2 Discuss the major drivers of the business case

The major driver for this business case is Regulatory/ Mandatory & Compliance. Avista is subject to multiple Federal, State and Local environmental regulatory programs. Avista is required by FERC to maintain facilities for generation and public safety. The FERC license for Long Lake HED includes several operational requirements that depend on reliable operation of the generation units as well as the intakes and spill gates.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Not completing the Stability Enhancement Project will place Avista out of compliance with our FERC License Requirements. FERC can require operational changes or additional, costly risk reduction measures, up to and including the loss of power generation at Long Lake.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. Avista Strategic Goals

This project touches upon the value that Avista is trustworthy. Executing this project allows Avista to take care or our assets—assets that are vital to providing our cusomters with reliable energy, safely.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

See Section 2.2

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: ***A final recommendation is pending final engineering design.*** The recommended solution will be heavily informed by the Engineering efforts dating back to 2016, however, recent discoveries have narrowed the remediation efforts to the following Alternatives listed below. ALTERNATIVES CONSIDERED (2023): Up to 5 different construction items may be needed for Long Lake Dam based on the ongoing engineering efforts. The path forward includes additional engineering (Pier Condition Assessment & Finite Element Analysis of the dam and left abutment), design, FERC approvals, and construction. The expected possible alternatives include: Waterstop installation for Long Lake Dam Spillway pier repair (strengthening/ the concrete added in 1918 and 1930) Spillway pier stabilization (anchoring and/or new deck) Left abutment rock wedge stabilization Intake dam stabilization (anchors)

In Scope: A final recommendation is pending final engineering design.

Out of Scope: A final recommendation is pending final engineering design.

Assumptions: A final recommendation is pending final engineering design.

The above alternatives have recently been presented to the project team; however, there is still active engineering work going on to determine the 3D effects of the facility and the seismic requirements at the location. Dam Safety is monitoring movement, uplift pressures, and deflection of the intake and spillway dam. The project team recently completed (February 2023) boring and drilling and is completing laboratory testing to aid the assessment of the structural integrity of the concrete piers. Once those variables are determined, these alternatives will be re-evaluated, and the capital investment costs will be re-analyzed.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- Alden Report
- Avista's Dam Safety Surveillance Plans and Reports
- Finite Element Analysis

- The initial design work, value engineering, and constructability reviews, as well as industry studies, reports, and information gleaned from Avista's peer dam owners have all contributed to the development of the business case.
- Risk Cost calculation from GPSS Asset Management Group: Risk cost is the product of the Failure Rate, Potential Consequence of failure, and the Probability of experiencing the potential consequence in the event of a failure. This risk cost is associated with the probable dollar value associated with Avista's exposure risk of each component. This exposure risk includes the cost of anything that threatens the company, including costs associated with a probable failure of the components (potentially including replacement, refurbishment, or lost generation costs), safety risks associated with normal operation or replacement actions, and probable environmental risks associated with the asset, and at times other costs such as public perception risk mitigation activities. While the company may not be able to shelter itself from risk completely, there are ways it can help protect itself from the effects of business risk, primarily by adopting a risk management strategy as a part of the asset management program. Risk costs not only take account for the exposure risk for an asset but also the criticality (or importance of an asset) and its' current condition. Risk costs are somewhat analogous to insurance premiums. They represent an annual cost, but the year-to-year costs vary with the condition of the assets. If we total the risk costs for all of our assets for the next year, the company would need to have monies set aside for that year to cover the costs associated with the assets that fail that year.

$$\begin{aligned}&\mathit{Annual\ Risk\ Cost}\\&= [\mathit{Probability\ of\ Failure\ (that\ year)}] \times [\mathit{Consequence\ \$}]\\&\times [\mathit{Likelhood\ of\ actually\ experiencing\ that\ consequence}]\end{aligned}$$

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	N/A	$0	$0	$0	$0	$0

Since this project is driven by regulatory efforts there are no known offsets.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

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[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	N/A	$0	$0	$0	$0	$0

Since this project is driven by regulatory efforts there are no known offsets.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: A final recommendation is pending final engineering design. However, the initial design work considers some high level mitigation solutions, including adding post-tension anchors into bedrock, adding pressure relief drains, and adding mass concrete to the dam structure itself. These options, or a combination thereof, can bring the dams into FERC stability compliance.

The recommended solution will be heavily informed by the Engineering efforts dating back to 2016, however, recent discoveries have narrowed the remediation efforts to the following Alternatives listed below. ALTERNATIVES CONSIDERED (2023): Up to 5 different construction items may be needed for Long Lake Dam based on the ongoing engineering efforts. The path forward includes additional engineering (Pier Condition Assessment & Finite Element Analysis of the dam and left abutment), design, FERC approvals, and construction. The expected possible alternatives include: Waterstop installation for Long Lake Dam Spillway pier repair (strengthening/ the concrete added in 1918 and 1930) Spillway pier stabilization (anchoring and/or new deck) Left abutment rock wedge stabilization Intake dam stabilization (anchors)

The above alternatives have recently been presented to the project team; however, there is still active engineering work going on to determine the 3D effects of the facility and the seismic requirements at the location. Dam Safety is monitoring movement, uplift pressures, and deflection of the intake and spillway dam.

The project team recently completed (February 2023) boring and drilling and is completing laboratory testing to aid the assessment of the structural integrity of the concrete piers. Once those variables are determined, these alternatives will be re-evaluated, and the capital investment costs will be re-analyzed.

Alternative 1: Initial Anchor Design, Two Season Construction schedule; $18.52M

This alternative was based upon an initial engineering analysis and therefore required many anchors. It was not selected, with thoughts that a more detailed engineering model would require a reduced number of anchors.

Alternative 2: Initial Anchor Design, One Season Construction schedule; $18.65M

This alternative was based upon an initial engineering analysis and therefore required many anchors. The construction schedule was revised to be one season to attempt to provide savings. It was not selected, with thoughts that a more detailed engineering model would require a reduced number of anchors.

Alternative 3: New Design, Anchors, Drains and Grouting; $17.35M

The engineering efforts are still in process. But those efforts are revealing other stability issues that will need to be addressed. The number of anchors may decrease but there is a possibility that additional work is needed to stabilize the Piers, Spillway, Intake and left abutment. This alternative is not a complete solution therefore not selected.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Initial stability studies revealed that Long Lake dam does not meet FERC stability criteria during PMF and Post-Earthquake loading conditions. Success of the project requires design and delivery of stability measures to bring the spillway and intake dams into compliance with FERC stability requirements. Stability measures justified through a value engineering analysis, satisfying FERC factors of safety for stability, and properly constructed per plans and specification would be considered a success.

The initial design work considers some high-level mitigation solutions, including adding post-tension anchors into bedrock, adding pressure relief drains, and adding mass concrete to the dam structure itself. These options, or a combination thereof, can bring the dams into FERC stability compliance. No other solutions are known to exist for stabilizing the dam.

Finalizing the design parameters and establishing a more defined budget will be essential in the success of project delivery and capital budget forecasting. To assist in delivering the project on time and within our budget parameters, we will be looking for an alternative progressive project delivery method.

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known

- **Start Date:** 2016
- **End Date:** 2028

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

<u>Steering Committee/Governance Team</u>

- Jacob Reidt – Sr Manager Project Delivery
- Greg Wiggins – Sr Manager of Hydro Ops & Maintenance
- Meghan Lunney – Spokane River License Manager

<u>Oversight Process</u>

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Long Lake Stability Enhancement business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 11:06 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alexis Alexander EA27BABA767F467...	Date:	Aug-26-2023 | 1:34 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

Signature:	NA	Date:	
Print Name:	NA; Alexis Alexander is on the steering committee for this project.		
Title:	NA		
Role:	Steering/Advisory Committee Review		

GPSS_Operational Safety and Compliance

EXECUTIVE SUMMARY

The diverse Avista-owned generating facilities include Hydro, Biomass, and Natural Gas fuel power producing resources. The assets range in age, condition, output, and configuration. Together these facilities bring a balanced approach to meeting our electric customers needs throughout the year. The 13 Avista-owned generating facilities have a total capacity of nearly 1.6GW of electricity. These facilities include 8 hydroelectric dams located on the Clark Fork and Spokane Rivers, a stand-alone biomass facility located in Kettle Falls, Washington, and four natural gas generating plants spread between in Idaho, Washington, and Oregon.

This program will support the various compliance and safety related projects within all of the Avista-owned generating facilities. The projects are intended to address compliance and/or safety related matters at the facilities. Projects will be level 0 to level 1 in project complexity and coordination. . This program is critical in supporting facility compliance with agencies including NERC, FERC, WEC and OSHA. Identified projects will be governed by the Plant Manager, Operations Engineering Manager, and Senior Operations & Maintenance Manager.

The GPSS Operations team will coordinate and manage a 5 year plan of identified projects to sustain the safe and reliable operations of the Avista-owned generation assets. The annual budget will vary and depends on evaluation of asset conditionto meet the mandate requirements identified.

This project will impact customers in service code Electric Direct jurisdiction Allocated North serving our electric customers in Washington and Idaho.

VERSION HISTORY

Version	Author	Description	Date
1.0		*Initial draft of original business case*	
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	6,000,000	6,000,000
2025	6,000,000	6,000,000
2026	8,000,000	8,000,000
2027	8,000,000	8,000,000
2028	10,000,000	10,000,000

Project Life Span	*5 years*
Requesting Organization/Department	A07 / Generation Production Substation Support
Business Case Owner | Sponsor	Greg Wiggins / Alexis Alexander |
Sponsor Organization/Department	Alexis Alexander / GPSS
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

This program will support the compliance and safety related projects within all of the Avista-owned generating facilities. The projects are necessary to ensure employee safety and/or mandated to meet compliance and safety standards at the facilities. The projects will be planned and scheduled work. The driver will primarily be mandatory and compliance, but may vary between individual projects.

Currently there are four similar GPSS programs which include the Base Load Hydro, Base Load Thermal, Regulating Hydro, and Peaking Thermal programs used to fund a multitude of level 0 and level 1 projects. Although the projects are justified the segmented programs create inconsistency in the investment strategy and approach. The combination of the Thermal and Hydro Operations teams will better enable consistent asset management forecasting and prioritization across the entire generation fleet. A single prioritization ranking methodology, and governance structure will improve the effective deployment of resources.

1.2 Discuss the major drivers of the business case.

Mandatory and Compliance – Investments are driven by compliance with laws, rules, and contractual obligations.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The Avista-owned hydro and thermal generating facilities have a wide range of regulated requirements to ensure operational compliance is met. This program will support the ongoing compliance and safety related projects spread across the 13 facilities. Examples of these projects include: Noxon Spillgate Remediation, Kettle Falls Landfill enhancements, and the Long Lake Stability project. Projects stem from the FERC Dam Safety Program, the Spokane River and Clark Fork River License, and many other regulating agencies, stakeholders, and constituents.

Without this funding source the facilities will lack a minimum project funding to maintain operational compliance

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's core business by delivering energy safely, responsibly, and affordably to our customers. Through prudent investments in plant operations we can ensure the generating facilities are reliable and available to respond to the energy market of the future. In addition, many of the investments improve the operational safety of our employees, enabling them to achieve their optimal performance.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

This program will support 13 Avista-owned generating facilities and will fund a number of projects annually. These projects will vary in size and scope and will be governed by the GPSS Operations team including the Plant Managers, Operations Engineering Manager, and the Senior Operations and Maintenance Manager. With the consolidation of hydro and thermal operations, projects will be analyzed, planned, and executed by one group aligning investment decisions for optimal operational performance. Oprerations and Engineering will work together to create supporting documentation jusityfing the investment for each approved project, utilizing existing asset management analysis and maintenance records.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The Operational Safety and Compliance business case is part of a transition from the Regulating Hydro, Base Load Hydro, Base Load Thermal, and the Peaking Thermal business cases. The previous business cases were intended to ensure a balanced approach in investments made in each of the four operational categories. The combination of renewable integration, unprecedented weather patterns, and new energy policy, has changed Avista's resource mix. As a result, the investments necessary to sustain the operation and maintain our facitlies has taken on a new forecasting profile.

The new program, accompanied by an enhanced resource strategy, including the development of plant and regional project teams, will enable better coordinated project delivery for the respective plants. In addition, a centeralized list of projects across Avista's entire generation fleet will be maintained and prioritized. This is essential, as we modify how we dispatch our fleet, balancing affordability and reliability in the rapidly evolvling energy markets.

Past asset management, maintenance, and investment strategies have changed to meet the new demands. The new resource strategy along with the business case program structure will support improved project planning, execution, and the adaptability needed to respond to unplanned events.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Historical data and analysis on the past Regulating, Base Load, Peaking thermal and hydro projects were used to determine expected budget spend amounts for the future. Projects will follow the GPSS risk based investment planning methodology for life cycle analysis, cost benefit and risk reduction. This work will be done by the GPSS Operations Engineering Team. The major component projects will have an average lifecycle look with current asset condition. The first year Risk Cost Reduction will be projected which is the difference between the current risk costs, based on failure rates, and the risk costs of a new assets. This is analogous to; if Avista were to pay an "insurance premium" to pay for probable consequences of failure.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

DIRECT offsets will be determined for each project, when applicable. This information will be calculated and documented in each project file.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

INDIRECT offsets will be determined for each project, when applicable. This information will be calculated and documented in each project file.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: N/A

Alternative 2: N/A

Alternative 3: N/A

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Where applicable, each project will document alternatives that were considered during the research and planning phase. The alternatives for projects will be determined such as direct replacement, manufactures recommendations and industrial standards.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Projects will be tracked and managed in Maximo asset management program. Historical asset data may be used to compare the project benefits. When available, the data will be used to support the investment decision.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Projects will commence and complete throughout the year over the various plant locations. This process will allow “shovel ready” projects to be quickly put into the queue and executed when funds and resources are available.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Projects will be classified into level 0 and level 1 based on complexity and required coordination. Level 0 projects will utilize the GPSS Operations team consisting of the Plant Manager, Operations Engineering Manager, and Senior Operations and Maintenance Manager for project governance. Projects will be ranked using the GPSS project ranking matrix which focus on various categories including; Personnel and Public Safety, Environmental, Risk of Equipment Failure, Regulatory Mandate, Maintenance Issues, Customer Value, Operating Efficiencies, Operating Costs, and Obsolete Equipment. Level 0 projects are smaller in scope, generally less than $1M, and completed within the calendar year.

Level 1 projects, are larger in scope, schedule, and budget, costing between $1M-$10M and are completed over the course of two years. Level 1 projects will receive a higher level of scrutiny, utilizing the GPSS strategic asset management plan to guide capital replacement strategies. Where data is available, the GPSS risk based investment planning tool will be used to rank asset condition, criticality, and risk costs for level 1 projects.

A dedicated GPSS Program Manager will be responsible for monitoring the program and the associated projects to ensure expected budget and transfer to plant are on target.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the GPSS_Operational Sustainment 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.

DocuSigned by:

Signature: Greg Wiggins
A2CE32875CC64F9...
Date: Aug-11-2023 | 8:32 AM PDT

Print Name: Greg Wiggins

Title: Senior Ops & Maint Manager

Role: Business Case Owner

DocuSigned by:

Signature: Alexis Alexander
EA27BABA767F467...
Date: Aug-26-2023 | 1:32 AM PDT

Print Name: Alexis Alexander

Title: Alexis Alexander

Role: Business Case Sponsor

Signature: ________ Date: ________

Print Name:

Title:

Role: Steering/Advisory Committee Review

Right-of-Way Use Permits

EXECUTIVE SUMMARY

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. Traditionally, we have secured long-term rights-of-way permits for these facilities, but have been required to renew them through an annual billing process. The cost of renewing these permits continues to increase each year, ranging from 3% to 10% annually, depending on the agency/entity, thereby increasing annual O&M expenses to the company and our customers. This business case proposal is to secure long-term agreements with lump-sum payments to reduce overall expenses related to labor of tracking, researching, and processing these annual permits. In some cases, we have been able to negotiate a lower annualized cost over the term of the permit by paying a lump sum up front. In either case, we reduce costs to the company and our customers. Making long-term lump sum payments allows us to capitalize these costs, as the permit is a long-term asset.

A final determination was made by project accounting that all right of way permits may be capitalized since they are in the retirement catalog. The permit must be for a term of at least one year.

Without capital funding, we will continue to incur increasing annual permitting fees and related internal costs as an O&M expense. These costs affect all customers, electric and gas, in the entire Avista service territory.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Ted Hermann*	*Initial draft of original business case*	*8/30/23*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	

Right-of-Way Use Permits

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$250,000**	**$250,000**
2025	**$250,000**	**$250,000**
2026	**$250,000**	**$250,000**
2027	**$250,000**	**$250,000**
2028	**$250,000**	**$250,000**

Project Life Span	***1 Year***
Requesting Organization/Department	V08 / Real Estate
Business Case Owner | Sponsor	Ted Hermann / Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

[Investment Drivers]

Right-of-Way Use Permits

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. As these rights of way permits renew, we've been paying annually increasing fees, leading to increased O&M expenses associated with both the permit costs and the labor to process them.

1.2 Discuss the major drivers of the business case.

This business case is directly tied to Reliability, Mandatory & Compliance, Performance & Capacity, and Failed Plant & Operations. In order to legally construct, maintain and upgrade our facilities on agency owned lands, we must acquire and renew rights of way permits. While we would continue doing this work without this business case, the main benefits to the customer are being able to negotiate lower fixed permit costs through lump sum payments, as well as securing long term permits which will allow us to maintain reliability in our infrastructure. In addition, we will reduce our labor costs for managing these permits. We also reduce the risk of annual permits not being renewed or being modified unilaterally.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Right of way permitting on agency-owned lands is an ongoing and necessary scope of work. We will continue doing this work without an approved capital business case. This business case is based on our potential of saving the company and our customers money over the long term by capitalizing permit fees and negotiating lower costs through long term, lump sum payments.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives, and mission statement of the organization. *See link*.

Avista Strategic Goals

Our proposed investment is aligned with Avista's mission of delivering reliable power to our customers at the most affordable price we can deliver. Right-of-Way Use Permits are required for Avista to construct, maintain, and upgrade electric infrastructure. Without these rights of way, we cannot meet our objectives.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

NA

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

We propose that through this business case, we will work with agencies to negotiate lump sum payments for our rights of way permits, thereby securing long-term, and lower fixed costs associated with acquiring and renewing these permits.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

This business case was developed utilizing a historical analysis of expenses related to labor and other administrative costs in completing previous Right-of-Way Use Permits.

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

There are no quantifiable direct savings, in that this Business Case is for the direct costs of acquiring legal rights to maintain and/or extend rights-of-way (ROW) for Avista's electric transmission/distribution and gas infrastructure on public lands. Public land entities typically provide rights-of-way via permits, and our goal is to acquire these at the lowest cost and for the longest term possible.

Absent such permits, Avista would be required to re-route linear projects around public lands. Such re-routing would result in significant additional direct costs. These would include additional materials and construction costs for longer distances, increased ROW acquisition costs, and increased internal labor for design, planning, permitting and project management. The range of such costs is too uncertain to quantify but would be in the millions of dollars. By not maintaining ROW permit approvals, Avista would risk legal action, fines and ultimately, eviction from public lands.

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

While there are no quantifiable indirect savings, were Avista unable to acquire permits for public land ROW, we would be forced to seek alternative routes. In addition to the direct additional costs, there would be indirect costs, such as increased line losses due to increased distances, increased AFUDC, time delays, etc.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

There are no alternatives to renewing Right-of-Way Use Permits.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Once the highway audit is complete Real Estate will have a complete understanding of what portions of highway have Avista facilities that are not permitted. We can use this audit to track permit application submittals and approvals as we progress through the list. This list is currently maintained in

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Excel. A regular audit should be scheduled every 2 years to verify checks and balances are accurate and facilities are maintained in an approved status.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This is a program, and the work is completed throughout the year based on when agency permits are received. They will become used and useful once the fully executed permit is in place.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

This program will be monitored by the Real Estate Manager, Sr. Director of Environmental Affairs, and Department Financial & Budget Specialist. We will evaluate the annual costs and savings to ensure the program is on track.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Right-of-Way Use Permits* 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:	Theodore W. Hermann	Date:	October 2nd, 2023
Print Name:	Theodore Hermann		
Title:	Manager Real Estate		
Role:	Business Case Owner		

Signature:	Bruce F. Howard	Date:	10/2/23
Print Name:	Bruce Howard		
Title:	Sr Dir Environmental Affairs		
Role:	Business Case Sponsor		

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

Spokane River License Implementation

EXECUTIVE SUMMARY

Non-federal hydroelectric facilities must have a license from the Federal Energy Regulatory Commission (FERC) to operate. Avista's first Spokane River Project License expired in 2007, and after a multi-year process involving hundreds of stakeholders, FERC issued Avista a new 50-year license for the continued operation and maintenance of the Spokane River Project (No. 2545, effective June 18, 2009). This license covers the Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake Hydroelectric Developments. This license defines how Avista shall operate the Spokane River Project and includes several hundred requirements, through license conditions, that we must meet. The license was issued pursuant to the Federal Power Act (FPA) and embodies the requirements of a wide range of other laws (The Clean Water Act, The Endangered Species Act, The National Historic Preservation Act, etc.). These requirements are expressed through specific license articles relating to fish, terrestrial, water quality, recreation, land use, education, cultural and aesthetic resources. Avista also entered into additional two-party agreements with local, state, and federal agencies and the Coeur d'Alene and Spokane Tribes. Avista's FERC license and agreements include mandatory conditions issued by the Idaho Department of Environmental Quality (401 Water Quality Certification, issued June 5, 2008), the Washington Department of Ecology (401 Water Quality Certification, issued May 8, 2009), the U.S. Forest Service (Federal Power Act 4(e), issued May 4, 2007), and the U.S. Department of Interior on behalf of the Coeur d'Alene Tribe (Federal Power Act 4(e), filed January 27, 2009). The FERC license ensures Avista's ability to operate the Spokane River project on behalf of our electric customers within our service territory for a 50-year license term with an annual cost that varies annually.

Complying with our license is mandatory to continued permission to operate the Spokane River Project and funding the implementation activities is essential to remain in compliance with the FERC license. Specific elements of this program change from year to year, depending on license requirements as well as resource conditions. Ongoing stakeholder engagement, and therefore, negotiation, is also required by the license. As a result, some elements of the license are relatively predictable and static while others are dynamic and evolving.

Now that the license has been issued for a term of 50-years, governance is multi-faceted and includes the Spokane River License team engaging with regulatory agencies, external and internal stakeholders in annual, five-year, and ten-year planning to implement the license and settlement agreement conditions. Implementation measures for each of the natural resource conditions have specific success criteria identified. This data along with key accomplishments are reported/documented as part of the license conditions, along with agency/stakeholder approvals. Internal governance can include steering committees for specific major projects, as well as the organizational hierarchy within which the Spokane River team operates. Work coordination occurs through multi-departmental meetings and work planning.

If this business case is not approved, Avista will continue compliance with the FERC license and all costs would be Operating expenses.

VERSION HISTORY

Version	Author	Description	Date
1.0		*Initial draft of original business case*	
BCRT	*BCRT Team Memember*	*Has been reviewed by BCRT and meets necessary requirements*	

Spokane River License Implementation

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$838,800	$838,800
2025	$954,600	$954,600
2026	$908,000	$908,000
2027	$794,800	$794,800
2028	$522,200	$522,200

Project Life Span	*1 year, 5 years, 10 years, etc.*
Requesting Organization/Department	Spokane River License Implementation / C04
Business Case Owner | Sponsor	Meghan Lunney / Bruce Howard
Sponsor Organization/Department	Environmental Affairs / C04
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

Non-federal hydroelectric facilities must have a license from the Federal Energy Regulatory Commission (FERC) to operate. Avista's first Spokane River Project License expired in 2007, and after a multi-year process involving hundreds of stakeholders, FERC issued Avista a new 50-year license for the continued operation and maintenance of the Spokane River Project (No. 2545, effective June 18, 2009). This license covers the Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake Hydroelectric Developments. This license, based in large part on settlement agreements, defines how Avista shall operate the Spokane River Project and includes several hundred requirements, expressed as license conditions, that we must meet. The license was issued pursuant to the Federal Power Act (FPA) and embodies the requirements of a wide range of other laws (The Clean Water Act, The Endangered Species Act, The National Historic Preservation Act, etc.). These requirements are expressed through specific license articles relating to fish, terrestrial, water quality, recreation, land use, education, cultural and aesthetic resources. Avista also entered into additional two-party agreements with local, state, and federal agencies and the Coeur d'Alene and Spokane Tribes, most of which are embodied in the License. Avista's FERC license and agreements include mandatory conditions issued by the Idaho Department of Environmental Quality (401 Water Quality Certification, issued June 5, 2008), the Washington Department of Ecology (401 Water Quality Certification, issued May 8, 2009), the U.S. Forest

Service (Federal Power Act 4(e), issued May 4, 2007), and the U.S. Department of Interior on behalf of the Coeur d'Alene Tribe (Federal Power Act 4(e), filed January 27, 2009). The FERC license ensures Avista's ability to operate the Spokane River project on behalf of our electric customers within our service territory for a 50-year license term. The capital costs of implementing the License varies each year, depending on specific requirements and opportunities to accomplish projects.

1.2 Discuss the major drivers of the business case.

Complying with our license is mandatory for continued permission to operate the Spokane River Project. Funding implementation activities is essential to remain in compliance with the FERC license. Specific elements of this program change from year to year, depending on license requirements as well as resource conditions. Ongoing stakeholder engagement, and therefore, negotiation, is also required by the license. As a result, some elements of the license are relatively predictable and static while others are dynamic and evolving.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Complying with our license is mandatory to continued permission to operate the Spokane River Project and funding the implementation activities is essential to remain in compliance with the FERC license. Ultimately, FERC has the authority to issue orders and penalties, or in the extreme, revoke our license, if we do not comply with the terms and conditions required by it. Loss of operational flexibility, or in the extreme, loss of our generation assets, would create substantial new costs to our customers and no benefits. In addition, Avista would suffer reputational costs for not meeting our commitments.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Implementing the required Spokane River license conditions during 2024 is required by the FERC license in order to operate the Spokane River Hydroelectric Project. This ensures a reliable energy supply for our customers. The License is the result of seven years of community-based collaboration, and implementation also reflects ongoing collaboration with key stakeholders. Additionally, these implementation measures showcase Avista's ongoing commitment to environmental stewardship which benefits our customers, the company and the communities we serve.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Federal Energy Regulatory Commission (FERC). 2009. Order Issuing New License and Approving Annual Charges For Use Of Reservation Lands. Issued June 18.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Avista. 2005. Spokane River Hydroelectric Project, FERC No. 2545, Final Application for New License Major Project – Existing Dam. July 2005.

Avista. 2005. Post Falls Hydroelectric Project, Currently Part of Project No. 2545, Final Application for New License Major Project – Existing Dam. July 2005.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Complying with our license is mandatory to continued permission to operate the Spokane River Project. Funding the implementation activities for the Spokane River Project License is essential to remain in compliance with the FERC license. There are no practicable alternatives to meet compliance. Avista evaluated the potential of surrendering the Spokane River license at the beginning of the relicensing process, determining that this option would be detrimental to our customers, the company and the communities we serve.

If the PM&Es, license articles and settlement agreements are not implemented and/or funded, we would be out of compliance and/or in violation of our License. This would lead to penalties and fines, new license requirements, court costs, higher mitigation costs, and loss of operational flexibility. Ultimately, FERC has the authority to revoke our License if we do not comply with the terms and conditions required by it. Loss of operational flexibility, or in the extreme, loss of our generation assets, would create substantial new costs to our customers and no benefits.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Avista is required to comply with all terms of the License. Non-compliance would expose Avista to potential enforcement by FERC ynder its FPA authority, as well as the enforcement by agencies which claim direct enforcement authority under specific statutes, as well as citizen anforcement allowed under statutes such as the CWA. Each authority contains its own provisions on allowed penalties. Additionally parties to the settlement could petition FERC for enforcement and/or dispute resolution, creating legal costs in addition to penalty amounts. Avista would risk challenges to its operational flexibility as the lack of flexibility to comply with orders issued by FERC. Ultimately, non-compliance could allow FERC to open a License for a third party to take over. Finally, Avista would suffer reputational risks in not complying with the License and its attendant agreements.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

Spokane River License Implementation

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no quantifiable direct savings calculable, as this Business Case funds implementation of the Spokane River Federal Energy Regulatory Agency (FERC) License, for Project #2545. A license from FERC is required to operate non-federal hydroelectric projects. Avista underwent a 7-year relicensing effort from 2002-2009 involving two states, several Tribes, multiple federal, state and local agencies, multiple non-governmental environmental organizations, land owners and other stakeholders. This resulted in a new 50-year license through which Avista avoided the potential of extensive litigation and license delays, as well as potentially costly applications of mandatory conditions.

2.4 Summarize in the table, and describe below the INDIRECT offsets4 (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

As a result of the relicensing process, the FERC License maintained operational flexibility with a minimum of restraints. Maintaining this operational flexibility was one goal of the relicensing process to ensure reliable energy to follow customer loads. Replacing lost generation capacity would require the development of new and more expensive resources with the capability of reliably meeting load.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1:

There are no practicable alternatives to meeting compliance. Avista evaluated the potential of surrendering the Spokane River license at the beginning of the relicensing process, determining

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

that this option would be detrimental to our customers, the company and the communities we serve.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Implementation measures conducted under this capital request are based upon regular meetings engaging with regulatory agencies and external and internal stakeholders during annual, five-year, and ten-year planning meetings. Implementation measures for each of the natural resource conditions have specific success criteria identified. This data along with key accomplishments are reported/documented as part of the license conditions, along with agency/stakeholder approvals. At every opportunity during project planning cost sharing options and opportunities are fully explored to ensure Avista's fiduciary duty to its customers is upheld.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

The requested capital costs will be implemented in accordance with the schedules, milestones and benchmarks identified in the annual planning process as identified and committed to within annual, five-year and ten-year workplans. The work is completed in collaboration with internal and external stakeholders

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

The majority of our external agency stakeholders that interface with this business case include the Idaho Department of Environmental Quality, Idaho Department of Fish and Game, Idaho State Historic Preservation Office, Idaho Department of Lands, Washington Department of Ecology, Washington Department of Fish and Wildlife, Washington State Historic Preservation Office, Washington Department of Natural Resources, U.S. Forest Service, U.S. Fish and Wildlife Service, U.S. Department of Interior, Coeur d'Alene Tribe, and Spokane Tribe. Additional external stakeholders including conservation districts, non-profits, and local educational institutions, as well as a number on non-governmental environmental organizations.

Major internal stakeholders include GPSS, Power Supply, External Communications, etc.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *<Business Case Name>* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	9/29/23
Print Name:	Meghan Lunney		
Title:	Spokane River Manager		
Role:	Business Case Owner		

Signature:	Bruce F. Howard	Date:	10/2/23
Print Name:	Bruce Howard		
Title:	Sr Dir Environmental Affiars		
Role:	Business Case Sponsor		

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

WSDOT Franchises

EXECUTIVE SUMMARY

This program will renew expired franchises for Avista facilities located within Washington State highway rights of way. In accordance with Washington Administrative Code (WAC) 468-34 and Revised Code of Washington (RCW) 47.44, Avista enters into 25-year agreements with the Washington State Department of Transportation (WSDOT) to permit Avista to construct, operate and maintain electric and gas facilities within Washington highway rights of way. These agreements are referred to as franchises. WSDOT manages franchises by reaches of a state highway within a county. Avista has 35 such franchises, 29 of which are expired. Franchise applications cannot be submitted without a completed "Control Zone" analysis and mitigation plan for every above-ground object within the highway right of way and are reviewed by the surveyor, drafting and real estate before submission.

WSDOT requires compliance with control zones prior to franchise renewal. By not having these franchises completed, as well as control zone mitigation approved, Avista is at risk of not being allowed to conduct utility work within the WSDOT right of way. This would expose Avista to potential third-party claims and other costs associated with project delays. Idaho customers could be impacted and benefit from this program, as Avista's transmission facilities which cross state lines are also located in the WSDOT right of way. While we work with internal business units to relocate to private lands via an easement when advantageous, it would take many years and a considerably higher amount of funding to purchase hundreds of miles of easements from private landowners. WAC 47.32.130 gives jurisdiction to WSDOT to enforce control zone guidelines. WSDOT's Utilities Manual M 22-87.07 defines the objectives, general practices, policies and procedures in the design, administration, and coordination of utility franchises within state right of way and properties impacted by above ground objects.

This business case funds the preparation of franchise renewals and control zone mitigation plans, as well as DOT charges associated with these franchise renewals.

VERSION HISTORY

Version	Author	Description	Date
1.0	*Ted Hermann*	*Initial draft of original business case*	*8/17/23*
BCRT	*Heide Evans*	*Has been reviewed by BCRT and meets necessary requirements*	*9/5/23*

WSDOT Franchises

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	**$150,000**	**$150,000**
2025	**$150,000**	**$150,000**
2026	**$150,000**	**$150,000**
2027	**$150,000**	**$150,000**
2028	**$150,000**	**$150,000**

Project Life Span	*1 Year*
Requesting Organization/Department	V08 / Real Estate
Business Case Owner | Sponsor	Ted Hermann / Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

WSDOT Franchises

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

Avista has 35 franchises with WSDOT. These franchises expire at different intervals and are required for Avista to construct, maintain, and upgrade facilities located within the WSDOT right of way. In order to renew or consolidate these franchises, Avista owned facilities and above ground objects must be moved or mitigated. This program addresses the survey, drafting and permitting work in support of the mitigation efforts to be carried out through electric operations plans in the future.

1.2 Discuss the major drivers of the business case.

This business case supports drivers related to Customer Service, Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition and Failed Plant & Operations. In order to continue delivering reliable, low-cost power to our customers, we must be able to construct, maintain and upgrade our electric facilities in the WSDOT right of way. Without approved franchises, Avista would be required to remove facilities from the right-of-way and relocate them on private property.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

This is an ongoing program and has been in effect for several years. If we do not continue doing this work, Avista operations will not be able to effectively build and maintain our electric facilities located within the WSDOT right of way. The risks of not doing this work would require Avista to purchase easements on private property and would be cost prohibitive.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives, and mission statement of the organization. *See link*.

Avista Strategic Goals

Our proposed investment is aligned with Avista's mission of delivering reliable power to our customers at the most affordable price we can deliver. Franchises are required for Avista to construct, maintain, and upgrade electric infrastructure in WSDOT right of way. Without these rights of way, Avista would be forced to purchase easements on private property in order to meet our objectives.

WSDOT Franchises

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

Please see the WSDOT Control Zone Mitigation analysis and plan located in the Business Case Team's site.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

This work is mandatory under state law. To not renew our franchises would greatly impact Avista's ability to serve our customers.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

This business case was developed utilizing a historical analysis of expenses related to labor and other administrative costs in completing previous franchises.

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

There are no quantifiable direct savings, in that this Business Case is for the direct costs of acquiring legal rights to maintain and/or extend rights-of-way (ROW) for Avista's electric transmission/distribution and gas infrastructure on public highways, through franchises with the State of Washington. We are

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

required to have Franchises for each highway by county, issued by WSDOT, and our goal is to acquire these at the lowest cost and for the longest term possible. Absent these, Avista is exposed to delays or denials to conduct construction and maintenance, as well as 3rd-party claims. In addition, Avista could be required to move all infrastructure from highway locations.

Highway ROW Franchises require surveys, submittals, fees and payments to WSDOT for its labor in reviewing the applications. Were we unable to update and maintain highway franchises, Avista could be forced to move this linear infrastructure onto private lands adjoining the highway. Such moves would result in millions of dollars in relocation costs and private ROW acquisition costs. Using the highway ROW for utility infrastructure benefits customers by reducing costs compared to the next best alternative.

2.4 Summarize in the table and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

While there are no quantifiable indirect savings, were Avista unable to secure highway franchises, we would be forced to seek alternative routes. In addition to the direct additional costs, there would be indirect costs, including the opportunity costs of having to prioritize road moves over other work with no benefit to reliability, the potential for increased permitting and restoration costs by having to move away from road rights-of-way, and the costs for potential legal challenges for the need to use eminent domain.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

There are no alternatives to renewing WSDOT franchises. This is a mandatory requirement under WAC 468-34 and RCW 47.44.

Any objects within the highway right of way not covered by a permit or franchise are a misdemeanor. Each object could be considered a separate violation. Each day of violation is a separate and distinct violation. Upon notice by the state, Avista could be liable for a civil penalty of $100 per day per violation beginning 45 days after notification from the state and continuing until application for franchise has been accepted by the state. If a franchise is

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

not applied for within 45 days of notification, the state will require removal of all facilities in highway right of way at utility expense.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

This business case is directly related to the WSDOT Control Zone Mitigation business case. This work must be completed before they can implement actual mitigation plans.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

This program has been in effect for several years. We estimate that due to WSDOT related constraints, it will take approximately ten years to complete all franchises. Each franchise can become used and useful once the franchise is fully executed with the state.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

While not under direct supervision of the WSDOT Control Zone Mitigation Steering Committee, we will work directly with that group to coordinate plans and efforts. This program has oversight from the Real Estate Manager, Sr. Director of Environmental Affairs, and Financial Planning & Analysis Analyst.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *WSDOT Franchises* 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: Theodore W. Hermann Date: 9-18-23
Print Name: Ted Hermann
Title: Real Estate Manager
Role: Business Case Owner

Signature: Bruce F. Howard Date: 9/18/2023
Print Name: Bruce F. Howard
Title: Sr. Director, Environmental Affairs
Role: Business Case Sponsor

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

GPSS_Asset Lifecycle Management

EXECUTIVE SUMMARY

The diverse Avista-owned generating facilities include Hydro, Biomass, and Natural Gas fuel power producing resources. The assets range in age, condition, output, and configuration. Together these facilities bring a balanced approach to meeting our electric customers needs throughout the year. The 13 Avista-owned generating facilities have a total capacity of nearly 1.6GW of electricity. These facilities include 8 hydroelectric dams located on the Clark Fork and Spokane Rivers, a stand-alone biomass facility located in Kettle Falls, Washington, and four natural gas generating plants spread between in Idaho, Washington, and Oregon.

This program will support the various plant projects within all of the Avista-owned generating facilities. These projects are routine and time-based projects intended to extend the life of a system or an asset. They are not intended to replace the full system but instead bring the system back to its original performance and objective. Projects will be level 0 to level 1 in project complexity and coordination. This program is critical in continuing to support asset management program lifecycle replacement schedules. Identified projects will be governed by the Plant Manager, Operations Engineering Manager, and Senior Operations & Maintenance Manager.

The GPSS Operations team will coordinate and manage a 5 year plan of identified projects needed to sustain the safe, reliable, affordable operations of the Avista-owned generation assets. The annual cost of this program is variable and depends on evaluation of asset condition.

This project will impact customers in service code Electric Direct jurisdiction Allocated North serving our electric customers in Washington and Idaho.

VERSION HISTORY

Version	Author	Description	Date
1.0		*Initial draft of original business case*	
1.1	*Glen Farmer*	*Asset Management & Compliance Engineering Review*	*4/27/2023*
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	2,000,000	2,000,000
2025	2,000,000	2,000,000
2026	2,000,000	2,000,000
2027	3,000,000	3,000,000
2028	3,000,000	3,000,000

Project Life Span	*5 years*
Requesting Organization/Department	A07 / Generation Production Substation Support
Business Case Owner | Sponsor	Greg Wiggins / Alexis Alexander |
Sponsor Organization/Department	Alexis Alexander / GPSS
Phase	Initiation
Category	Program
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM - *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

This program will support the various maintenance projects within all of the Avista-owned generating facilities. These projects are routine, scheduled and time-based maintenance activities intended to extend the life of an asset. Projects within this program are designed to maintain continued operations of the hydro and thermal generating facilities. The projects will be planned and scheduled work. The The driver will primarily be asset conditiona but may vary between individual projects.

Currently there are four similar GPSS programs which include the Base Load Hydro, Base Load Thermal, Regulating Hydro, and Peaking Thermal programs used to fund a multitude of level 0 and level 1 projects. Although the projects are justified the segmented programs create inconsistency in the investment strategy and approach. The combination of the Thermal and Hydro Operations teams will better enable consistent asset management forecasting and prioritization across the entire generation fleet. A single prioritization ranking methodology, and governance structure will improve the effective deployment of resources.

1.2 Discuss the major drivers of the business case.

Major drivers are Asset Condition – Investments to replace assets based on industry accepted, asset management principles and strategies. GPSS Asset Management strategy is designed to optimize the overall lifecycle value for our customers.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The Avista-owned hydro and thermal generating facilities have a wide range of aging equipment. Continual investment will be required for the facilities to meet the demands of future energy markets. This program will support the ongoing maintenance projects spread across the 13 facilities. Examples of these projects include: Nine Mile Roof Replacement, Kettle Falls Dozer Certified Powertrain Replacement, and GSU Monitoring project. The dynmic performance of our assets driven by the evolving energy markets is leading to increased unplanned failures. The proposed business case allows for proactive meansures to maintain unit availably, ultimately contributing to energy costs savings for our customers.

Without this funding source the facilities will lack a minimum project funding to maintain safe, reliable, and affordable operations.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's core business by delivering energy safely, responsibly, and affordably to our customers. Through prudent investments in plant operations we can ensure the generating facilities are reliable and available to respond to the energy market of the future. In addition, many of the investments improve the operational safety of our employees, enabling them to achieve their optimal performance.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

This program will support 13 Avista-owned generating facilities and will fund a number of projects annually. These projects will vary in size and scope and will be governed by the GPSS Operations team including the Plant Managers, Operations Engineering Manager, and the Senior Operations and Maintenance Manager. With the consolidation of hydro and thermal operations, projects will be analyzed, planned, and executed by one group aligning investment decisions for optimal operational performance. Oprerations and Engineering will work together to create supporting documentation jusityfing the investment for each approved project, utilizing existing asset management analysis and maintenance records.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The Asset Lifecyle Management business case is part of a transition from the Regulating Hydro, Base Load Hydro, Base Load Thermal, and the Peaking Thermal business cases. The previous business cases were intended to ensure a balanced approach in investments made in each of the four operational categories. The combination of renewable integration, unprecedented weather patterns, and new energy policy, has changed Avista's resource mix. As a result, the investments necessary to sustain the operation and maintain our facitlies has taken on a new forecasting profile.

The new program, accompanied by an enhanced resource strategy, including the development of plant and regional project teams, will enable better coordinated project delivery for the respective plants. In addition, a centeralized list of projects across Avista's entire generation fleet will be maintained and prioritized. This is essential, as we modify how we dispatch our fleet, balancing affordability and reliability in the rapidly evolvling energy markets.

Past asset management, maintenance, and investment strategies have changed to meet the new demands. The new resource strategy along with the business case program structure will support improved project planning, execution, and the adaptability needed to respond to unplanned events.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Historical data and analysis on the past Regulating, Base Load, Peaking thermal and hydro projects were used to determine expected budget spend amounts for the future. Projects will follow the GPSS risk based investment planning methodology for life cycle analysis, cost benefit and risk reduction. This work will be done by the GPSS Operations Engineering Team. The major component projects will have an average lifecycle look with current asset condition. The first year Risk Cost Reduction will be projected which is the difference between the current risk costs, based on failure rates, and the risk costs of a new assets. This is analogous to; if Avista were to pay an "insurance premium" to pay for probable consequences of failure.

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[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.
[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

DIRECT offsets will be determined for each project, when applicable. This information will be calculated and documented in each project file.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

INDIRECT offsets will be determined for each project, when applicable. This information will be calculated and documented in each project file.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: N/A

Alternative 2: N/A

Alternative 3: N/A

Where applicable, each project will document alternatives that were considered during the research and planning phase. The alternatives for projects will be determined such as direct replacement, manufactures recommendations, and industrial standards.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Projects will be tracked and managed in Maximo asset management program. Historical asset data may be used to compare the project benefits. When available, the data will be used to support the investment decision.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Projects will commence and complete throughout the year over the various plant locations. This process will allow "shovel ready" projects to be quickly put into the queue and executed when funds and resources are available.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Projects will be classified into level 0 and level 1 based on complexity and required coordination. Level 0 projects will utilize the GPSS Operations team consisting of the Plant Manager, Operations Engineering Manager, and Senior Operations and Maintenance Manager for project governance. Projects will be ranked using the GPSS project ranking matrix which focus on various categories including; Personnel and Public Safety, Environmental, Risk of Equipment Failure, Regulatory Mandate, Maintenance Issues, Customer Value, Operating Efficiencies, Operating Costs, and Obsolete Equipment. Level 0 projects are smaller in scope, generally less than $1M, and completed within the calendar year.

Level 1 projects, are larger in scope, schedule, and budget, costing between $1M-$10M and are completed over the course of two years. Level 1 projects will receive a higher level of scrutiny, utilizing the GPSS strategic asset management plan to guide capital replacement strategies. Where data is available, the GPSS risk based investment planning tool will be used to rank asset condition, criticality, and risk costs for level 1 projects.

A dedicated GPSS Program Manager will be responsible for monitoring the program and the associated projects to ensure expected budget and transfer to plant are on target.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the GPSS_Operational Preventive Maintenance 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.

GPSS_Asset Lifecycle Management

Signature: DocuSigned by: Greg Wiggins A2CE32875CC64F9... Date: Aug-11-2023 | 8:36 AM PDT

Print Name: Greg Wiggins

Title: Senior Ops & Maint Manager

Role: Business Case Owner

Signature: DocuSigned by: Alexis Alexander EA27BABA767E467... Date: Aug-15-2023 | 6:51 AM PDT

Print Name: Alexis Alexander

Title: Alexis Alexander

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Asset Monitoring Systems

EXECUTIVE SUMMARY

The yearly amount of $250k is based on Asset Monitoring Systems that are needed to track the condition of our Assets. These systems are in both our Hydro and Thermal Generation Plants. They are not part of the Generation Control System that is used for real-time control and monitoring. There is a need to update the existing systems and install new systems to monitor the condition of our Assets. These Asset Monitoring Systems are used to influence our Maintenance and Capital planning. The budget amounts are based on 2022 quotes for replacing, updating, and installing new systems. These systems will interface with the corporate network and therefore need to be updated periodically to keep up with changing software and security needs.

The risk of not approving this yearly amount will cause our Asset Monitoring Systems to become obsolete and therefore move us back to a reactionary place upon assets failure. This business case has been reviewed and approved by GPSS Management.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Glen Farmer*	*Draft and review*	*4/8/2022*	
2.0	*Glen Farmer*	*SCRUM Update and Approval to move forward.*	*5/18/2022*	
2.1	*Glen Farmer*	*Submit for Approval*	*6/1/2022*	
2.2	*Glen Farmer*	*Finish Business Case Info*	*8/23/2022*	

Asset Monitoring Systems

GENERAL INFORMATION

Requested Spend Amount	$250,000
Requested Spend Time Period	*Per year*
Requesting Organization/Department	G07
Business Case Owner | Sponsor	Glen Farmer | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Initiation
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

1.1 The Generation Plant Assets have asset monitoring that can give us indication of performance and values that can give us trending condition of the asset. These systems become outdated or obsolete based on the manufactures software being unsupported. Also, some systems have a limited number of testing that can be performed based on the system parameters.

1.2 The driver for these Asset Monitoring Systems is Asset Condition. When these systems are working correctly was can use them to give us indication of degrading condition. From there we can start the process of putting a Business Case together before the Asset fails. In the past we would wait until the Asset failed, then we would apply a temporary fix to give us time to start the Business Case process.

1.3 The risk, if not approved, is we would be looking at an indicator of failure, then doing a temporary fix then replace. This takes time to get things approved and in the budget. Our budget is fixed and when failures happen then that moves out other projects.

1.4 We have used these Asset Monitoring Systems to give us indication of the Asset Condition. Based on the trending of the data the condition of the asset will at some point be switched off-line when the Monitoring and Control Systems gives us indication of a failure or potential failure. In the past we have reduced the capacity of system or the runtime of the system to give us some time to get a replacement project going. In these cases, the megawatt output is normally reduced, and we are hoping that it will make it until the fix can be engineered, procured, and installed.

1.5 Supplemental Information

1.5.1 Manufactures letters indicating that product support will no longer be available is the first indication that we receive. When that happens then we can no longer update the computer systems that is running the software. At some point the computer system must be upgraded which brings about a new operating system. The new operating system requires a new interface box, and the software must be upgraded to run on the latest operating system.

2. PROPOSAL AND RECOMMENDED SOLUTION

The recommended solution is to update the Asset Monitoring Systems with the latest manufactures supported equipment to stay current with the interface boxes and updated software so that the computers can be upgraded as they become obsolete.

Option	Capital Cost	Start	Complete
Update the Asset Monitoring System with latest Manufactures supported equipment.	$250,000/year	01/2023	12/2023
Don’t replace system and disconnect from network	$10,000/year	01/2023	12/2023
Hire Manufacture to run data collection and provide recommendation report.	$375,000/year	01/2023	12/2023

2.1 Working with the manufactures of the equipment we requested alternatives for keeping the systems working and updated. To do this we need to purchase the manufactures supported systems. Normally we can save the database and load that in the new system so we can continue the trending of the asset. Sometimes we must start over on the trending. We use industrial standard curves and data points to quantify the asset condition.

2.2 The capital cost will go to the systems that have already failed or have been obsolete and are no longer collecting data. We will concentrate on one Unit per year or one type of system per year.

2.3 The Business Unit will use these Asset Monitoring Systems to trend the Asset Condition which will provide time for the Business Cases to be developed ranked and prioritized and put into our 5-year plan.

2.4 The alternatives of “Don’t replace system and disconnect from network” is a risk of not being able to indicate when we are having issues with an asset. That is fine if we want to run to failure. If that is the case, then upon failure we must figure out what is not going to be done in our plan. That effects manpower and budget changes. Once approved then we must start the project process.

The alternative of "HIRE MANUFACTURE TO RUN DATA COLLECTION AND PROVIDE RECOMMENDATION REPORT" is a risk because it is just a snapshot of the equipment condition at the time the data is taken.

2.5 Given that our install window is the last couple months of each year the material will be purchased in the first year and the install and commissioning will happen in the following year.

2.6 To be reliable we need to have these types of systems to give us data on the condition trends of the Assets.

2.7 As we mature our Asset Management plans these systems will be key to showing when we need to move forward with a capital replacement. They can also give us indication of what Unit needs attention during the maintenance cycles. We will be looking at the data from these systems on a quarterly basis and do a report yearly.

2.8 Supplemental Information

2.8.1 The customers and stakeholders of these systems is the Asset Management and Compliance Engineering team and Operations.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The steering committee will be the Asset Management & Compliance Engineering group. Each project will be discussed and prioritized with other similar projects.

3.2 The governance oversight will be provided by Sr. GPSS Management.

3.3 Decision making on projects will be bast on failed equipment and prioritized based on megawatts output. Changes will be documented in a spreadsheet for tracking the projects.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Asset Monitoring Systems 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:	Glen Farmer Digitally signed by Glen Farmer Date: 2022.08.30 15:49:04 -07'00'	Date:	8/23/2022
Print Name:	Glen Farmer		
Title:	Asset Management & Compliance Engineering Manager		
Role:	Business Case Owner		

Signature:	Alexis Digitally signed by Alexis Date: 2022.09.01 09:04:40 -07'00'	Date:	
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

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

Automation Replacement

EXECUTIVE SUMMARY

The purpose of this program is to replace aging controllers and meters. Controllers are used to automate, control and monitor Avista's generating facilities. Each generating unit has a meter that measures MWh and MVARh. The controllers and meters of concern are aging and introducing an increase in hardware, software, and communication failures that limit Avista's ability to operate generating facilities reliably. The recommended solution is to replace all aging controllers and meters proactively on a schedule that takes into account resources and outage availability. The project cost to replace an outdated meter costs about $40,000 and a controller costs about $300,000-$500,000 depending on the complexity. Proactively replacing these devices benefits customers by reducing unexpected plant outages that require emergency repair with like equipment. A planned approach allows engineers and technicians to update logic programs more effectively and replace hardware with current standards.

When this program was proposed in 2017 a 10-year plan was provided that captured the various controllers through Avista's generating facilities that need to be upgraded. This program funded the replacement of five outdated controllers over the last 3 years. These five controllers are in addition to 10 other controllers that have been replaced as part of other large capital projects. The program allows the overdue replacements of controllers and meters to happen at quicker pace to improve reliability and also support the HMI program and EIM program. The 10-year plan for this program is on track to replace remaining controllers that are outdated over the next seven years. The majority of meters will be upgraded by 2022 in preparation for the EIM. The risk of not continuing this business case slows progress toward replacing aging and outdated controllers and meters that could results in an unplanned outage or a cyber security issue.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Kristina Newhouse*	*Initial draft to convert to new template*	*7/2/2020*	*Existing Business Case. Executive summary only.*
2.0	*Kristina Newhouse*	*Complete remaining template*	*7/31/2020*	*Remaining sections 1, 2, & 3.*

Automation Replacement

GENERAL INFORMATION

Requested Spend Amount	$650,000
Requested Spend Time Period	*10 years*
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner | Sponsor	Kristina Newhouse | Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The purpose of this program is to replace aging Distributed Control Systems (DCS), Programmable Logic Controllers (PLC) and meters. DCSs and PLCs, referred to as controllers, are used throughout Avista's generating facilities to control and monitor Avista's generating units and auxiliary systems. Each generating unit and station service has a meter that measure MWh and MVARh. Controllers collect meter data that is used in logic programs. Controllers and meters used in generating facilities to automate, control, and monitor are aging and introducing an increase in hardware, software, and communication failures that limit Avista's ability to operate generating facilities reliably. The aging hardware of concern requires computer drivers that do not fit in new computers therefore we are required to operate computers with legacy operating systems. This creates a Cyber Security risk.

1.2 Discuss the major drivers of the business case and the benefits to the customer

The major driver of this business case is Asset Condition. Outdated controllers have modules that are over 20 years old and spare parts are limited. Incorporating aging controllers and meters into modern designs is limited and often not possible. Improving the asset condition in this case will improve reliability within the generating facilities.

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

Replacing controllers and meters with new standards will reduce cyber security risk identified in section 1.1 and unexpected plant outages that require emergency repair with like equipment. Planned projects to replace aging controllers and meters before they fail will allow for more efficient upgrades with standardized hardware and software that engineers and technicians are trained on.

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 hardware before it fails and software before it introduces a security risk while moving toward our standardized controllers and meters will be a success. In the past we've planned on upgrading controllers and meters during unit overhauls but this pace is slow when equipment is 20 years old and spare parts are not readily available. The intent of this business case is to increase the number of controllers and meters being replaced today which is about 1-3 controllers and meters a year.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
[Recommended Solution] Upgrade Controllers and Meters	*$6.5M*	*01 2018*	*12 2025*
[Alternative #1] Spare Parts Refurbishment / Do Nothing	*$100k/ year*	*01 2018*	*NA*
[Alternative #2] Software Upgrade	*$2.5M*	*01 2018*	*12 2025*

Alternative 1 is the preferred alternative. It includes replacing all aging controllers and meters proactively on a schedule that takes into account resources, outage availability, and EIM schedule demands. This option addresses aging hardware and software concerns as well as the cyber security vulnerabilities.

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

Information that was considered for this capital request included information from various individuals throughout the company. Technicians shared their challenges maintaining aging controllers and utilizing used spare parts that are often not reliable. It included feedback from operators that have concerns with keeping their plants running using 20 year-old controllers they depend on. Engineers expressed the design limitations they face when asked to install modern systems that tie into outdated technology. IT Security Engineers shared their concerns with technician requiring computers that operate Windows 95 and XP to access the controllers using the software required.

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 for this program takes into consideration that project costs vary depending on the complexity of the controller and meter. Limited resources for design and construction as well as available outages make it necessary for upgrades to be spread out over many years. Upgrading controller & meters will reduce forced outages due to failures and unplanned O&M expenses.

Controllers that need to be replaced that are not part of a larger project in include:

- Upper Falls Unit 1 – design 2019,2020 / Construction tentatively scheduled for 2021
- Control Works – design 2019,2020 / Construction tentatively scheduled for 2021

- Boulder Park Balance of Plant - design 2020, 2021 / Construction tentatively scheduled for 2022
- Post Falls Balance of Plant - TBD
- Noxon Rapids Units 1-5 - TBD
- Coyote Springs Unit 2 -TBD

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 resources are required in order to maintain a schedule and consistently meet the objectives. Engineering will require a designer to develop new logic programs and designs for installations. The Protection Control Meter Shop will need a resource to install and commission the PLC programs. The capital cost takes into account resources needed to perform designs and installations. It also takes into consideration feasibility of plant outages as projects are spread out over time.

This project will benefit Power Supply and System Operations as they are responsible for dispatching power from Cabinet Gorge plant to meet contractual obligations and managing the day-to-day transmission system operational requirements. It will also benefit engineering and the shops as they are responsible for providing maintenance and support with the generating facilities.

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

Alternative 1 is to maintain existing controllers and meters as we currently do today. This includes replacing controller modules as they fail with old spare parts or refurbish third party parts. Maintaining spare parts allows us to continue using existing infrastructure and logic programs but it does not resolve the long-term issue which is aging equipment that will eventually no longer be available. The risk of outages at undesirable times to replace failed parts becomes more likely the longer the aging hardware is in service. This alternative also does not resolve the issue with computers that have unsupported operating systems and are considered a cyber security risk.

Alternative 2 is to upgrade software on the controllers. This would include replacing each system's software that runs on Windows 95 and Windows XP with a separate software for each platform that runs on Windows 10. This will mitigate the software and cyber security issue but not the aging hardware issue. Outages would be required, and the new logic programs would need to be rewritten and fully commissioned. Upgrading the Bailey software and the Modicon software do not align with our standard PLC platform that our engineers and technicians are trained on. This would introduce two new software applications. Efficiency to troubleshoot and resolve issues in a timely manner could be impacted.

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 began in 2018. This business case has funded the replacement of five outdates controllers over the last 3 years. These five controllers are in addition to 10 other controllers that have been replaced as part of other large capital projects. Most designs take place one year with installation and transfer to plant the following year upon competition of the project.

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

By proactively replacing aging controllers and meters we are able to increase reliability within our generating facilities. This program safely, responsibly, and affordably improves our customers' 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

The controllers & meters are both single point failures. If these devices fail they will cause either a single unit outage or a wider plant outage. If spare parts, from the limited supply on hand, can be found then the outage can be minimized but operating generating facility on outdated equipment requiring computers with unsupported operating systems is not sustainable, responsible, or cost effective, and exposes the generating facilities to unnecessary risk.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders that interface with the Automation Replacement Business Case include:

- Controls Engineering
- SCADA Engineering
- Mechanical Engineering
- Project Management
- Network Engineering
- Network Operations
- PCM Shop
- Electric Shop
- Mechanic Shop
- Telecom Shop
- Hydro Operations
- Thermal Operations

2.8.2 Identify any related Business Cases

This business case does not replace any business cases but it is related to the HMI Control Software business case. As new control software and computers with Windows 10 are planned to be installed over the next couple years they need to communicate to controllers and meters. The oldest of the aging controllers require computer drivers that do not fit in new computers.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Each project with have a project manager and steering committee for ongoing vetting. The steering committee for each project will consist of the Controls Engineering Manager, the Protection Control Meter Technician Foreman, the SCADA Engineering Manager, and either the Spokane River Plant Operations Manager, Cabinet Gorge Plant Operations Manager, Noxon Rapids Plant Operations Manager, Lower Spokane River Plant Operations Manager, or Thermal Operations Plant Manager.

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

More detailed project governance protocols will be established during the project chartering process. The Steering Committee will allocate appropriate resources to all project activities, once the scope is better defined.

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

Project decisions will be coordinated by the project manager. The Steering Committee will be advised when necessary. Regular updates will be provided to the Steering Committee by the project manager as project scope, schedule and budget are defined, and through the course of the project execution.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the *Automation 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:	Kristina Newhouse	Date:	8/3/2020
Print Name:	Kristina Newhouse		
Title:	Controls Engineering Manager		
Role:	Business Case Owner		

Signature:	ANdrew Vickers	Date:	8/3/2020
Print Name:	Andy Vickers		
Title:	Director of GPSS		
Role:	Business Case Sponsor		

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

Template Version: 05/28/2020

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name:

   Generation Automation Replacement

2. Business Case Owner:

   Jeremy Winkle

3. Director Responsible:

   Andy Vickers

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

Quantified direct savings:

2022	2023	Lifetime
$0	$0	$0

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

This program replaces automated control systems at Avista's generation facilities that are obsolete and spare parts are no longer available for purchase. These systems are currently operating with a significant risk of an unplanned failure that would require an extend outage to replace the control system.

Operating Avista's generation facilities on obsolete automation control equipment creates a cyber security risk. The software required to maintain and troubleshoot obsolete the control systems is no longer support and must operate on a Windows 7 or older operating system. Since the software systems no longer receive security updates, Avista's generation control network is more vulnerable to cyber security risks and viruses. Replacing obsolete control system with modern systems reduces Avista's risk to cyber assets required to deliver generate reliable power to customers.

Asset analysis of this project results in the "Risk Cost Reduction" shown below, reflective of the premium that would be paid if we were to insure against asset failure during this time frame. This calculated indirect savings considers the condition of the asset, the probability of failure, the probable consequence of failure and other risk factors such as personnel and public safety, environmental impacts, and unplanned outages and repairs.

Quantified indirect savings:

2022	2023	Lifetime
$348	$347	$12,366

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

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

Director Name _______Andy Vickers_______________________________________

Director Signature ______ ___________________________________

Date _____________________10/26/2021_________________________________

Base Load Hydro

EXECUTIVE SUMMARY

Avista's Base Load Hydro plants are all located on the upper Spokane River and are "run of river" plants which means they have little to no storage capacity and their operation is subjected to the flow in the Spokane River and the lake level requirements of Lake Coeur d'Alene, upstream of the plants. The facilities considered in this program are: Post Falls, Upper Falls, Monroe Street and Nine Mile Hydroelectric Developments. This program also includes capital projects at the Generation Control Center and on the Generation Control Network. It can also include some projects at the Post Street 115kV Substation where the two downtown hydro plants are tied into the grid.

The operational availability for these generating units in these plants is paramount. The service code for this program is Electric Direct and the jurisdiction for the program is Allocated North serving our electric customers in Washington and Idaho. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business drivers for the projects in this program are a combination of Asset Condition, Failed (or Failing) Plant, and addressing operational deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operational support issues. Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeopardize plant availability and greatly impact the value to our customers and the stability of the grid.

Due to the age of the facilities more and more critical assets, support systems and equipment are reaching the end of their useful life. This program is critical in continuing to support asset management program lifecycle replacement schedules.

The annual cost of this program is variable and depends on discovery of unfavorable asset condition and the unpredictability of equipment failures.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Bob Weisbeck	Initial draft of original business case	6/29/20	
1.0	Bob Weisbeck	Updated for 2022-2026 Capital Plan	6/22/21	

GENERAL INFORMATION

Requested Spend Amount	$5,432,500
Requested Spend Time Period	5 years
Requesting Organization/Department	C07 / GPSS
Business Case Owner | Sponsor	Bob Weisbeck | Andy Vickers
Sponsor Organization/Department	C07 / GPSS
Phase	Initiation
Category	Program
Driver	Asset Condition / Failed Equipment

1. BUSINESS PROBLEM

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

Due to the age and continuous use of the Base Load Hydro facilities, more and more critical assets, support systems and equipment are reaching the end of their useful life. In addition, it is difficult to predict failures and unscheduled problems of operating hydroelectric generating facilities. This program is critical in providing funding to support the replacement of critical assets and systems that support the reliable operations of these critical facilities.

1.2 Discuss the major drivers of the business case

The major drivers for this business case are Asset Condition and Failed Plant. This program provides funding for small capital projects that are required to support the safe and reliable operation of these hydro facilities. The cost-effective operations and generating capacity of these plants, maximize value for Avista and our customers.

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

Critical asset condition and failed equipment jeopardize the safe and reliable operation of these generating facilities. If problems are not resolved in a timely manner, the plant and plant personnel could be at risk and failed or unavailable critical assets and systems will limit plant availability. This could have a substantial cost impact to Avista and our customers.

Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeopardize plant availability and greatly impact the value to customers and the stability of the 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.

Plant reliability and availability is measured as well as the frequency and nature of forced outages. These metrics will contribute to prioritizing the projects in this program. Historically, this program has funded multiple projects per year which contributed to high unit availability.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The historical drivers of the projects selected to be funded by the program are a mix of Asset Condition, approximately 66% and Failed Plant, approximately 34%. Projects are typically completed within the calendar year.

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.

Being a program, this review will be performed on a project by project basis. This decision will be made by the program Advisory Committee.

Option	Capital Cost	Start	Complete
Regulating Hydro Program	$5,535,000	*01/2022*	*12/2026*
Individual Capital Projects	$5,535,000	*01/2022*	*12/2026*
Perform O&M maintenance	0		

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

Review of the program budget over the period of the last six years has revealed a realistic annual budget is $1,127,500, especially based on the age of the Base Load Hydro plants.

The drivers of the projects selected to be funded by this program are mix Asset Condition (approximately 66%) and Failed Plant (34%). Resolving issues encountered in operating these plants in a timely manner benefits the customers with providing safe, reliable, low cost power which supports the needs of Bulk Electric System and provides value to Avista and our customers.

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 budget program, based on review of the past six years, is approximately $1,127,500. In order support the budget constraints of the department, this amount has been reduced by 10% for 2022. Projects with the lowest risk will be postponed during this period. The projects in this program typically take place within the calendar.

If capital funds were not available for the projects in this program, reliability of the plant would decrease, and more O&M would need to be performed to repair aging equipment instead of replacement. This would be an unacceptable and substantial increase in the O&M expenditures.

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

These projects vary in size and support needed based on the requests from the department and from key stakeholders. The larger projects require formal project management with a broader stakeholder team. Medium to small projects can be implemented by a project engineer or project coordinator and many cases can be handled by contractors managed by the regional personnel. All these projects are prioritized and coordinated by the broader support team.

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

One alternative would be to create business cases using the business case template and process for each of these small projects. There are typically 20 projects a year funded by the program. This would overload the Capital Budget Process with small to medium projects whose governance can be effectively handled by the hydro organization. These projects are specific to these plants and the leadership in hydro operations understand the best the nature and context of these projects.

These projects are somewhat unpredictable. It would be difficult to forecast unforeseen events such as equipment failures and identify critical asset condition that could effectively be put in the annual capital plan.

Another alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their lifecycle. This will be unacceptably expensive and older equipment will become more and more unreliable until it becomes obsolete. Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to unacceptable risk.

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 in this program typically take place during the outages for the Hydro Plants which are typically in the summer and fall of each year. Some projects may have the ability to be performed in the first two quarters of the year. Work performed in and around the dams that require outages is safer and more cost effective after run off has occurred in the rivers.

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

The purpose of this program is to provide funding to small to medium size projects with the objective of keeping our hydroelectric plants reliable and available. This enables these plants to affordably support the power needs of our company and our customers. By taking care of these facilities we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing the projects funded by the program, we ensure that hydro facilities are performing at a high level and serving our customers with affordable and reliable energy.

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

Review of the program budget has revealed that a realistic annual budget is $1,127,000. In order to support the capital budget goals of the GPSS department, this budget was reduced in the short term for 2022 by 10% for that year. Projects with lower risk will be delayed through this period.

The drivers of the projects selected to be funded by this program are mix Asset Condition (approximately 66%) and Failed Plant (34%). Resolving issues encountered in operating these plants in a timely manner benefits the customers with providing safe, reliable, low cost power which supports the needs of Bulk Electric System and provides value to Avista and our customers.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The list of primary customers and stakeholders includes: GPSS, Environmental Resources, Power Supply, Systems Operations, ET, and electric customers in Washington and Idaho.

2.8.2 Identify any related Business Cases

3.1 Advisory Group Information

The Advisory Group for this program consists of the four regional Hydro Managers and the Sr Manager of Hydro Operations and Maintenance.

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

Projects are proposed through various organizations in Generation Production and Substation Support (GPSS) and through key stakeholder such as Environmental Resources, Dam Safety, and Safety and Security. The projects are vetted by the Hydro Advisory Group. With the assistance of Operations, Construction and Maintenance and Engineering, projects are evaluated to determine available options, confirm prudency, and bring potential solutions forward.

This same vetting process is followed for emergency projects and may include other key stakeholders. Over the course of the year, the program is actively managed by the Sr. Manager of Hydro Operations, with the assistance of the Advisory Group. This includes monthly analysis of cost and project progress and reporting of expected spend.

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

Each project request will be evaluated by the Advisory Group which will include the scope, cost and risk associated with the project. The project will be evaluated based on the impact or potential impact of the operation of the Regulating Hydro plants. The selection and approval of the project will be based on the experience and consensus of the Advisory Group.

Depending on the size of the project, a Project Manager or Project Coordinator may be assigned. In this case, the project management process is followed for reporting and identifying and executing change orders. Smaller projects will have a point of contact and financials will be reviewed on a monthly basis by the Advisory Group.

Base Load Hydro

The undersigned acknowledge they have reviewed the Based Load Hydro Program business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: R. S. Weisbeck Date: 6/22/2021

Print Name: R. S. Weisbeck

Title: Manager, Hydro Ops and Maintenance

Role: Business Case Owner

Signature: Andrew Vickers Date: 7/6/2021

Print Name: Andrew Vickers

Title: Director GPSS

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name: Base Load Hydro

2. Business Case Owner: Bob Weisbeck, Sr Manager Hydro Operations and Maintenance

3. Director Responsible: Andy Vickers, Director of Generation Production and Substation Support

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

Response - The projects included in the Base Load Hydro Program consist of a number of individual projects related to the ongoing operations of four Avista's hydroelectric generating plants located on the Spokane River: Post Falls, Upper Falls, Monroe Street and Nine Mile. This program also includes work in support of the Generation Control Center and the Post Street Substation, located in downtown Spokane.

The projects in this program benefit customers because the are necessary to maintain reliability and availability of these generating facilities. The projects replace failed or damaged equipment and equipment that has reached or is near the end of its useful life (asset condition). It can also include projects related to safety and compliance. This work restores critical assets and systems to normal reliability levels. In addition, these projects may add a redundant system or control to improve the resiliency of the generating units and support continued operation in the event of a failure of a system, control, instrument, system disturbance, etc. In addition, projects may be executed to enable units to be returned to service quickly as possible if such an event will cause an outage.

As a result, these project generally to do not carry any direct savings as they are focused on restoring a status quo and not on incremental improvements in reduced maintenance or reduction of labor. While these projects are not intended to directly lead to savings, they are critical to the maintaining the ongoing unit reliability and plant resiliency.

Quantified direct savings:

2022	2023	Lifetime
0	0	

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers

will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Response - The dynamics of operating equipment are such that there are always items that need to be addressed to maintain the at the highest reliability and availability as possible. As work is accomplished as described above, indirect savings are realized in some instances by creating opportunities to re-direct existing labor and expense away from damaged or sub-optimal performing equipment. As these systems and equipment are replaced or improved, maintenance efforts can be directed to other items that need to be addressed.

Historically these projects are described by three main categories: Asset Condition, Equipment Failure, and Safety/Compliance. These projects benefits customers by allowing effective and efficient use of maintenance resources to continue to address necessary improvements with damaged equipment or equipment that is near or has reached the end of its useful life. While it does create a benefit, it does not result in quantifiable offsets that can be reasonably captured.

Quantified indirect savings:

2022	2023	Lifetime

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

Response - In addition to the reliability and availability that provide some direct and indirect but unquantifiable benefits, there are projects that are driven by regulatory compliance and safety related actions. These may or may not be related to the continued operation of the units but are performed to insure employee and public safety or in some instances, avoid fines or penalties for non-compliance. As with other projects, these are not performed to reduce maintenance or reduce labor. Often these add

These projects are part of a program and consist of multiple projects over multiple years, perhaps over one thousand individual projects over nearly 40 years so lifetime impacts are not practical to attain. As presented in the response, the benefits of this work may not result in a direct measured benefit.

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

Director Name Andy Vickers

Director Signature ANdrew Vickers

Date 10/26/2021

Page 2 of 2

Base Load Thermal Program 2022 - 2026

EXECUTIVE SUMMARY

This business case request is for Avista's base load thermal plants: **Kettle Falls** and **Coyote Springs 2**. This program enables these plants to have operational flexibility and are operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and other types of services necessary to provide a stable electric grid and to maximize value to Avista and its customers. Smaller and emergent projects planned for Kettle Falls are identified and prioritized through their plant Budget Committee. The plant Budget Committee utilizes an in-house Maintenance Project Review scoring matrix.

Projects planned specifically for Coyote Springs 2 are identified and prioritized during the Annual Budgeting process, with emergent projects discussed during the Monthly Owners committee meetings between Avista management and Coyote Springs management. Some of the projects that fall within this business case are joint projects between Portland General Electric (PGE) and Avista. Those "common" projects are also reviewed in an owner committee setting during meetings at the plant that take place on a monthly basis.

The operational availability for these plants is paramount. The service code for this program is Electric Direct and the jurisdiction for the program is Allocated North serving our electric customers in Washington and Idaho

Individual projects are identified and approved by the Manager of Thermal Operations and Maintenance, specific plant managers and/or GPSS management. Some specific jobs under this program may require additional financial analysis if they are sufficiently large or there are several options that can be chosen to meet the objective. These projects are reviewed with finance personnel to make sure that they are in the best interest of our customers.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Greg Wiggins*	*Initial draft of original business case*	*7/8/2020*	
	Mike Mecham	*Updated*	*7/6/2021*	*For years 2022 - 2026*

Base Load Thermal Program 2022 - 2026

GENERAL INFORMATION

Requested Spend Amount	$13,950,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	C06, K07 / GPSS
Business Case Owner | Sponsor	Thomas Dempsey | Andy Vickers
Sponsor Organization/Department	A07 / GPSS
Phase	Initiation
Category	Program
Driver	Asset Condition / Failed Equipment

1. BUSINESS PROBLEM

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

Due to the age and continuous use of the base load thermal facilities, more and more critical assets, support systems, and equipment are reaching the end of their useful life. In addition, it is difficult to predict failures and unscheduled problems of operating thermal generating facilities. This program is critical in providing funding to support the replacement of critical assets and systems that support the reliable operations of these critical facilities.

1.2 Discuss the major drivers of the business case

The major drivers for this business case are Asset Condition and Failed Plant. This program provides funding for small capital projects that are required to support the safe and realiable operation of these thermal facilities. The flexible operations and generating capacity of these plants maximize value for Avista and our customers.

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

Critical asset condition and failed equipment jeopardize the safe and reliable operation of these generating facilities. If problems are not resolved in a timely manner, the plant and plant personnel could be at risk and failed or unavailable critical assets and systems will limit plant flexibility and availability. This could have a substantial cost impact to Avista and our customers.

Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeapordize plant availability and greatly impact the value to customers and the stability of the 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.

Plant reliability and availability is measured, as well as the frequency and nature of forced outages. These metrics will contribute to prioritizing the projects in this program. Historically, this program has funded multiple projects per year which contributed to unit availability.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The historical drivers of the projects selected to be funded by the program are a mix of Asset Condition and Failed Plant. Projects are typically completed in the calendar year.

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.

Being a Program, this review will be performed on a project by project basis. This decision will be made by the program Steering Committee.

Using funds from the Base Load Thermal Program, spend $2,790,000 per year in 2022-2026; to "keep the lights on".

Option	Capital Cost	Start	Complete
Base Load Thermal Program	*13,950,000*	*01/2022*	*12/2026*
Individual Capital Projects	*13,950,000*	*01/2022*	*12/2026*

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

2.1

Review of the recent program budget has revealed the a realistic annual budget is $3,100,000. In order to support the capital budget goals of the GPSS department, this budget has been reduced by 10% to $2,790,000 for years 2022 through 2026. Projects with lower risk will be delayed through this period.

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.**

If capital funds were not available for the projects in this program, reliability of the plant would decrease and more O&M would need to be performed to repair aging equipment instead of replacement. This would be an unacceptable and substantial increase in the O&M expenditures.

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

These projects vary in size and support needed from the Department and key stakeholders. The larger projects require formal project management with a broader stakeholder team. Medium to small projects can be implemented by a project engineer or project coordinator and many cases can be handled by contractors mananaged by the regional personnel. All of these projects are prioritized and coordinated by the broader support team.

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

One alternative would be to create business cases using the business case template and process for each of these small projects. There are typically 40-50 projects a year funded by the program. This would overload the Capital Budget Process with small to medium projects whose governance can be effectively handled by the Thermal Organization. These projects are specific to these plants and the leadership in Thermal Operations understand the best the nature and context of these projects.

These projects are somewhat unpredictable. It would be difficult to forecast unforeseen events such as equipment failures and identify critical asset condition that could effectively be put in the annual capital plan.

Another alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their lifecycle. This will be unacceptably expensive and older equipment will become more and more unreliable until it becomes obsolete. Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to unacceptable risk.

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 projects in this program for Kettle Falls and Coyote Springs 2 typically take place during the annual outages, which are typically in May-June of each year.

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

The purpose of this program is to provide funding to small to medium size projects with the objective of keeping our thermal plants reliable and available to support the power needs of our company and our customers affordably. By doing this we support our mission of improving our customer's lives through innovative energy solutions which includes thermal generation. By executing the projects funded by the program, we insure that Thermal Facilities are performing at a high level and serving our customers with affordable and reliable energy.

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

Review of the recent program budget has revealed the a realistic annual budget is $3,100,000. In order to support the capital budget goals of the GPSS department, this budget has been reduced by 10% to $2,790,000 for years 2022 through 2026. Projects with lower risk will be delayed through this period.

The drivers of the projects selected to be funded by this program are mix Asset Condition and Failed Plant. Resolving issues encountered in operating these plants in a timely manner benefits the customers with providing safe, reliable, low cost power which supports the needs of Bulk Electric System and provides value to Avista and our customers.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The list of primary customers and stakeholders includes: GPSS, Environmental Resources, Power Supply, Systems Operations, ET, and electric customers in Washington and Idaho

2.8.2 Identify any related Business Cases

None.

3.1 Steering Committee or Advisory Group Information

The Kettle Falls plant uses a Budget Committee to evaluate, prioritize, and oversee project work at the station. This group consists of the Plant Manager, Asst Plant Manager, Plant Mechanic and a Plant Technician.

The plant Budget Committee utilizes GPSS Department Project Ranking Matrix. The review process focuses around Personnel and Public Safety, Environmental Concerns, Regulatory/Insurance Mandates, Ongoing Maintenance Issues, Decreasing Future Operating Costs, Increasing Efficiency, Managing Obsolete Equipment and Assessing the Risk of Equipment Failure.

For Coyote Springs 2, monthly owners committee meetings between Avista management and Coyote Springs management. Some of the projects that fall within this business case are joint projects between Portland General Electric (PGE) and Avista. Those “common” projects are also reviewed in an owner committee setting during meetings at the plant that take place on a monthly basis.

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

Projects are proposed through various organizations in Generation Production and Substation Support (GPSS) and through key stakeholder such as Environmental Resources, and Safety and Security. The projects are vetted by the Advisory Group. With the assistance of Operations, Construction and Maintenance and Engineering, projects are evaluated to determine available options, confirm prudency, and bring potential solutions forward.

This same vetting process is followed for emergency projects and may included other key stakeholders. Over the course of the year, the program is actively managed by the Plant Managers, with the assistance of their Advisory Groups. This includes monthly analysis of cost and project progress and reporting of expected spend.

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

Projects are proposed through various organizations in Generation Production and Substation Support (GPSS) and through key stakeholder such as Environmental Resources, and Safety and Security. The projects are vetted by the Advisory Group. With the assistance of Operations, Construction and Maintenance and Engineering, projects are evaluated to determine available options, confirm prudency, and bring potential solutions forward.

This same vetting process is followed for emergency projects and may included other key stakeholders. Over the course of the year, the program is actively managed by the Plant Managers, with the assistance of their Advisory Groups. This includes monthly analysis of cost and project progress and reporting of expected spend.

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

Each project request will be evaluated by the Advisory Group which will include the scope, cost and risk associated with the project. The project will be evaluated based on the impact or potential impact of the operation of the Thermal plants. The selection and approval of the project will be based on the experience and consensus of the Advisory Group.

Depending on the size of the project, a Project Manager or Project Coordinator may be assigned. They will follow the project management process for reporting and identifying and executing change orders. Smaller projects will have a point of contact and financials will be reviewed on a monthly basis by the Advisory Group.

The undersigned acknowledge they have reviewed the *Base Load Thermal Program Business Case* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	7/6/2021
Print Name:	Thomas C Dempsey		
Title:	Mgr. Thermal Operations & Maintenance		
Role:	Business Case Owner		

Signature:		Date:	7/6/2021
Print Name:	Andrew Vickers		
Title:	Director GPSS		
Role:	Business Case Sponsor		

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

Template Version: 05/28/2020

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name:

GPSS Base Load Thermal Program

2. Business Case Owner:

Thomas Dempsey

3. Director Responsible:

Andy Vickers

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

Response:

The Base Load Thermal Program provides funding to Coyote Springs 2 and Kettle Falls Generating Station for small to medium size projects. This Program consists of multiple projects between the two generating facilities focusing primarily on a mix of planned equipment replacement projects and failed plant projects. These projects replace failed, damaged and under performing equipment to ensure plant reliability and availability are maintained at a high level. Historical data reveals nearly 60% of the projects are planned asset replacement projects while the remainder of these projects are unplanned equipment failures which directly impact plant operations. One project has been identified for Kettle Falls Generation Station in asphalting the landfill access road scheduled for 2023. This project will have a direct O&M savings through annual road maintenance expenses.

Quantified direct savings:

2022	2023	Lifetime
	$9,500	$65,000

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Response:

Many projects in the Base Load Thermal Program are asset replacement projects in which the asset is replaced with like kind equipment at or near the point of failure. Other projects are time-based and planned asset replacement projects. One project identified for 2022 at Kettle Falls is the purchase of a Certified Power Trane for the D10T dozer.

Asset analysis of some of the projects nested in the Base Load Thermal Program results in the “Risk Cost Reduction” shown below, reflective of the premium that would be paid if we were to insure against asset failure during this time frame. This calculated indirect savings considers the condition of the asset, the probability of failure, the probable consequence of failure and other risk factors such as personnel and public safety, environmental impacts, and unplanned outages and repairs.

Quantified indirect savings:

2022	2023	Lifetime
$93,408	$118,119	$339,699

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista’s customers will endure due to non-compliance.

Response:

In addition to the reliability and resiliency that provide some direct and indirect but unquantifiable benefits, there are projects that provide no direct benefits. These projects consist of regulatory compliance and legally required projects that either allow units to continue to operate or in some instances, avoid fines or penalties for non-compliance. As with other projects, these are not performed to reduce maintenance or reduce labor. Often these add burden to these elements and increase costs to operate the units. One project identified at Kettle Falls is the annual landfill cover that is required to be installed by the Department of Ecology.

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

Director Name _______Andy Vickers____

Director Signature _____ ____

Date ________________10/27/2021_______________________________________

GPSS_Operational Sustainment

EXECUTIVE SUMMARY

The diverse Avista-owned generating facilities include Hydro, Biomass, and Natural Gas fuel power producing resources. The assets range in age, condition, output, and configuration. Together these facilities bring a balanced approach to meeting our electric customers needs throughout the year. The 13 Avista-owned generating facilities have a total capacity of nearly 1.6GW of electricity. These facilities include 8 hydroelectric dams located on the Clark Fork and Spokane Rivers, a stand-alone biomass facility located in Kettle Falls, Washington, and four natural gas generating plants spread between in Idaho, Washington, and Oregon.

This program will support the operational sustainability of the Avista-owned generating facilities. These projects primarily include moderate investments in sytem retrofits or replacements necessary to maintain the operation of the facilities. Projects will be level 0 to level 1 in project complexity and coordination. This program is critical in continuing to support asset management program lifecycle replacement schedules until larger operational enhancement program investments are made. Identified projects will be governed by the Plant Manager, Operations Engineering Manager, and Senior Operations & Maintenance Manager.

The GPSS Operations team will coordinate and manage a 5 year plan of identified projects needed to sustain the safe,reliable, and affordable operations of the Avista-owned generation assets. The annual cost of this program is variable and depends on evaluation of asset condition.

This project will impact customers in service code Electric Direct jurisdiction Allocated North serving our electric customers in Washington and Idaho.

VERSION HISTORY

Version	Author	Description	Date
1.0		*Initial draft of original business case*	
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*	

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	15,000,000	15,000,000
2025	15,000,000	15,000,000
2026	16,000,000	16,000,000
2027	17,000,000	17,000,000
2028	17,000,000	17,000,000

Project Life Span	*5 years*
Requesting Organization/Department	A07 / Generation Production Substation Support
Business Case Owner | Sponsor	Greg Wiggins / Alexis Alexander |
Sponsor Organization/Department	Alexis Alexander / GPSS
Phase	Initiation
Category	Program
Driver	Performance & Capacity

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

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?

This program will support the operational sustainabilty of the Avista-owned generating facilities. These projects are moderate investments, retrofits or system improvements intended to maintain the operations of the facilities. Projects within this program are designed to maintain continued operations of the hydro and thermal generating facilities. The projects will be planned and scheduled work. The The driver will primarily be performance and capacity, but may vary between individual projects.

Currently there are four similar GPSS programs which include the Base Load Hydro, Base Load Thermal, Regulating Hydro, and Peaking Thermal programs used to fund multitude of level 0 and level 1 projects. Although the projects are justified the segmented programs create inconsistency in the investment strategy and approach. The combination of the Thermal and Hydro Operations teams will better enable consistent asset management forecasting and prioritization across the entire generation fleet. A single prioritization ranking methodology, and governance structure will improve the effective deployment of resources.

1.2 Discuss the major drivers of the business case.

Major drivers include Performance and Capacity – Investments into hydro and thermal generation to maintain a level of unit availability and to achieve efficiency output objectives.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The Avista-owned hydro and thermal generating facilities have a wide range of aging equipment. Continual investment will be required for the facilities to meet the demands of future energy markets. This program will support the ongoing replacement and upgrade projects spread across the 13 facilities. Examples of these projects include: Emergency Standby Generator Replacement, Plant HVAC Replacement, and Unit Governor Replacement projects. The dynmic performance of our assets driven by the evolving energy markets is leading to increased unplanned failures. The proposed business case allows for proactive, and when necessary, reactive measures to maintain unit availably, ultimately contributing to energy costs savings for our customers.

Without this funding source the facilities will lack a minimum project funding to sustain safe, reliable, and affordable operations.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

This program aligns with Avista's core business by delivering energy safely, responsibly, and affordably to our customers. Through prudent investments in plant operations, we can ensure the generating facilities are reliable and available to respond to the energy market of the future,. In addition, many of the investments improve the operational safety of our employees, enabling them to achieve their optimal performance.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

This program will support 13 Avista-owned generating facilities and will fund a multitude projects annually. These projects will vary in size and scope and will be governed by the GPSS Operations team including the Plant Managers, Operations Engineering Manager, and the Senior Operations and Maintenance Manager. With the consolidation of hydro and thermal operations, projects will be analyzed, planned, and executed by one group aligning investment decisions for optimal operational performance. Oprerations and Engineering will work together to create supporting documentation jusityfing the investment for each approved project, utilizing existing asset management analysis and maintenance records.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION - *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

The Operational Sustainment business case is part of a transition from the Regulating Hydro, Base Load Hydro, Base Load Thermal, and the Peaking Thermal business cases. The previous business cases were intended to ensure a balanced approach in investments made in each of the four operational categories. The combination of renewable integration, unprecedented weather patterns, and new energy policy, has changed Avista's resource mix. As a result, the investments necessary to sustain the operation and maintain our facitlies has taken on a new forecasting profile.

The new program, accompanied by an enhanced resource strategy, including the development of plant and regional project teams, will enable better coordinated project delivery for the respective plants. In addition, a centeralized list of projects across Avista's entire generation fleet will be maintained and prioritized. This is essential, as we modify how we dispatch our fleet, balancing affordability and reliability in the rapidly evolvling energy markets.

Past asset management, maintenance, and investment strategies have changed to meet the new demands. The new resource strategy along with the business case program structure will support improved project planning, execution, and the adaptability needed to respond to unplanned events.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

Historical data and analysis on the past Regulating, Base Load, Peaking thermal and hydro projects were used to determine expected budget spend amounts for the future. Projects will follow the GPSS risk based investment planning methodology for life cycle analysis, cost benefit and risk reduction. This work will be done by the GPSS Operations Engineering Team. The major component projects will have an average lifecycle look with current asset condition. The first year Risk Cost Reduction will be projected which is the difference between the current risk costs, based on failure rates, and the risk costs of a new assets. This is analogous to; if Avista were to pay an "insurance premium" to pay for probable consequences of failure.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

DIRECT offsets will be determined for each project where applicable. This information will be calculated and documented in each project file.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital		$	$	$	$	$
O&M		$	$	$	$	$

INDIRECT offsets will be determined for each project, when applicable. This information will be calculated and documented in each project file.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

Alternative 1: N/A

Alternative 2: N/A

Alternative 3: N/A

Where applicable, each project will document alternatives that were considered during the research and planning phase. The alternatives for projects will be determined such as direct replacement, manufactures recommendations, and industrial standards.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Projects will be tracked and managed in Maximo asset management program. Historical asset data may be used to compare the project benefits. When available, the data will be used to support the investment decision.

2.7 Please provide the timeline of when this work is schedule to commence and complete, if known.

Projects will commence and complete throughout the year over the various plant locations. This process will allow “shovel ready” projects to be quickly put into the queue and executed when funds and resources are available.

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Projects will be classified into level 0 and level 1 based on complexity and required coordination. Level 0 projects will utilize the GPSS Operations team consisting of the Plant Manager, Operations Engineering Manager, and Senior Operations and Maintenance Manager for project governance. Projects will be ranked using the GPSS project ranking matrix which focus on various categories including; Personnel and Public Safety, Environmental, Risk of Equipment Failure, Regulatory Mandate, Maintenance Issues, Customer Value, Operating Efficiencies, Operating Costs, and Obsolete Equipment. Level 0 projects are smaller in scope, generally less than $1M, and completed within the calendar year.

Level 1 projects, are larger in scope, schedule, and budget, costing between $1M-$10M and are completed over the course of two years. Level 1 projects will receive a higher level of scrutiny, utilizing the GPSS strategic asset management plan to guide capital replacement strategies. Where data is available, the GPSS risk based investment planning tool will be used to rank asset condition, criticality, and risk costs for level 1 projects.

A dedicated GPSS Program Manager will be responsible for monitoring the program and the associated projects to ensure expected budget and transfer to plant are on target.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the GPSS_Operational Sustainment 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.

DocuSigned by:

Signature: Greg Wiggins Date:

A2CE32875CC64F9...

Print Name: Greg Wiggins

Title: Senior Ops & Maint Manager

Role: Business Case Owner

DocuSigned by:

Signature: Alexis Alexander Date:

EA27BABA767F467...

Print Name: Alexis Alexander

Title: Alexis Alexander

Role: Business Case Sponsor

Signature: Date:

Print Name:

Title:

Role: Steering/Advisory Committee Review

Regulating Hydro

EXECUTIVE SUMMARY

Avista's regulating hydro plants are unique in that they have storage available in their reservoirs. This enables these plants to have operational flexibility and are operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and other types of services necessary to provide a stable electric grid and to maximize value to Avista and its customers. These plants are the four largest hydro plants on Avista's system representing more than 950 MW of power and include Noxon Rapids and Cabinet Gorge on the Clark Fork River in Montana and Idaho and Long Lake and Little Falls on the Spokane River.

The operational availability for these generating units in these plants is paramount. The service code for this program is Electric Direct and the jurisdiction for the program is Allocated North serving our electric customers in Washington and Idaho. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business drivers for the projects in this program is a combination of Asset Condition, Failed (or Failing) Plant, and addressing operational deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operational support issues. Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeopardize plant availability and greatly impact the value to customers and the stability of the grid.

Due to the age of the facilities more and more critical assets, support systems and equipment are reaching the end of their useful life. This program is critical in continuing to support asset management program lifecycle replacement schedules.

The annual cost of this program is variable and depends on discovery of unfavorable asset condition and the unpredictability of equipment failures.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Bob Weisbeck	Initial draft of original business case	6/29/20	
1.0	Bob Weisbeck	Final signed business case	7/2/20	
1.0	Bob Weisbeck	Updated for 2022-2026 Capital Plan	6/22/21	

Regulating Hydro

GENERAL INFORMATION

Requested Spend Amount	$17,150,000
Requested Spend Time Period	5 years
Requesting Organization/Department	L07, D07, I07 / GPSS
Business Case Owner | Sponsor	Bob Weisbeck | Andy Vickers
Sponsor Organization/Department	A07 / GPSS
Phase	Initiation
Category	Program
Driver	Asset Condition / Failed Equipment

1. BUSINESS PROBLEM

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

Due to the age and continuous use of the regulating hydro facilities, more and more critical assets, support systems and equipment are reaching the end of their useful life. In addition, it is difficult to predict failures and unscheduled problems of operating hydroelectric generating facilities. This program is critical in providing funding to support the replacement of critical assets and systems that support the reliable operations of these critical facilities.

1.2 Discuss the major drivers of the business case

The major drivers for this business case are Asset Condition and Failed Plant. This program provides funding for small capital projects that are required to support the safe and reliable operation of these hydro facilities. The flexible operations and generating capacity of these plants, maximize value for Avista and our customers.

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

Critical asset condition and failed equipment jeopardize the safe and reliable operation of these generating facilities. If problems are not resolved in a timely manner, the plant and plant personnel could be at risk and failed or unavailable critical assets and systems will limit plant flexibility and availability. This could have a substantial cost impact to Avista and our customers.

Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeopardize plant availability and greatly impact the value to customers and the stability of the 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.

Plant reliability and availability is measured as well as the frequency and nature of forced outages. These metrics will contribute to prioritizing the projects in this program. Historically, this program has funded multiple projects per year which contributed to high unit availability.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The historical drivers of the projects selected to be funded by the program are a mix of Asset Condition, approximately 87% and Failed Plant, approximately 13%. Projects are typically completed in the calendar year. The work is primarily performed in the 3rd and 4th quarters of the year when outage in the Hydro Plants are scheduled, typically after run off in the rivers has subsided.

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.

Being a program, this review will be performed on a project by project basis. This decision will be made by the program Advisory Group.

Option	Capital Cost	Start	Complete
Regulating Hydro Program	$17,150,000	*01/2022*	*12/2026*
Individual Capital Projects	$17,150,000	*01/2022*	*12/2026*
Perform O&M maintenance	0		

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

Review of the program budget over the period of the last six years has revealed a realistic annual budget is $3.5 Million.

The drivers of the projects selected to be funded by this program are mix Asset Condition (approximately 87%) and Failed Plant (13%). Resolving issues encountered in operating these plants in a timely manner benefits the customers with providing safe, reliable, low cost power which supports the needs of Bulk Electric System and provides value to Avista and our customers.

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 budget program, based on review of the past six years, is approximately $3.5 million. In order support the budget constraints of the department, this amount has been reduced by 10% for 2022. Projects with lower risk will be delayed through this period. The projects in this program typically take place during the outages which are in the summer and fall of each year. Most of the capital is deployed in the 3rd and 4th quarter of each year.

If capital funds were not available for the projects in this program, reliability of the plant would decrease, and more O&M would need to be performed to repair aging equipment instead of replacement. This would be an unacceptable and substantial increase in the O&M expenditures.

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

These projects vary in size and support needed based on the requests from the department and from key stakeholders. The larger projects require formal project management with a broader stakeholder team. Medium to small projects can be implemented by a project engineer or project coordinator and many cases can be handled by contractors managed by the regional personnel. All these projects are prioritized and coordinated by the broader support team.

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

One alternative would be to create business cases using the business case template and process for each of these small projects. There are typically 40-50 projects a year funded by the program. This would overload the Capital Budget Process with small to medium projects whose governance can be effectively handled by the hydro organization. These projects are specific to these plants and the leadership in hydro operations understand the best the nature and context of these projects.

These projects are somewhat unpredictable. It would be difficult to forecast unforeseen events such as equipment failures and identify critical asset condition that could effectively be put in the annual capital plan.

Another alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their lifecycle. This will be unacceptably expensive and older equipment will become more and more unreliable until it becomes obsolete. Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to unacceptable risk.

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 in this program typically take place during the outages for the Hydro Plants which are typically in the summer and fall of each year. Some projects may have the ability to be performed in the first two quarters of the year but most of the capital is deployed in the 3rd and 4th quarter of each year. Work performed in and around the dams that require outages typically is safer and more cost effective after run off has occurred in the rivers.

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

The purpose of this program is to provide funding for small to medium size projects with the objective of keeping our hydroelectric plants reliable and available. These plants affordably support the power needs of our company and our customers. By taking care of these plants we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing the projects funded by the program, we ensure that hydro facilities are performing at a high level and serving our customers with affordable and reliable energy.

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

Review of the program budget has revealed that a realistic annual budget is $3.5 Million. In order to support the capital budget goals of the GPSS department, this budget was reduced in the short term for 2022 by 10% for that year. Projects with lower risk will be delayed through this period.

The drivers of the projects selected to be funded by this program are mix Asset Condition (approximately 87%) and Failed Plant (13%). Resolving issues encountered in operating these plants in a timely manner benefits the customers with providing safe, reliable, low cost power which supports the needs of Bulk Electric System and provides value to Avista and our customers.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The list of primary customers and stakeholders includes: GPSS, Environmental Resources, Power Supply, Systems Operations, ET, and electric customers in Washington and Idaho.

2.8.2 Identify any related Business Cases

3.1 Advisory Group Information

The Advisory Group for this program consists of the four regional Hydro Managers and the Sr Manager of Hydro Operations and Maintenance.

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

Projects are proposed through various organizations in Generation Production and Substation Support (GPSS) and through key stakeholder such as Environmental Resources, Dam Safety, and Safety and Security. The projects are vetted by the Hydro Advisory Group. With the assistance of Operations, Construction and Maintenance and Engineering, projects are evaluated to determine available options, confirm prudency, and bring potential solutions forward.

This same vetting process is followed for emergency projects and may include other key stakeholders. Over the course of the year, the program is actively managed by the Sr. Manager of Hydro Operations, with the assistance of the Advisory Group. This includes monthly analysis of cost and project progress and reporting of expected spend.

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

Each project request will be evaluated by the Advisory Group which will include the scope, cost and risk associated with the project. The project will be evaluated based on the impact or potential impact of the operation of the Regulating Hydro plants. The selection and approval of the project will be based on the experience and consensus of the Advisory Group.

Depending on the size of the project, a Project Manager or Project Coordinator may be assigned. In this case, the project management process will be followed for reporting and identifying and executing change orders. Smaller projects will have a point of contact and financials will be review on a monthly basis by the Advisory Group.

The undersigned acknowledge they have reviewed the Regulating Hydro Program business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	R. S. Weisbeck	Date:	6/22/2021
Print Name:	R. S. Weisbeck		
Title:	Manager, Hydro Ops and Maintenance		
Role:	Business Case Owner		

Signature:	ANdrew Vickers	Date:	7/6/2021
Print Name:	Andrew Vickers		
Title:	Director GPSS		
Role:	Business Case Sponsor		

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

Template Version: 05/28/2020

2022-2023 CAPITAL PROJECT

SAVINGS AND PRODUCTIVITY REPORTING FORM

1. Business Case Name: Regulating Hydro

2. Business Case Owner: Bob Weisbeck, Sr Manager Hydro Operations and Maintenance

3. Director Responsible: Andy Vickers, Director of Generation Production and Substation Support

4. **Direct Savings** - Description of Estimated Direct Savings Resulting from this Business Case (please describe and quantify any hard cost savings Avista's customers will gain due to the work under this project. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other):

Response - The projects included in the Regulating Hydro Program consist of a number of individual projects related to the ongoing operations of Avista's four largest hydroelectric generating plants, Noxon Rapids, Cabinet Gorge, Long Lake and Little Falls.

The projects in this program benefit customers because the are necessary to maintain reliability and availability of these generating facilities. The projects replace failed or damaged equipment and equipment that has reached or is near the end of its useful life (asset condition). It can also include projects related to safety and compliance. This work restores critical assets and systems to normal reliability levels. In addition, these projects may add a redundant system or control to improve the resiliency of the generating units and support continued operation in the event of a failure of a system, control, instrument, system disturbance, etc. In addition, projects may be executed to enable units to be returned to service quickly as possible if such an event will cause an outage.

As a result, these projects generally to do not carry any direct savings as they are focused on restoring a status quo and not on incremental improvements in reduced maintenance or reduction of labor. While these projects are not intended to directly lead to savings, they are critical to the maintaining the ongoing unit reliability and plant resiliency.

Quantified direct savings:

2022	2023	Lifetime
0	0	

5. **Indirect Savings** - Description of Estimated Indirect Savings and/or Productivity Gains Resulting from this Project (please describe and quantify any indirect cost savings or productivity gains Avista's customers will gain from this project). For example, deploying this capital investment reduces the future need to hire X number of employees. For a new substation or transmission line, are there efficiencies to be gained from less line losses. Or, if we don't do this project now, if may cost more in the future (cost avoidance).

Response - The dynamics of operating equipment are such that there are always items that need to be addressed to maintain them at the highest reliability and availability as possible. As work is accomplished as described above, indirect savings are realized in some instances by creating opportunities to re-direct existing labor and expense away from damaged or sub-optimal performing equipment. As these systems and equipment are replaced or improved, maintenance efforts can be directed to other items that need to be addressed.

Historical these projects are described by in three categories: Asset Condition, Equipment Failure, and Safety/Compliance. These projects benefits customers by allowing effective and efficient use of maintenance resources to continue to address necessary improvements with damaged equipment or equipment that is near or has reached the end of its useful life. Specific projects are difficult to forecast since the purpose of the program is to address equipment failures and asset condition and compliance issues as they arise. While it does create a benefit, it does not result in quantifiable offsets that can be reasonably captured.

Quantified indirect savings:

2022	2023	Lifetime

6. No Direct or Indirect Savings – These are projects where there are NO identifiable direct or indirect cost savings for customers, as they are required by law, or simply after thorough review have no offsets. (For these projects, please think through any potential offsets, as having no offsets is a high hurdle). If the work is required by law or rule, please identify the law and describe and quantify any risk or penalty Avista's customers will endure due to non-compliance.

Response - In addition to the reliability and availability that provide some direct and indirect but unquantifiable benefits, there are projects that are driven by regulatory compliance and safety related actions. These may or may not be related to the continued operation of the units but are performed to insure employee and public safety or in some instances, avoid fines or penalties for non-compliance. As with other projects, these are not performed to reduce maintenance or reduce labor. Often these add burden to labor and non-labor costs which may result in the increased cost of operating the units.

These projects are part of a program and consist of multiple projects over multiple years, perhaps over one thousand individual projects over nearly 40 years so lifetime impacts are not practical to attain. As presented in the response, the benefits of this work may not result in a direct measured benefit other than the ongoing reliability and availability of these low cost, renewable generating resources

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

Director Name Andy Vickers

Director Signature ANdrew Vickers

Date 10/26/2021

HMI Control Software

EXECUTIVE SUMMARY

PROJECT NEED: The existing Human Machine Interface (HMI) software, Wonderware, reached its end of life as support ended in 2017. HMI Control Software is used to develop control screens and to operate and monitor generating systems within Avista Hydroelectric Developments and Thermal Generating facilities. The existing architecture is also outdated and requires the existing software to be loaded and run on each individual computer at each generating facility. Moving to a new HMI platform will allow for upgrading to a server-based architecture.

RECOMMENDED SOLUTION: The HMI Control Software update is a multi-year effort to transition the controls software at all GPSS generating facilities from Wonderware to Ignition. As a part of this updated, supporting software and hardware will also need to be upgraded as to ensure communication and support across all parts of our controls system. The timing of this transition is critical due to the expiring support for both Wonderware and Windows 7 (the current, and only, operating system functional with Wonderware).

ALTERNATIVES CONSIDERED: The alternatives considered ranged from inaction to complete product replacement. The selection of complete replacement was made based upon the risk/reward analysis performed at the onset of the project. The decision to procure and design an entirely new solution better positions Avista for the future and mitigates more of the long-term risks associated with sunsetting technologies.

COST OF RECOMMENDED SOLUTION: $17,800,000
$7M through 2022, $5M planned spend in 2023, $5.8 requested in 2024-2028 CPG cycle.

ADDITIONAL INFO: This project will benefit customers as the transition is integral to the continued safe and reliable operation of our generating units. Risk likelihood, exposure, and severity increase the longer we continue to operate on extended service agreements and unsupported technology. If we do not stay current with supporting operating systems, then cyber security risks increase. Additionally, continuing operations on unsupported equipment puts our facilities at an increased risk of technology failure with much longer repair durations and continually increasing costs for support.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Kit Parker	Original submission	7/17/2017	Signed/approved
1.1	Kara Heatherly	Conversion to new format	6/20/2020	Includes budget update
2.0	Kara Heatherly	Update for current budget projects and new schedule	7/9/2021	
3.0	Kristina Newhouse & Kara Hensley	Updated to 2022 template and to reflect most current 5-year plan	8/25/2022	
4.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$3,000,000	$ 2,300,000
2025	$2,500,000	$ 3,000,000
2026	$ 300,000	$ 2,000,000
2027	$ 0	$ 0
2028	$ 0	$ 0

Project Timelines: Ignition Go-Live *(Earliest Possible Cutover Start Dates)*

Site conversion began in 2020 and will continue in accordance with the graphic above showing the remaining planned cutovers within the 5-year planning window. These dates reflect anticipated start dates for cutover work. Some cutover activities may be re-sequenced due to the nature of the required outage, coordination with Power Supply for minimally impactful outage scheduling, and in some cases "outage" activities range from 2 weeks (Ignition cutover only) per PLC to upwards of 6 weeks per PLC (full PLC replacement).

Project Life Span	8 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

[Investment Drivers]

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

The existing Human Machine Interface (HMI) software, Wonderware has reached end of life as support ended in 2017. HMI Control Software is a platform used to control generating systems within Avista Hydroelectric Developments and Thermal Generating facilities. The HMI screens allow an operator to run the station from a computer in a control room rather than directly from the equipment on the generating floor. New control screens need to be developed using a new software platform and that new software platform needs to exist on new technology infrastructure (servers, network, PCs etc.). The major driver for the HMI Control Software business case is the Asset Condition. This project aligns with Avista's Safe & Reliable Infrastructure strategy.

The existing architecture is outdated and requires software to be run on each individual computer. Moving to a new HMI platform will require moving to a server-based architecture.

1.2 Discuss the major drivers of the business case

Asset Condition: New HMI control software is needed now to prevent limitations going forward that will introduce security risks. The existing HMI software runs on Windows 7, which is planned to be unsupported after 2020.

Developing new controls screens on a new software platform will modernize control screens and allow operators to carry out their responsibilities more effectively. Control Screen will need to be developed for each generating facility; therefore, a planned approach will allow engineering and technicians to develop screens over time to coordinate with control upgrades.

In addition, a new server-based architecture will also create efficiencies for technicians as they will be able to maintain and update screens remotely.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

If we do not stay current with supporting operating systems, then cyber security risks increase. Additionally, continuing operations on unsupported equipment puts our facilities at an increased risk of technology failure with much longer repair durations and continually increasing costs for support.

Currently, failure of the controls system at our generating facilities would be nearly immediately catastrophic. Especially at remote facilities where resources are not physically available to bring systems online and facilities are not staffed to assume fully manual operations, having a central system "brain" for these functions is essential to keeping the system online and, if necessary, getting the system back online quickly. Minimizing the severity of non-preventable failure is the prudent and responsible thing to do.

Additionally, operating systems that are no longer supported on extended maintenance agreements is not sustainable, responsible, or cost effective, and exposes the plants to unnecessary risk.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*.

Avista Strategic Goals

Mission: This project safely, responsibility and affordably improves the level of service we provide to our customers by minimizing direct impacts to services. This innovative approach allows us to pilot software updates and configurations before implementing on active sites. This in turn, shortens our outage time and allows our operations team to reserve capacity for other critical needs

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

As an example, the existing HMI software runs on Windows 7, which has been unsupported since 2020.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: The preferred alternative is to purchase new HMI control software that better meets the need of operators, protection control and meter (PCM) technicians, and engineers.

The successful implementation of this new control software will improve remote monitoring and controls at all our facilities, secure and protect Avista's critical infrastructure, and minimize the impact of future technology upgrades and versioning on plant operations.

Bringing this system up to date will also ensure continued support from ET Applications, software licensing and versioning, as well as visibility into potential network and version conflicts. The Ignition design will also provide our PCM techs with real-time support from Controls Engineering by providing read-only access to the plant control screens from the Mission campus.

The alternatives considered ranged from inaction to complete product replacement. The selection of complete replacement was made based upon the risk/reward analysis performed at the onset of the project. The decision to procure and design an entirely new solution better positions Avista for the future and mitigates more of the long-term risks associated with sunsetting technologies.

In scope: 12 Generating Facilities are in the scope of this replacement project.

- Monroe Street/Post Street
- Upper Falls/Control Works
- GCC (Generation Control Center)
- Rathdrum
- Boulder Park
- Northeast
- Long Lake
- Little Falls
- Nine Mile
- Post Falls
- Noxon

- Cabinet

The following scope components apply to all 12 facilities:

- Replacement of Wonderware with Inductive Automation Ignition product. Such replacement requires: design of new screens, tag naming/architecture changes across all facilities for standardization, integration with Pi, upgrades to Windows10 supported equipment, addition of two servers (one primary and one backup at each generating facility), addition of two firewalls at each generating facility and central Generation Control Network facility, addition of redundant plant switches on the primary Generation Control Network, and transition to new network architecture/isolated Generation Control Network for added security and to meet current cyber security compliance requirements.

The following scope components apply to some of the 12 facilities:

- Depending on the age of the controls infrastructure at each of the 12 plants, some PLC's need to be upgraded from Bailey and Modicon (non-Win10 supported systems) to new Allen Bradley technology. As the project timeline is continually refined, the Steering Committee is asked to evaluate the value to the company of pursuing synergies in line with this project's schedule. In some cases, the decision has been to bring PLC replacements into the HMI program, and in other cases, due to the nature, driver, complexity, timing, and planned future of other facilities, the decision has been to keep the work separate (or reduce the HMI scope of work to avoid later rework). These decisions are made on a case-by-case basis and are evaluated at strategic project life cycle phase gates to avoid rework and waste.
  - **Examples of PLC replacements in the HMI Program:** LL Bailey Replacement, PF Bailey Replacement

  The following scope components are outside of the HMI program scope at this time, even though in some cases the execution of these projects is still coordinated with the HMI timeline, again, to avoid rework, and minimize total generation (availability) impacts. Examples include:

- Any upgrades to the CORP network are excluded from this project
- EOL network hardware (switches) replaced in kind is being replaced under the coordinated, ET funded, VDR program.

- Any transport/backhaul enhancements addressing network infrastructure technical debt/single points of failure are not included in the scope of this project. In some cases, other projects funding this work may be coordinated with HMI outages to reduce total impact to generation.

- Some PLC replacements are excluded from this project

    - **Examples of PLC replacements outside of the HMI Program**: Noxon Rapids Units 1-5 PLCs *(Funding in Automation Replacement, scheduled to align with HMI),* Nine Mile Units 3 and 4 Controls Upgrade *(Controls design coordinated to maximize efficiency and reduce total time in design)* UF Unit Upgrade, Boulder Park Balance of Plant PLC *(Funding in Automation Replacement, scheduled to align with HMI)*

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- The budgetary refinement for this project has been an ongoing joint effort between GPSS and ET based in constant re-evaluation of actual spend against forecasts. In a lot of ways, this work is very new to both business units. The level of complexity involved in building network redundancy, designing to new security standards, standardizing controls data points and hierarchies, and designing custom plant screens and layouts that meet the diverse needs of our plants has proven much more complicated than originally anticipated.

  At project inception, an alternatives analysis was conducted between the proposed potential product offerings (Cimplicity, Ignition, Wonderware, etc.) and a cross-functional team of controls experts, operations staff, PCM technicians and ET operations support staff selected the product that would be the most scalable to our plants' diverse needs and the most supportable over time. The costs of the products were relatively equal and the cost of the effort to bring the plants up to standard (operations on Win10) were distinct from any vendor technology decision.

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

The decision to add the interface PLCs at some of the plants was a cost-saving to defer the need to expedite the timeline to obsolete the Bailey and Modicon systems - a multi-million dollars savings to the company's capital proforma. This decision also allows us to continue to operate safely and reliably on our Bailey and Modicon systems for longer without exposing the network to undue security risk. Similarly, the decision to replace Unit PLC's at Noxon, while adding cost to the project, reduced the overall cost to the company by eliminating rework and replacement cost that would be incurred by the plant in the near future. The estimate savings on this work is $1M.

2.3 Summarize in the table and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	Server Hardware (CS) Support: Win7 Support Contract (extended) net out with Win10 support contract Application Ongoing Support: Inductive Automation Support agreement, budget from App Ops for support, net with current support (from PCM) Network Support Cost (net out from what it has been, cost of maintenance, management, repair, troubleshooting, what about risk cost due to technical debt, single points of failure, can we calculate a value?)	$x	$X	X	X	X

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

It is expected that a server-based architecture will reduce O&M costs as it will allow for modifications to be made to HMI control screens from one central location and eliminate the need to drive to each facility when changes are required. However, the servers will require ongoing support, therefore increasing O&M costs. Eliminating the extended Windows 7 support contract will also reduce O&M costs.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	Put PCM calc from above down here for availability for higher priority/core competency work. Potential savings through centralization of Generation Control and changed Local Control/Dispatch Model – not likely to be realized in 5-year window. Security cost reduction due to security of Win10 as opposed to ongoing oversight/risk exposure of the network due to Win7	$x	x	x	x	x

Indirect offsets are not quantifiable at this time due to the unknown future of our generation control and operator dispatch model. This HMI enhancement, however, does afford the Company the functional capability to operate facilities in a remote state without a full-time local (on-site) control presence. No additional hires are forecast in current budgets to sustain the current system design and support operations at this time. Potential efficiencies could be gained with the ability to redirect PCM (Protection Control Meter Tech) time and capacity to other core function work. However, the current support work for Wonderware performed by the PCM Techs will be replaced by a central support model shared by ET Application Operations and a support contract with the vendor (Inductive Automation) both with an additional cost to the Company.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: The preferred alternative is to purchase new HMI control software that better meets the need of operators, protection control and meter (PCM) technicians, and engineers.

CONSIDERED ALTERNATIVES: The alternatives considered ranged from inaction to complete product replacement. The selection of complete replacement was made based upon the risk/reward analysis performed at the onset of the project. The decision to procure and design an entirely new solution better positions Avista for the future and mitigates more of the long-term risks associated with sunsetting technologies.

For instance, an alternative was considered to upgrade existing software (Wonderware) and develop new control screens (for $1,000,000). however, the risk was too great: maintaining the Wonderware product still posed a near-term risk to operations by continuing a relationship with an antiquated and unsupported product.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The project execution team (co-led by GPSS and ET PM resources) has established a draft implementation schedule which addresses the following high-level deliverables:

- Develop design standards and validate ET implementation plan – Summer 2021
- Complete GCC PLC Lab (Summer 2021) and Monroe Implementation (new projected ET completion date: Spring 2022) to provide GPSS and ET opportunities to test screen design and practice conversions in order to minimize impact to generating facilities and outage durations during site installation.

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known – see current schedule graphic in ”General Information” section.

- **Start Date:** 2018
- **End Date:** 2026

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/Governance Team

The need to address the risk of aging control software and outage control screens has been vetted through the Generation Production and Substation Support (GPSS) planning process.

The Controls Engineering Manager, along with the assigned Project Manager, will provide oversight and monthly tracking of the ongoing work within the project.

The Joint ET/GPSS Steering Committee will be comprised of the following members: GPSS Hydro Operations Manager, GPSS Thermal Operations Manager, GPSS Construction and Maintenance Manager, GPSS Manager of Project Delivery, ET Manager of Systems Engineering, ET Manager of Applications Delivery, ET Manager of Network Engineering.

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Project decisions will be made at the PM level where appropriate and escalated to the joint ET/GPSS Steering Committee when and if determined to be necessary. Regular updates will be provided to the Steering Committee by the PM team as project scope, schedule and budget are defined, and through the course of the project execution, change

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the HMI Control Software business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 12:35 PM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alexis Alexander EA27BABA767E467...	Date:	Aug-08-2023 | 12:59 PM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		
Signature:	NA	Date:	
Print Name:	NA; Alexis Alexander is on the steering committee for this project.		
Title:	NA		
Role:	Steering/Advisory Committee Review		

Coyote Springs 2 (CS2) Combustion Turbine Rotor Replacement

EXECUTIVE SUMMARY

PROJECT NEED: Coyote Springs 2 is a 280 MW combined cycle power plant located in Boardman, OR that provides both base load and variable generation as needed by Avista's Balancing Authority. The facility is owned by Avista and operated and maintained by Portland General Electric. Additionally, there is a Long Term Service Agreement (LTSA) with General Electric that covers most components on the Combustion Turbine and Generator, but not the replacement of the rotor at its normal end of life. The LTSA does cover replacement cost of a rotor that fails within its GE specified operational life (144,000 hours for the rotor currently in service). General Electric utilizes engineering, experience and best practices in the fleet to provide recommendations and guidance as to when certain pieces of equipment should be replaced or rebuilt to reduce the likelihood of equipment failures. For the Combustion Turbine Rotor, that recommended replacement is after 144,000 hours of operation. For Coyote Springs 2 the year we anticipate arriving at 144,000 operating hours, based on historical operational data, is 2026.

RECOMMENDED SOLUTION: Replace the Combustion Turbine Rotor

ALTERNATIVES CONSIDERED:

- Alternative 1: Exchange Rotor (100,000 hour run time)
- Alternative 2: Rotor Inspection & Repair

COST OF RECOMMENDED SOLUTION: $14,600,000

ADDITIONAL INFO: The replacement of the Coyote Springs 2 Combustion Turbine rotor at the GE recommended time will reduce the risk of unplanned failures that would cause a disruption in the electrical generation that supports the Bulk Electric System, and increase safety around the unit while in service.

Coyote Springs 2 (CS2) Combustion Turbine Rotor Replacement

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Mike Mecham	Initial draft of original business case	7/6/2021	
Draft	Mike Mecham	Reviewed	8/19/2022	
Draft 1.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
Draft 1.1	Mike Mecham	Updated spend table	5/10/2023	
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 4,170,0000	$ 0
2025	$ 10,430,000	$ 14,600,000
2026	$ 0	$ 0
2027	$ 0	$ 0
2028	$ 0	$ 0

Project Life Span	2 year
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Initiation
Category	Project
Driver	Failed Plant & Operations

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

Coyote Springs 2 (CS2) Combustion Turbine Rotor Replacement

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

A turbine is reaching it's defined "end of life." Utilizing experience and expertise with the fleet of their F Class Combustion Turbines, General Electric provides recommended guidance for periodic maintenance and/or replacement for many components on GE equipment, including Combustion Turbines. Coyote Springs 2 utilizes a GE 7FA combustion turbine that has a recommended replacement cycle on the rotor after 144,000 hours of operation. With recent annual average operating hours as guidance, Coyote Springs 2 is anticipated to reach 144,000 of operating hours in 2026.

1.2 Discuss the major drivers of the business case

The major driver for this project is Asset Condition and Failed Plant & Operations. The ability to keep Coyote Springs 2 in operation helps manage Avista's ability to provide reliable electricity and the lowest cost possible by giving Avista's System Operations and Power Supply departments the ability to utilize this asset when needed.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Using recent historical operating needs of Coyote Springs 2, the rotor replacement is projected to be required in 2026 as per GER-3620P (see section 1.5 below). A separate driving factor is the required maintenance on the remainder of the gas turbine parts not included in the rotor replacement. There is maintenance that is necessary every 32,000 fired hours. Coyote Springs 2 will reach this next benchmark of 32,000 hours in Q4, when the total fired hours reaches 138,000 in 2025 according to historical run hours. Should the 32,000 required maintenance hours trigger work in 2025, it will be the most cost effective practice to replace the rotor at that time although the rotor hours will be less than its 144,000 hours limit.

Recent historical operating hours on Coyote Springs 2:

2016 – 6,837

2017 – 6,465

2018 – 5,910

2019 – 7,410

2020 – 6,735

Avista and General Electric have a Long Term Service Agreement (LTSA) that covers the replacement and/or repair of many Combustion Turbine and Generator components. Within the Agreement, Avista pays GE an amount for each fired hour on the Combustion Turbine that is used to cover many major components repair and replacement on the Turbine/Generator, during the life of the LTSA. Two items to note: 1.) End of life replacement of the rotor is not covered under the LTSA conditions, although sudden failure is covered if such failure occurs within the recommended hours of operating life and 2.) If Avista chooses to defer the replacement of the Rotor past the GE recommended replacement guidelines, there may be exclusion to the remainder of the covered equipment. For instance, should Avista choose to defer the rotor replacement past the 144,000 hour GE recommendation, other parts typically covered under the LTSA may become ineligible if damaged due to a rotor failure or issue.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link***.**

Avista Strategic Goals

The purpose of this project is to provide funding to replace the Combustion Turbine rotor at Coyote Springs 2 and to ensure Coyote Springs 2 remains available to support the power needs of our company and our customers affordably. By doing this we support our mission of improving our customers' lives through innovative energy solutions which include Coyote Springs 2 generation.

The use of Coyote Springs 2 by Avista's Power Supply to provide the best value energy for Avista's customers. Coyote Springs 2 is able to provide efficient thermal energy and has been utilized an average of 6,670 hours per year over the past five years. Coyote Springs 2 is able to provide both Base Load generation and turn down ability, which allows Avista's Balancing Authority flexibility to reduce the plant generation without removing from service. If the rotor is pushed past its recommended life, and damage occurs due to failure, there would be a negative impact to Avista's customers.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.

Using recent historical operating needs of Coyote Springs 2, the rotor replacement is projected to be needed in 2025 as per GER-3620P (see section 1.5 below). Q4 2025 is the year we are projecting to be at the point of replacement needs due operating hours, which is the replacement guideline provided by GE.

Recent historical operating hours on Coyote Springs 2:

2016 – 6,837

2017 – 6,465
2018 – 5,910
2019 – 7,410
2020 – 6,735

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: The recommended alternative is to replace the Turbine Rotor when the operating hours reach 144,000. General Electric provided budgetary estimates for the below options: (Estimates provided by GE Service Manager Mark Brache on 4/30/2020). This will ensure Coyote Springs 2 continues to provide a reliable service to our customers.

In Scope: Complete replacement of the combustion turbine rotor by GE. The existing rotor will be removed and traded in for a discount. Includes stationery and rotating vanes, rotor shaft.

Out of Scope: Already covered equipment under the existing long term service agreement.

Assumptions: Contract not in place; there is a long-term service agreement in place for GE that handles maintenance items and provides direction. Assume GE equipment. No Avista craft labor required. Based on the past 5-year estimate of operating hours (see 1.3 above), it is estimated the in-service rotor will acquire 144,000 operating hours in 2026. The purchase and installation of a new rotor is projected to occur in Q2 of 2026, transfer to plant is projected to occur in June 2026.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[1]

- GE published "GER-3620P Heavy-Duty Gas Turbine Operating and Maintenance Consideration" in January of 2021. This is the most recent revision that outlines the "Maintenance Consideration" that include the replacement of the Combustion Turbine Rotor. Below is some text copied from GER-3620P that gives some of the GE guidance for rotor replacement:

  Rotor Inspection Interval Like hot gas path components, the unit rotor has a maintenance interval involving removal, disassembly, and inspection. This interval indicates the serviceable life of the rotor and is generally considered to be the teardown inspection and repair/replacement interval for the rotor.

Hours-Based Rotor Inspection

$$\text{Maintenance Interval (Hours)} = \frac{R}{\text{Maintenance Factor}}$$

$$MF = \frac{\text{Factored Hours}}{\text{Actual Hours}} = \frac{H + 2P^{(1)}}{H + P} \qquad \text{MF for B/E-class} = \frac{H + 2P + 2T_G^{(2)}}{H + P}$$

H = Non-peak load operating hours

P = Peak load operating hours

T_G = Hours on turning gear

R = Baseline rotor inspection interval

Machine	R[3]
FA.05 & HA Class	Refer to unit specific documentation.
F-class	144,000
B & E Class	200,000

(1) Maintenance factor equation to be used unless otherwise notified in unit-specific documentation.

(2) To diminish potential turning gear impact, major inspections must include a thorough visual and dimensional examination of the hot gas path turbine rotor dovetails for signs of wearing, galling, fretting, or cracking. If no distress is found during inspection or after repairs are performed to the dovetails, time on turning gear may be omitted from the hours-based maintenance factor.

(3) Baseline rotor inspection intervals to be used unless otherwise notified in unit-specific documentation.

Figure 44. Rotor maintenance interval: hours-based criterion

- Class 5 Estimate
- Risk Cost calculation from GPSS Asset Management Group: Risk cost is the product of the Failure Rate, Potential Consequence of failure, and the Probability of experiencing the potential consequence in the event of a failure. This risk cost is associated with the probable dollar value associated with Avista's exposure risk of each component. This exposure risk includes the cost of anything that threatens the company, including costs associated with a probable failure of the components (potentially including replacement, refurbishment, or lost generation costs), safety risks associated with normal operation or replacement actions, and probable environmental risks associated with the asset, and at times other costs such as public perception risk mitigation activities. While the company may not be able to shelter itself from risk completely, there are ways it can help protect itself from the effects of business risk, primarily by adopting a risk management strategy as a part of the asset management program. Risk costs not only take account for the exposure risk for an asset but also the criticality (or importance of an asset) and its' current condition. Risk costs are somewhat analogous to insurance

premiums. They represent an annual cost, but the year-to-year costs vary with the condition of the assets. If we total the risk costs for all of our assets for the next year, the company would need to have monies set aside for that year to cover the costs associate with the assets that fail that year.\

$$\begin{aligned}&Annual\ Risk\ Cost\\&= [Probability\ of\ Failure\ (that\ year)] \times [Consequence\ \$]\\&\times [Likelihood\ of\ actually\ experiencing\ that\ consequence]\end{aligned}$$

2.3 Summarize in the table, and describe below the DIRECT offsets[2] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

Estimated direct savings, inclduing hard cost savings, has not been quantified.

2.4 Summarize in the table, and describe below the INDIRECT offsets[3] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Equipment purchase in 2024, install in 2026	$0	$0	$18,612,000	18,612,000	18,612,000
O&M	NA	$0	$0	$0	$0	$0

OEM recommendations were considered. Additionally, PGE's unit 1 did have a rotor failure which resulted in a long outage. Depending on market conditions, power supply expense associated with such an outage could exceed 10's of millions of dollars for Avista's customers. Depending on the type of failure that could occur, personnel safety could also be at risk.

[2] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[3] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

A forced outage caused by a failed Gas Turbine Rotor could extend many months. The estimated daily Power Supply outage cost for this facility is $206,800 (refer to 20220825 Thermal Daily Outage Cost Estimation Tool CONFIDENTIAL.xlsx). Using an estimated 3 months for an emergency replacement, total Power Supply outage costs due to a failure is estimated to be: $18,612,000

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: The recommended alternative is to replace the Turbine Rotor when the operating hours reach 138,000, which will be in alignment with the next scheduled Major inspection for other major maintenance on the Combustion Turbine. General Electric provided budgetary estimates for the below options: (Estimates provided by GE Service Manager Zach Metcalf on 3/16/2023).

Alternative 1: Exchange Rotor (100,000 hour run time); $9,600,000

The exchange rotor option would be to remove the in service rotor and replace it with a rebuilt rotor that would be rated for 100,000 hours of operation. The rotor that was removed from service would be returned to GE. This alternative was not selected because of Avista's Integrated Resource Planning and Power Supply groups recommendation. The purchase of a new rotor reduces risk further in to the life of the facility. Note, all budgetary estimates are escalated 3.5% annually from the provided budgetary estimate for the next 5 years to allow for inflation.

Alternative 2: Rotor Inspection & Repair; $11,876,000

This option would be to inspect the Coyote Springs 2 in-service rotor and determine what type of repairs would be needed, then transport to a repair shop for rebuild. The un-escalated inspection cost is estimated to be $2,000,000 and the repair estimate is $6,000,000 - $8,000,000 depending on damage. Shop repair is estimated to be 3 – 5 months. This option is the least favorable due to the outage time needed for repair. Note, all budgetary estimates are escalated 3.5% annually from the provided budgetary estimate for the next 5 years to allow for inflation..

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Success will be measured by the continued safe, reliable and efficient operation of the 7FA gas turbine at Coyote Springs 2.

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known

- **Start Date:** 2024
- **End Date:** 2025

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/Governance Team

The Steering Committee for this project will consist of Thermal Ops & Maintenance Manager, Thermal Engineering and the Thermal Ops Manager

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the CS2 Combustion Turbine Rotor Replacement business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 12:34 PM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alexis Alexander EA27BABA767E467...	Date:	Aug-08-2023 | 1:13 PM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		
Signature:	NA	Date:	
Print Name:	NA; Committees have not been stood up at this time.		
Title:	NA		
Role:	Steering/Advisory Committee Review		

Nine Mile 3 & 4 Controls Upgrade

EXECUTIVE SUMMARY

PROJECT NEED: Nine Mile Units 3 and 4 controls were installed in the early 1990's and are at the end of their intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability. During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due their age and current condition. The switchgear floor is overloaded which poses a safety risk. In 2010, the switchgear floor was found to be inadequate for any loading above and beyond what it is currently supported, and partially replaced during the Unit 1 and 2 replacement project. The re

EXECUTIVE SUMMARY

PROJECT NEED: There are a multitude of mechanical issues with Nine Mile Unit 3. The original Unit 3 was replaced with a new American Hydro unit in 1995. Unit 3 experienced cracked buckets on the runners in 2010. This was found to be due to heavy wear due to erosion from sediment and cavitation damage. The cracks were repaired; however, the sediment wear has continued, and bucket failure is anticipated. The installed roller guide bearing also does not provide the thrust bearing support it was designed to, causing the upstream generator guide bearing to take the entire thrust loading of the machine. This condition puts increased stress and wear on the generator bearings and increases the risk of failure. During the 2018 Maintenance Assessment, this bearing was identified as high risk due to its current condition.

RECOMMENDED SOLUTION: The recommended solution is to mechanical overhaul the Unit including installing new Francis Runners, new downstream water lubricated bearing and pedestal, new combination thrust/guide bearing with thrust shaft, and refurbishment of the wicket gate stems and all operating components

ALTERNATIVES CONSIDERED:

- Alternative 1: Do-nothing and continue to repair the current system under O&M.

COST OF RECOMMENDED SOLUTION: The estimated cost of the project is $6,500,000

ADDITIONAL INFO: Operating Nine Mile safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES). This alternative would provide a lasting solution to the problems outlined above and avoid a costly unanticipated failure. If left unaddressed, the Unit is likely to experience bucket or bearing failure.

minder of the floor will need to be replaced to ensure adequate floor loading can be achieved.

RECOMMENDED SOLUTION: A controls upgrade including speed controllers (governors), voltage controls (automatic voltage regulator or AVR), primary unit control system (i.e., Unit PLC), and the upgraded protective relay system is needed on units 3 and 4. Included in the scope of this project is replacement of the switchgear floor inside the Nine Mile powerhouse that will be utilized for relocation of the unit controls and voltage regulation equipment.

ALTERNATIVES CONSIDERED:

- Alternative 1: One alternative considered is to replace the electrical equipment but not upgrade the floor.
- Alternative 2: A second alternative considered was to do-nothing

COST OF RECOMMENDED SOLUTION: The cost of the solution is estimated to be about $4,125,000 per unit at this time; total of $8,250,000.

ADDITIONAL INFO: The completion of this project will reduce maintenance costs and improve reliability delivered to Avista's customers as upgrading the controls, monitoring, and protection will reduce unplanned outages. This solution will address issues of obsolescence, increased likelihood of unplanned outages, and performance needs to work with the new dynamics of modern systems. This includes integration of intermittent resources, reserves, frequency and voltage response, and the ability to adapt these controls and protection devices as the larger grid continues to evolve. If this business case is not approved the risks above would continue as the asset condition continues to decline.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Kristina Newhouse Ryan Bean	Initial submission	7/2/2019	
2.0	Kristina Newhouse	Updated to 2020 template	7/31/2020	
3.0	Kristina Newhouse & PJ Henscheid	Updated to 2022 template and modified budget to align with improved estimates	8/23/2022	
4.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 2,100,000	$ 0
2025	$ 2,300,000	$ 0
2026	$ 2,250,000	$ 0
2027	$ 250,000	$ 8,250,000
2028	$ 0	$ 0

The business case will include 2 projects, one for Unit 3 and another for Unit 4. Design and Construction for each project take place over 3 years with the design of unit 4 starting during construction of unit 3. Each project with be transferred to plant at the completion of construction

Project Life Span	4 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Planning
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

The problem is that Nine Mile Units 3 and 4 controls are obsolete, unsupported and in overall poor condition; the switchgear floor is overloaded which is structurally unsafe.

1.2 Discuss the major drivers of the business case

The major driver of this business case is Asset Condition. There have been unit outages that were specifically taken to address problems associated with the existing control and protection equipment. Problems with the governor and wicket gate actuating mechanisms continue to affect unit reliability. The current governor system is undersized to handle the required load, causing startup and speed control issues.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due their age and current condition. This equipment is at the end of its intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability.

Upgrading the speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e., PLC), and the protective relay system will address issues of obsolescence, increased likelihood of unplanned outages, and performance needs to work with the new dynamics of modern systems. Also, the switchgear floor is inadequate to support additional loading for new equipment to be place. Replacing the remainder of the floor will ensure adequate floor loading can be achieved.

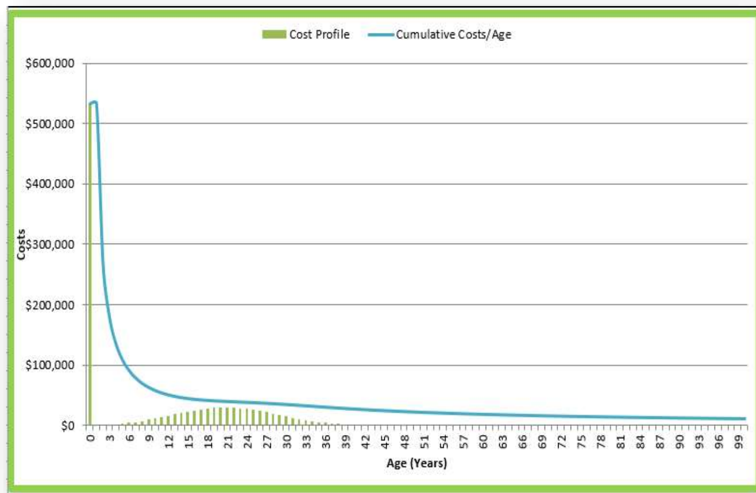
1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. Avista Strategic Goals

Replacing obsolete and problematic control equipment on unit 3 and unit 4 will increase reliability and efficiencies at Nine Mile HED. This program safely, responsibly, and affordably improves our customers’ lives through innovative energy solutions.

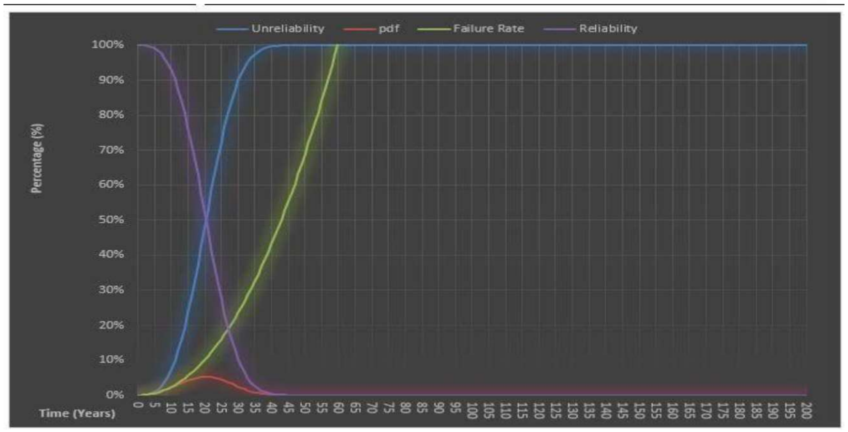
Customers benefit in that it will allow Avista to economically optimize an existing asset to provide energy and other energy related products.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due their age and current condition. This equipment is at the end of its intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability.



Please see the graphs which illustrate the Lifecyle Cost Analysis that was done as part of the 2018 Maintenance Assessment.



[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: The recommended solution is to replace unit control, monitoring, and protection systems, and it includes replacement of the switchgear floor to adequately support the new equipment to be placed. In addition to addressing issues of obsolescence and increased likelihood of unplanned outages, replacement of these key systems addresses the performance needs to work with the new dynamics of the systems today. This solution solves the problem described above through the integration of intermittent resources, reserves, frequency and voltage response, and the ability to adapt these controls and protection devices as the larger grid continues to evolve.

In Scope: The requested capital costs will cover design (contract labor), material, factory acceptance testing (contract labor), installation (AVA labor), and commissioning. To accomplish project objectives that will improve unit response, operating flexibility, and reliability, the following components will be considered: governor and governor controls, generator excitation system and AVR, protective relays, and unit controls, Unit 3 & 4 switchgear. The objective is to ensure system compatibility with current standards and improve system reliability. Flooring upgrades are limited to demo and reinforced (approx. half of the switchgear floor, ballpark 30'x50')

Out of Scope: Disassembling or pulling poles on the generators; generator work is limited to housekeeping**,** switchgear replacement.

Assumptions: Equipment will not be replaced in-kind: motor operated governor will be replaced with a hydraulic system; the current Bailey controls hardware will be replaced with a PLC; new Unit 3 & 4 switchgear will be relocated to the new switchgear floor (no modifications to the existing switchgear location will need to be made once the old switch gear is removed)

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- CARS (Capital Additions and Retirement) form which documents added and removed assets associated with Avista's facilities. This document helps Avista maintain accurate continuing property records.

- The 2018 Hydro Generation Condition & Risk Assessments, is referred to as the "2018 Assessment." Early 2018 GPSS-Hydro department undertook an initiative to revamp their maintenance programs. This included the 2018 Assessment, which was conducted in the hydro plants and incorporated both Risk Assessments and Condition Assessments. Teams consisting of representatives from the Mechanic, PCM Tech, and Electric Shops, as well as Spokane River Hydro, Clark Fork River Hydro, and Maximo teams were formed and tasked with performing a condition and risk based assessment for assets in all of Avista's hydro facilities. Additional details may be found in the "2018 Hydro Asset Management Program Directory". The full reference is provided below:

The Condition Assessments were based on the CEATI hydroAMP 2.0 guide. The database developed during the 2018 assessment has been used to create business information tools to identify and analyze equipment strategies to be used by GPSS for making business decisions.

The purpose of the Risk Assessment was to identify the environmental, financial, and safety risks associated with each asset and what possible consequences might result from an asset failure. Consequences were framed within the Avista Business Risk Matrix. Financial risks might include lost generation during an outage. Probabilities were then estimated as an answer to the following question: Given an asset failure, what is the probability that a particular, potential consequence will actually occur? As an aid to this process, probabilities were selected from a menu of specified probability levels. Results of the Risk Assessments have been used to estimate asset risk costs. Risk cost is the product of the Failure Rate, Potential Consequence of failure. This risk cost is a probable dollar value associated with Avista's exposure risk of each asset.

The results of the 2018 Assessment have been used to develop Asset Management Plans (AMPs) and a Risk Based Investment Planning (RBIP) tool. AMPs have been developed for a number of the asset classes, such as the generators, turbine runners, GSUs, trash rakes, etc. The AMPs outline capital and maintenance strategies. A primary purpose of the RBIP tool is to bring a risk-based perspective to the capital budget process.

Reference - Avista Utilities, "2018 Hydro Asset Management Program Directory", Avista Utilities GPSS Dept., March 15, 2019

Additionally, the following files from the 2018 Maintenance Assessment can be found at (c01m114) G:\Generation\Asset Management\GPSS Condition Assessment Forms and References\Condition Assessment - NM

1. Nine Mile Hydro AMP 041912.xlsx file
2. NM Lifecycle Cost Calculator 061918.xlsx

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

- Risk Cost calculation from GPSS Asset Management Group: Risk cost is the product of the Failure Rate, Potential Consequence of failure, and the Probability of experiencing the potential consequence in the event of a failure. This risk cost is associated with the probable dollar value associated with Avista's exposure risk of each component. This exposure risk includes the cost of anything that threatens the company, including costs associated with a probable failure of the components (potentially including replacement, refurbishment, or lost generation costs), safety risks associated with normal operation or replacement actions, and probable environmental risks associated with the asset, and at times other costs such as public perception risk mitigation activities. While the company may not be able to shelter itself from risk completely, there are ways it can help protect itself from the effects of business risk, primarily by adopting a risk management strategy as a part of the asset management program. Risk costs not only take account for the exposure risk for an asset but also the criticality (or importance of an asset) and its' current condition. Risk costs are somewhat analogous to insurance premiums. They represent an annual cost, but the year-to-year costs vary with the condition of the assets. If we total the risk costs for all of our assets for the next year, the company would need to have monies set aside for that year to cover the costs associate with the assets that fail that year.\

$$\begin{aligned}&\mathit{Annual\ Risk\ Cost}\\&= [\mathit{Probability\ of\ Failure}\ (\mathit{that\ year})] \times [\mathit{Consequence}\ \$]\\&\times [\mathit{Likelihood\ of\ actually\ experiencing\ that\ consequence}]\end{aligned}$$

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	N/A	$0	$0	$0	$0	$0

While the generator is capable of producing energy with existing systems, this solution requires maintenance of old systems that are no longer supported by the original manufacturer and there is some question on parts availability. Additionally, trained personnel available to work on these older systems are becoming scarce and formal training is no longer available. For reasons of obsolescence, inadequate system performance, and increasing maintenance demands, this option is not the preferred option. This project is a replacement of EOL technology and controls equipment that is no longer supported by

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

industry R&D and necessary support infrastructure to ensure reliable, affordable, and safe generation, production, and distribution of power.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	N/A	$0	$0	$0	$0	$0
O&M	N/A	$0	$0	$0	$0	$0

Estimated indirect savings and/or productivity gains and associated benefits have not been quantified at this time; however, as applicable, please see the referenced Risk Based Investment report (see Section 2.2) for additional information.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: The recommended solution is to replace unit control, monitoring, and protection systems and upgrade the switchgear floor. We cannot continue to operate units 3 and 4 at Nine Mile HED and expect the same results as when the controls were installed over 20 years ago. Technology has improved and the expectations for automation and monitoring continue to increase. The installation of new controls and protection will also provide increased visibility into the systems allowing better remote monitoring and troubleshooting. If we do not invest and take care of these two units, they will continue to be unreliable and fall further behind in technology that other upgraded units operate with.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Alternative 1: Replace Unit Control, Monitoring, and Protection Systems Only, Do Not Replacing Flooring; $7.25M

This Alternative would replace unit control, monitoring, and protection systems. This alternative would not upgrade the switchgear floor. This alternative is currently in engineering evaluation to determine if the new controls equipment can be functionally located somewhere other than the switchgear floor. There is still the potential that this alternative could be feasible, thus saving ~$1M in total project cost, but will not be determined until preliminary design is complete.

Alternative 2: Do Nothing; $0 in Capital

This alternative would leave the equipment as-is. Replacing the equipment is critical due to the extensive age of the various systems and the difficulty to upgrade only a portion of the technology as new technology is incompatible with the obsolete technology.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

A successful investment to upgrade the Nine Mile 3 & 4 Control Monitoring, and Protection systems would be measurable by Future Maintenance Assessments that would show an improved condition and reduction in risk,

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

The business case will include 2 projects, one for Unit 3 and another for Unit 4. Design and Construction for each project take place over 3 years with the design of unit 4 starting during construction of unit 3. Each project with be transferred to plant at the completion of construction

☒Timeline is Known

- **Start Date:** 2023
- **End Date:** 2025

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/Governance Team

The steering committee will minimally consist of the Controls Engineering Manager, the Electrical Engineering Manager, The Mechanical Engineering Manager, The protection Engineering Manager, the Protection Control Meter Technician Foreman, and the Spokane River Plant and Operations Manager.

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Nine Mile Unit 3 & 4 Control Upgrade business case the and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-09-2023 | 7:30 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alexis Alexander EA27BABA767E467...	Date:	Aug-26-2023 | 1:30 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		
Signature:	NA	Date:	
Print Name:	NA; Michael Truex is currently on the steering committee		
Title:	NA		
Role:	Steering/Advisory Committee Review		

Noxon Rapids Gantry Crane Modernization

EXECUTIVE SUMMARY

PROJECT NEED: Noxon Rapids construction was completed in 1959. Noxon has the capability of producing over 500 MW of peaking power. A key component of the facility is the gantry crane. The gantry crane is utilized to perform required maintenance and upgrades to the turbine/generators. The crane is rated for maximum lifting capacity of 325 tons. The gantry crane is now over 60 years old. Parts are difficult to source, and it does not conform to current safety standards. Past failures with the crane have caused delays in projects. A functional crane is equipment critical to completing future planned work including the Unit 2 Core and Winding Replacement, Excitation Replacement program work, the U3 Core and Winding Replacement, and U5 Turbine runner replacement. Without a functional crane, work cannot be performed. This could negatively affect generator availability which can have a negative impact on EIM performance.

RECOMMENDED SOLUTION: The recommended solution is to replace the existing gantry crane in-kind

ALTERNATIVES CONSIDERED:
- Alternative 1: Rehabilitate the existing crane
- Alternative 2: Do Nothing

COST OF RECOMMENDED SOLUTION: $19,080,000

ADDITIONAL INFO: Delays in work caused by degrading asset condition can be costly for Avista's customers. It is time to replace the Noxon gantry crane. If this project is delayed, continued operational costs will be experienced, and any safety or functional issues will not be mitigated into the future. Past failures with the crane have caused delays in projects.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Alan Lackner	Original Business Case	7/8/2020	Crane Modernization
2.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
3.0	Wendy Iris	Updates to BCJN	03/21/2023	Worked with Alan Lackner to update Business Case Justification
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2023	$ 2,000,000	$ 0
2024	$ 15,080,000	$ 0
2025	$ 2,000,000	$ 19,080,000
2026	$ 0	$ 0
2027	$ 0	$ 0

Project Life Span	3 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link.

Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

The problem being addressed is the Noxon gantry crane reliability, parts availability and safety. The Noxon crane has failed and caused significant delays in past projects. The crane controls and mechanical systems are becoming antiquated technology, unreliable, and it does not meet current crane safety standards. Parts, if available, are difficult to procure.

1.2 Discuss the major drivers of the business case

The driver for this business case is asset condition. In the past 60 years technology and safety standards for cranes have changed significantly. The reliability of the crane is becoming questionable during required maintenance activities. If a major failure occurs during required maintenance this could force a Noxon machine to be out for significant time frame, but even worse could cause catastrophic failure. This has the potential have a direct impact on customer rates and employee safety.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

A functional crane is equipment critical to completing future work Noxon Rapids HED has a maintenance plan that requires a reliable and safe crane; without a functional crane, this work cannot be performed. Reduced generator availability will have a negative impact on EIM performance.

Noxon has Unit 2 generator windings (2025 anticipated start date), C bank generator step up transformers replacement (2028 anticipated start date), Unit #5 turbine replacement (2027 anticipated start date), Unit 3 generator windings (2026 anticipated start date) and unit exciters starting in 2024 (anticipated start date) and annually until all 4 are replaced. Without a reliable safe gantry crane this work will not be able to be accomplished and generator availability will suffer.

The metrics supporting this modernization is personal safety, equipment safety and generator availability. Without a safe reliable gantry crane all of these have the potential to be negatively impacted.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. Avista Strategic Goals

Noxon Rapids affordably supports the power needs of our company and our customers. By taking care of this plant we support our mission of improving our customer's lives through innovative energy solutions which includes carbon-free hydroelectric generation. By executing this project, we ensure that Noxon Rapids is performing at a high level and serving our customers with affordable and reliable energy.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

- Parts are difficult to source, and it does not conform to current safety standards.
- The current condition of the crane and its subsequent impact on personal safety and generation availability are the primary drivers.

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: The recommended solution is to replace the existing gantry crane. This is a preferred alternative over rehabilitating the crane. Replacement of the existing equipment can give Avista the reliability and functionality needed.

In Scope: 325 Ton Gantry Crane Replacement

Out of Scope: Complete rail replacement/rehab

Assumptions: The current rail system can accommodate the loading needed for the new equipment; Plant manager would like would like to adjust the configuration to better access Unit 5 and auxillary equipment near unit 5.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- Lessons learned for the Cabinet gantry crane project have impacted the decision for crane modernization.
- CARS (Capital Additions and Retirement) form which documents added and removed assets associated with Avista's facilities. This document helps Avista maintain accurate continuing property records.
- Class 5 Estimate
- The 2018 Hydro Generation Condition & Risk Assessments, is referred to as the "2018 Assessment." Early 2018 GPSS-Hydro department undertook an initiative to revamp their maintenance programs. This included the 2018 Assessment, which was conducted in the hydro plants and incorporated both Risk Assessments and Condition Assessments. Teams consisting of representatives from the Mechanic, PCM Tech, and Electric Shops, as well as Spokane River Hydro, Clark Fork River Hydro, and Maximo teams were formed and tasked with performing a condition and risk based assessment for assets in all of Avista's hydro facilities. Additional details may be found in the "2018 Hydro Asset Management Program Directory". The full reference is provided below:

The Condition Assessments were based on the CEATI hydroAMP 2.0 guide. The database developed during the 2018 assessment has been used to create business information tools to identify and analyze equipment strategies to be used by GPSS for making business decisions.

The purpose of the Risk Assessment was to identify the environmental, financial, and safety risks associated with each asset and what possible consequences might result from an asset failure. Consequences were framed within the Avista Business Risk Matrix. Financial risks might include lost generation during an outage. Probabilities were then estimated as an answer to the following question: Given an asset failure, what is the probability that a particular, potential consequence will actually occur? As an aid to this process, probabilities were selected from a menu of specified probability levels. Results of the Risk Assessments have been used to estimate asset risk costs. Risk cost is the product of the Failure Rate, Potential Consequence of failure. This risk cost is a probable dollar value associated with Avista's exposure risk of each asset.

The results of the 2018 Assessment have been used to develop Asset Management Plans (AMPs) and a Risk Based Investment Planning (RBIP) tool. AMPs have been developed for a number of the asset classes, such as the generators, turbine runners, GSUs, trash rakes, etc. The AMPs outline capital and maintenance strategies. A primary purpose of the RBIP tool is to bring a risk-based perspective to the capital budget process.

Reference - Avista Utilities, "2018 Hydro Asset Management Program Directory", Avista Utilities GPSS Dept., March 15, 2019

- Risk Cost calculation from GPSS Asset Management Group: Risk cost is the product of the Failure Rate, Potential Consequence of failure, and the Probability of experiencing the potential consequence in the event of a failure. This risk cost is associated with the probable dollar value associated with Avista's exposure risk of each component. This exposure risk includes the cost of anything that threatens the company, including costs associated with a probable failure of the components (potentially including replacement, refurbishment, or lost generation costs), safety risks associated with normal operation or replacement actions, and probable environmental risks associated with the asset, and at times other costs such as public perception risk mitigation activities. While the company may not be able to shelter itself from risk completely, there are ways it can help protect itself from the effects of business risk, primarily by adopting a risk management strategy as a part of the asset management program. Risk costs not only take account for the exposure risk for an asset but also the criticality (or importance of an asset) and its' current condition. Risk costs are somewhat analogous to insurance

[2] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

premiums. They represent an annual cost, but the year-to-year costs vary with the condition of the assets. If we total the risk costs for all of our assets for the next year, the company would need to have monies set aside for that year to cover the costs associate with the assets that fail that year.\

$$Annual\ Risk\ Cost = [Probability\ of\ Failure\ (that\ year)] \times [Consequence\ \$] \times [Likelihood\ of\ actually\ experiencing\ that\ consequence]$$

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

Estimated direct savings, inclduing hard cost savings, has not been quantified.

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

Estimated indirect savings and/or productivity gains and associated benefits have not been quantified at this time; however, as applicable, please see the referenced Risk Based Investment report (see Section 2.2) for additional information.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: Rehabilitate the existing crane.

Alternative 1: Do Nothing; $0 Capital Cost

This alternative would continue to maintain the crane under O&M. This alternative was not selected because repair parts can be hard to source and the fact that the current crane controls and mechanical systems not meeting current safety standards.

Alternative 2: Rehabilitate the existing crane; $10M

This alternative is to rehabilitate the current crane. This alternative was not selected because the lessons learned from the Cabinet Gorge Crane rehabilitation project. The crane rehabilitation does not allow for increased functionality and changes in configuration; more specifically reaching components of Noxon #5. There is also a high dollar maintenance cost associated with rehabilitation to remove lead based paint, re-paint, and structural integrity repairs. The risk to Avista, if this alternative is selected, is that more money would be spent than likely needed.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The ability of the crane to be utilized during capitol and maintenance activities

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known: but no commitments have been made or actions taken to initiate delivery on the required timeline:

- **Start Date:** Would need to have a Design/Contractor/Manufacturer team in place by Q2 of 2023
- **End Date:** 2025

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

Steering Committee/Governance Team

Technical Team for input on Crane Performance:

- Dennis France; Larry Beeler; Doug Hutfles; Scott Renz;Gary Douglas; Jerry Heglie; Sean Kelley

Steering Committee

- Alexis Alexander; Alan Lackner; Greg Wiggins; Michael Truex; PJ Henscheid

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Noxon Rapids Gantry Crane 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:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 11:03 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		
Signature:	DocuSigned by: Alexis Alexander EA27BABA767F467...	Date:	Aug-28-2023 | 4:29 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

PROJECT NEED: The Post Falls HED started operation in 1906 and has been operating continuously since that time. The generators, turbines, and governors (turbine speed controller) are original equipment and are still in service. While the plant is still producing, the generating equipment, protective relaying, unit controls, and many other components of the operating equipment are mechanically and functionally failing. The turbines are estimated to be 50% efficient contrasted to modern turbines which can exceed 90% efficient. Because of the age of the plant, it presents some safety issues that have evolved over time including arc flash hazard to operating and maintenance personnel. The Post Falls Substation is also a wood station design and is in need of replacement. The Post Falls project is also subject to several critical operational requirements that support key recreational facilities, fishery, and other FERC license requirements.

RECOMMENDED SOLUTION: Post Falls HED be redeveloped by shutting down the plant, removing the old equipment, and replacing it in entirety with new. Included in this scoping effort was a needed substation replacement.

ALTERNATIVES CONSIDERED:

- Alternative 1: Relocate Plant GSU, and integrate into existing substation, with full substation rebuild within in the next 10 years

- Alternative 2: Rebuild substation in place. This includes substation specific IT project costs

- Alternative 3: Relocate and construct a new substation off the island prior to construction work on the powerhouse. This includes substation specific IT project costs

COST OF RECOMMENDED SOLUTION: The estimated cost of the project is $102,500,000 (+ 50% / - 30%).

ADDITIONAL INFO: The Post Falls project is subject to several critical operational requirements that support key recreational facilities, fishery, and other FERC license requirements. There is also a city Park and boat launch that is integral with the immediate upstream reservoir. Post Falls also supplies year-round base load hydroelectric power to Avista's portfolio. Continuing to operate Post Falls safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Steve Wenke	Initial draft of original business case	4/19/2017	
2.0	Jacob Reidt	Updated with Scope Increase	7/11/2018	
3.0	Ryan Bean	5 Year Planning 2020 & New Form	7/8/2020	
4.0	Ryan Bean	Annual Update	8/29/2022	Funding Managed outside of CPG
5.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
6.0	Greg Crossman	Annual update	DRAFT	Updated budget forecast
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 810,000	$ 0
2025	$ 5,100,000	$ 0
2026	$ 14,000,000	$ 5,000,000
2027	$ 29,000,000	$ 5,000,000
2028	$ 33,500,000	$ 0

$300,000 is anticipated to be spent in 2023; an additional $25,500,000 is anticipated to be spent in 2029; a total of $92,500,000 TTP anticipated to happen in 2029.

Project Life Span	8 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link. Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

The Post Falls HED started operation in 1906 and has been operating continually since that time. The generators, turbines, and governors (turbine speed controller) are original equipment and are still in service. The brick powerhouse with riveted steel superstructure is has not changed since the plant was constructed. Over time, it has been re-roofed and the intake area has had some major work performed, but the appearance of the project remains largely the same as when it started operation more than 110 years ago.

Photo showing interior of present Powerhouse

While the plant is still producing, the generating equipment, protective relaying, unit controls, and many other components of the operating equipment are mechanically and functionally failing. The turbines are estimated to be 50% efficient contrasted to modern turbines which can exceed 90% efficient. The existing governors have had patchwork repairs due to lack of replacement parts and while they do allow for unit control, they are ineffective in their response to system disturbances. Generator voltage controllers, protective relays, and unit monitoring systems all have a similar condition of marginal functionality.

The units are exhibiting signs of failure. Attached are recent reports for Unit 1, Unit 4 and Unit 6 that describe some of the problems encountered during the last maintenance on Unit 1, and the current operational directive to de-rate Unit 4 and Unit 6 due to their mechanical condition.

Because of the age of the plant, it presents some safety issues that have evolved over time. The access port for crews to access and maintain the turbine runners is too small to allow for any type of backboard or stretcher to exit the turbine area in the event a worker would be injured. The castings used to create the turbine water case do not allow the opening to be increased without risk of permanently damaging the water case and leaking. For this reason, crews can no longer access the turbines to maintain the runners. This has been the case for nearly a decade.

Photo showing safety issue due to restricted access to turbine area.

The opening will not allow a backboard or stretcher to the area for emergency evacuation.

Additionally, control modifications done in the late 1940's place the primary generator breakers inside the control room. This presents and unacceptable arc flash hazard to operating and maintenance personnel. While either the operation desk or the switchgear can be relocated to address this issue, this work would cost several million dollars and would not address some of the other issues associated with the plant.

Photo showing proximity of switchgear to Operators Station

(Operator Chair is indicated by arrow)

Finally, the Post Falls project has a number of critical operational requirements that support key recreational facilities, fishery, and other FERC license requirements. The Post Falls dam must provide minimum flows during summer months to support fishery habitat downstream. It is also subject to restrictions on how fast the flows through the project can change in order to meet downstream flow requirements. The present plant controls marginally provide the precision needed for this control.

To address water quality issues during high river flow seasons, unit and spillway controls must follow certain procedures to minimize Total Dissolved Gas creation in the river system. In addition, flows through the project provide water at the recreational site known as Trailer Park Wave. Upstream of the dam is the Spokane River and Lake Coeur d'Alene which are significant regional recreational resources that rely on the water control at Post Falls to maintain the water levels during the summer months.

Finally, there is a city Park and boat launch that is integral with the immediate upstream reservoir. Safety requirements have been implemented that require all spillgates at the project be closed before boaters are allowed to use the boat launch and recreate in the reservoir immediately upstream. Flows that would normally go through the plant need to be passed through the spillgates instead because of the unreliability of the generating units, extended maintenance outages, unit de-rates, and forced outages. This requires the boat launch opening to be delayed or in some cases closed on an emergency basis until flows subside or the generating unit can be returned to service.

Post Falls Substation is a wood station and is in poor condition due to proximity to the river. Two of the three breakers at the station are Westinghouse GM5A, 1957 vintage, some of the oldest in the system and a type of vintage that we have been anxious to replace across the system. One failed in 1993 and was replaced with an SF6 breaker. The Voltage Regulators are over 40 years old and the distribution reclosers are oil filled, both of which are driving factors for redevelopment of the substation within the near future. Work has not been done on the station historically due to difficulty of obtaining outages, which could be mitigated by working in conjunction with a plant rebuild.

1.2 Discuss the major drivers of the business case

The primary driver for this business case is Asset Condition; however, an increase in Performance & Capacity is also an anticipated outcome.

The Post Falls project is also subject to several critical operational requirements that support key recreational facilities, fishery, and other FERC license requirements. There is also a city Park and boat launch that is integral with the immediate upstream reservoir.

Post Falls supplies year-round base load hydroelectric power to Avista's portfolio. Continuing to operate Post Falls safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES).

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

Units continue to show signs of failure, impacting both generation and recreation on the Spokane River. Unit 6 has been removed from service and Unit 4 is de-rated. The substation is a wood structure and in need of replacement. Costs to repair or replace following an incremental approach would significantly exceed the cost of an encompassing redevelopment.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. **Avista Strategic Goals**

Operating Post Falls safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES). This work will replace the existing six 110 year old generating units with six new variable blade turbine generator units. Work will also include needed ancillary replacements and powerhouse remediation to attain a 50 year life project. In addition, the efficiency of the new generating equipment will result in an improvement in output capacity and energy. This project will result in an estimated 40% increase in capacity and 15% increase in energy and reduce future major maintenance costs.

By taking care of this plant we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Post Falls will continue to provide reliable service while mitigating unplanned failures.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.

1. Plant Operating Record and Restrictions
2. FERC License Conditions
3. Post Falls Assessment Study
4. Post Falls Feasibility Workshop Report
5. Post Falls Final Presentation
6. Post Falls Redevelopment Approval Summary
7. Post Falls Substation Asset Condition - (New)
8. Post Falls Redevelopment Substation Project Request - (New)

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: Operating Post Falls safely and reliably provides Avista's customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System (BES). This work will replace the existing six 110 year old generating units with six new more efficient turbine generator units. Work will also include needed ancillary replacements and powerhouse remediation to attain a 50 year life project. In addition, the efficiency of the new generating equipment will result in an improvement in output capacity and energy. This project will result in an estimated 40% increase in capacity and 15% increase in energy and reduce future major maintenance costs.

In Scope: Complete powerhouse rehabilitation including replacement of turbine and generator equipment, excitation, governors, and other electrical, control, and ancillary systems, supporting systems such as overhead cranes, control room reconfiguration, structural assessment and rehab as needed. Substation replacement including new GSU transformer relocated to within the new substation boundary.

Out of Scope: Spillway rehabilitation

Assumptions: The plant will be offline for the major powerhouse construction work. The new substation will be complete and available when powerhouse construction is complete.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[1]

- See Section 1.5

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

- The 2018 Hydro Generation Condition & Risk Assessments, is referred to as the "2018 Assessment." Early 2018 GPSS-Hydro department undertook an initiative to revamp their maintenance programs. This included the 2018 Assessment, which was conducted in the hydro plants and incorporated both Risk Assessments and Condition Assessments. Teams consisting of representatives from the Mechanic, PCM Tech, and Electric Shops, as well as Spokane River Hydro, Clark Fork River Hydro, and Maximo teams were formed and tasked with performing a condition and risk based assessment for assets in all of Avista's hydro facilities. Additional details may be found in the "2018 Hydro Asset Management Program Directory". The full reference is provided below:

  The Condition Assessments were based on the CEATI hydroAMP 2.0 guide. The database developed during the 2018 assessment has been used to create business information tools to identify and analyze equipment strategies to be used by GPSS for making business decisions.

  The purpose of the Risk Assessment was to identify the environmental, financial, and safety risks associated with each asset and what possible consequences might result from an asset failure. Consequences were framed within the Avista Business Risk Matrix. Financial risks might include lost generation during an outage. Probabilities were then estimated as an answer to the following question: Given an asset failure, what is the probability that a particular, potential consequence will actually occur? As an aid to this process, probabilities were selected from a menu of specified probability levels. Results of the Risk Assessments have been used to estimate asset risk costs. Risk cost is the product of the Failure Rate, Potential Consequence of failure. This risk cost is a probable dollar value associated with Avista's exposure risk of each asset.

  The results of the 2018 Assessment have been used to develop Asset Management Plans (AMPs) and a Risk Based Investment Planning (RBIP) tool. AMPs have been developed for a number of the asset classes, such as the generators, turbine runners, GSUs, trash rakes, etc. The AMPs outline capital and maintenance strategies. A primary purpose of the RBIP tool is to bring a risk-based perspective to the capital budget process.

  Reference - Avista Utilities, "2018 Hydro Asset Management Program Directory", Avista Utilities GPSS Dept., March 15, 2019

2.3 Summarize in the table, and describe below the DIRECT offsets[2] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Emergency replacement	$20M	$20M	$20M	$20M	$20M

[2] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

O&M	Emergency maintenance	$500k	$500k	$500k	$500k	$500k

The equipment at Post Falls HED is original to the plant, circa 1906. At over 110 years old, it is well past its design life. Continuing to operate the existing equipment will almost certainly result in increasing O&M costs to keep it operating, as well as increased capital costs as equipment becomes non-operational and unmaintainable. The greatest benefit to proceeding with this business case and completing the rehabilitation is that Avista has the opportunity to spend time designing the work and preparing for the outage. Alternatively, continuing to run the aged equipment would at some point result in an unexpected, unplanned outage, which would be far longer and more impactful than a planned outage. The potential costs above are estimated to suggest the significant impacts that an unplanned outage would cause in terms of emergency maintenance and emergency capital replacements.

2.4 Summarize in the table, and describe below the INDIRECT offsets[3] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	Unplanned outage	$++	$++	$++	$++	$++
O&M	-	$-	$-	$-	$-	$-

The cost of an unplanned outage would be substantial. Both the lost revenue associated with losing generation at an unexpected time for a sustained period, as well as the resulting operational costs of managing an inoperable plant, in addition to the cost of emergency planning and repair would be very high. There would also be reputational costs that are difficult to quantify, but would be significant with Post Falls being such a visible and vital part of the local communities and economies.

[3] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: Relocate and construct a new substation on the island prior to construction work on the powerhouse. This includes substation specific IT project costs.

Alternative 1: Relocate Plant GSU, and integrate into existing substation, with full substation rebuild within in the next 10 years; $2.5M+$10.6M (+/- 30%)

Alternative 2: Rebuild substation in place. This includes substation specific IT project costs; $11.75M(+/- 30%)

Alternative 3: Relocate and construct a new substation off the island prior to construction work on the powerhouse. This includes substation specific IT project costs ; $13M(+/- 30%)

At the request of Generation Production and Substation Support, the Engineering Roundtable (ERT) formed a sub-team to evaluate the current condition of the Substation, develop options, and propose a solution. Located in the GPSS files is a Post Falls Substation Asset Condition report demonstrating several key asset condition issues with the substation.

The substation team developed and evaluated four options, identified potential risks, and developed Rough Order of Magnitude Costs for each. Relocating the Substation off the island and rebuilding the substation in place were eliminated due to the risks of schedule delays for permitting, working around energized lines, and high probable costs were not offset by value.

The minimum viable option of relocating the GSU, and performing minimum upgrades would cost approximately $2.5 Million, with an expected additional spend of $10 Million in the near future. By coordinating a relocation of the substation with the plant redevelopment, the ERT and GPSS identified substantial risk reduction by minimizing exposure to high voltage lines during construction.

The sub team recommended, and the ERT approved, the further development of relocating and rebuilding the substation on the island due to considerations of asset condition issues, risks to the plant construction project, and best use of budget and resources based on a long-term view. This would require the use of contract resources (Commonwealth for design, contractor for construction) to minimize impact to existing ERT plan

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

The investment would be fielded in several phases over the course of six years. The design, procurement, and installation specifications of the new equipment would be overseen by a project team. The measure of success would consist of a successful commissioning of the equipment, with performance meeting the specifications, and providing reliable power generation with reduced O&M for years to come.

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known

- **Start Date:** 2023
- **End Date:** 2029

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

<u>The Steering Committee will consist of the following personnel:</u>

Bruce Howard, Senior Director of Environmental Affairs; Alexis Alexander, Director of Generation Production & Substation Support; Kevin Holland, Director of Energy Supply

<u>Oversight Process</u>

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight. Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Post Falls HED Redevelopment business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 10:41 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alexis Alexander EA27BABA767F467...	Date:	Aug-29-2023 | 4:13 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

Signature:	NA	Date:	
Print Name:	NA; Alexis Alexander is currently on the project steering committee.		
Title:	NA		
Role:	Steering/Advisory Committee Review		

EXECUTIVE SUMMARY

PROJECT NEED: The North Channel spillway at Post Falls is comprised of 9 total spillgates – one large rolling sector gate and 8 tainter style radial gates. The North Channel spillway is a critical asset to Post Falls, being that it is a main spillway to divert water downstream once plant capacity is reached. The North Channel spillway continues to show its age, with continuing concrete deterioration, failing mechanical gate hoist equipment, and gate issues. However, with all of these efforts, the current condition of the 110+ year old structure raises questions about its reliability to continue to provide the functions needed at the site.

RECOMMENDED SOLUTION: Following an engineering assessment process performed in 2021 utilizing an outside consultant firm, the recommended solution is to rehabilitate the tainter gates, modernize gate lift mechanisms, perform extensive concrete repair work, install a permanent emergency generator, and to either replace the rolling sector gate with 4 tainter gates OR perform a major rehabilitation of the rolling sector gate.

ALTERNATIVES CONSIDERED:

- Alternative 1: Do Nothing;
- Alternative 2: Baseline Rehabilitation
- Alternative 3: Replace Sector Gate with 4 Tainter Gates
- Alternative 4: Replace Sector Gate with 2 Crest Gates
- Alternative 5: Improved Aesthetic Flows

COST OF RECOMMENDED SOLUTION: Included with this assessment was a detailed project cost breakdown and estimate, and the project is estimated to cost $56,000,000 +50/-30% (AACE Class 4 estimate).

ADDITIONAL INFO: Post Falls is a critical piece of Avista's generating fleet. Fixing structural issues and ensuring the dam's integrity provide benefits to the customers such as continued generation and safety. Should this project continue to be delayed, any unplanned failure of this structure could be a serious and costly unplanned contingency in the Powerhouse Redevelopment. Of even more criticality is the economic and operational impacts to upstream, downstream, and aesthetics required of the project. Avista's river license could be affected and our relationship with state and federal regulators, in addition to the surrounding communities, would be in jeopardy should a portion of the spillway fail.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	PJ Henscheid	Format existing BC into exec summary	7.6.20	5-year Capital Planning Process
2.0	PJ Henscheid	Completion of full BCJN document	8.3.20	5-year Capital Planning Process
3.0	Greg Crossman/PJ Henscheid	Updated to 2022 template and modified budget to align with improved estimates	8.24.22	
4.0	Jessica Bean	Transfer to new BCJN Template	01/06/2023	No substantive changes/edits have been made to the business case through this transfer
BCRT	*BCRT Team Member*	*Has been reviewed by BCRT and meets necessary requirements*		

GENERAL INFORMATION

YEAR	PLANNED SPEND AMOUNT ($)	PLANNED TRANSFER TO PLANT ($)
2024	$ 10,500,000	$ 0
2025	$ 19,300,000	$ 5,000,000
2026	$ 21,000,000	$ 25,800,000
2027	$ 11,250,000	$ 31,250,000
2028	$ 0	$ 0

Design activities are slated to start in 2023 and extend into early 2024. Construction is anticipated to start as soon as possible in 2024, with considerations taken into spring run-off and water restrictions. Construction would continue into 2027.

There is anticipated to be portions of the project that would transfer to plant each year during construction, however the timing and amounts are unknown at this point in time due to the uncertainty of means and methods of an innovative contractor during construction.

Project Life Span	5 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Michael Truex | Alexis Alexander
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Project
Driver	Asset Condition

Definitions for the Category and Driver can be found on the Business Case Review Team Team's site see link. Investment Drivers

1. BUSINESS PROBLEM- *This section must provide the overall business case information conveying the benefit to the customer, what the project will do and current problem statement.*

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

The North Channel spillway is a critical asset to Post Falls, as it is a main spillway used divert water downstream once plant capacity is reached. The North Channel spillway continues to show its age, with progressing concrete deterioration, failing mechanical gate hoist equipment, and gate issues.

1.2 Discuss the major drivers of the business case

The major driver for this business case is asset condition. Improving the reliability and functionality of the gates will allow Avista to achieve, more reliably, it's river license requirements related to water flow from Post Falls HED.

1.3 Identify why this work is needed now and what risks there are if not approved or if deferred or risks being mitigated by the request.

The North Channel spillway will be critical to the success of the Post Falls Powerhouse Redevelopment, as likely all river flows for the duration of the project (up to two years) will be required to pass through it. Should a portion of the North Channel spillway fail to operate as needed during the powerhouse redevelopment project, there would be no certain way to pass flows and could result in uncontrolled flows over any one of the three dams (uncontrolled releases of water), flooding in Lake Coeur d'Alene, or a combination there-of.

In addition to normal maintenance activities, the North Channel Dam has undergone several major projects since the 1990's to keep it functional and reliable. These have included at least two grouting projects to attempt to improve the internal integrity of the primary dam. The large sector gate has been structurally modified to address some design deficiencies. The tainter gates have been painted, and lift mechanisms have been refurbished. However, with all of these efforts, the current condition of the 110+ year old structure raises questions about its reliability to continue to provide the functions needed at the site. The gate lift mechanisms are mechanically failing - the most recent failure mentioned above. The concrete supporting the eight tainter gates is also cracking due to loading where the gates pivot.

1.4 Discuss how the proposed investment, whether project or program, aligns with the strategic vision, goals, objectives and mission statement of the organization. *See link*. Avista Strategic Goals

This project will be highly important to the continued reliable and efficient operation of our Post Falls facility, and the Spokane River project. It will also help us maintain our relationships with our regulators and successfully implement our Spokane River license. Safe passage of water downstream through the facility, ensuring safety of not only plant personnel but that of the general public is of the utmost concern. The project will focus of the people responsible the delivering with a strong emphasis on performance. This nature of the project demands a collaborative environment with the wide array of key stakeholder groups.

1.5 Supplemental Information – please describe and summarize the key findings from any relevant studies, analyses, documentation, photographic evidence, or other materials that explain the problem this business case will resolve.[1]

- Prior to spring run-off of 2019, one of the gates' mechanical gear drives was irreparably damaged due, in part, to age of the gear train.
- The concrete condition is continuing to decline with large, localized spalls, leaking lift lines and construction joints.
- Seepage through the left abutment has also been monitored by the Dam Safety team for years.
- In addition to normal maintenance activities, the North Channel Dam has undergone several major projects since the 1990's in an attempt to keep it functional and reliable. These have included at least two grouting projects to attempt to improve the internal integrity of the primary dam. The large sector gate has been structurally modified to address its design deficiencies and the tainter gates have been painted, and lift mechanisms have been refurbished.
- Schnable Assessment Report—This engineering assessment was performed in 2021 to help Avista understand what is feasible at site. Final recommendations from the report led to the recommended solution outlined in this BCJN, with considerations (and analysis) related to risk (both upstream and downstream), engineering design and construction costs and complexities, and many other factors.
- The below table is from the Net Condition Index and Rating summary from the 2018 Hydro Generation Conditions & Risk Assessment. This information was compiled during the maintenance assessment of all Hydro assets performed in 2018. As shown, the condition of spillgates and hoists are rated as Fair to Marginal. However, the concrete was rated as Poor, and these concrete serves to withstand the hydrostatic force of the water on both the concrete and gates.

The condition indicators are dimensionless scores. A 3 is rating of good. On the bottom end, a 0 is poor. 2 and 1 are fair and marginal, respectively.

		Tainter Gate 1	Tainter Gate 2	Tainter Gate 3	Tainter Gate 4	Tainter Gate 5	Tainter Gate 6
Spillgates - N. Channel Tainter Gates	Marginal	5.17	5.17	5.17	6.17	5.17	5.17
Gates	*Fair*	6.67	6.67	6.67	6.67	6.67	6.67
Hoists	Marginal	4.17	4.17	4.17	6.17	4.17	4.17
		Sector Gate					
Spillgates - N. Channel Sector Gate	Marginal	5.17					
Gates		6.67					
Hoists		4.17					

Dam Concrete - N. Channel	Poor	1.0

[1] Please do not attach any requested items to the business case, rather be sure to have ready access to such information upon request.

2. PROPOSAL AND RECOMMENDED SOLUTION- *Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis).*

2.1 Please summarize the proposed solution and how it helps to solve the business problem identified above.

Recommended Solution: The recommended solution is to rehabilitate the existing Tainter gates and modernize their controls. The sector gate is recommended to be undergo a major rehabilitation, including modernization of the gate controls, or to be replaced with tainter style (or similar) gates to the other existing 8 gates. Installation of similar width gates across the spillway will allow for more flexibility in operations and maintenance and could allow the installation of dewatering features such as a bulkhead system that could be easily deployed from top of dam. The in scope/out of scope work will be finalized based on the selection of an alternative with the help of the Engineer of Record and Hill, an owners-engineer representative firm. The preferred alternative, to be determined later, will allow for reliable ongoing operation of the spillgate gates, and will provide more versatility and usefulness to the spillway.

In Scope: Gates, Concrete, Hoists, Lift Mechanisms, Electrical and Controls work. Extensive concrete work will be required regardless of the gate type due to the condition of the current concrete, up to and including full replacement of the spillway piers and spillway ogee. The embedded components (gate slots, guides and sills) will be refurbished if not replaced during the project pending their as-found condition and the gate replacement type. It is also recommended to incorporate a system such as stoplogs, embedded slots, and a dedicated monorail hoist to allow for future isolation and maintenance of the gates. A local, on-site emergency generator will be installed to ensure adequate and quick backup power to site.

Out of Scope: Embankment Work. Additional info is TBD, as of 01/2023.

Assumptions: The replacement gates are anticipated to be in-kind replacements, or through value engineering (VE) efforts could potentially be a more modern gate design, such as vertical rolling wheel gates or crest gates.

2.2 Describe and provide reference to CIRR/IRR analyses, relevant studies, documentation, metrics, data, analysis, risk reduction, or other information that was considered when preparing this business case (i.e., samples of savings, benefits or risk avoidance estimates; description of how benefits to customers are being measured; metrics such as comparison of cost ($) to benefit (value), or evidence of spend amount to anticipated return).[2]

- Avista's Dam Safety Surveillance and Monitoring Reports and Plans
- Schnable Report

- CARS (Capital Additions and Retirements) form which documents added and removed assets associated with Avista's facilities. This document helps Avista maintain accurate continuing property records.
- The 2018 Hydro Generation Condition & Risk Assessments, is referred to as the "2018 Assessment." Early 2018 GPSS-Hydro department undertook an initiative to revamp their maintenance programs. This included the 2018 Assessment, which was conducted in the hydro plants and incorporated both Risk Assessments and Condition Assessments. Teams consisting of representatives from the Mechanic, PCM Tech, and Electric Shops, as well as Spokane River Hydro, Clark Fork River Hydro, and Maximo teams were formed and tasked with performing a condition and risk based assessment for assets in all of Avista's hydro facilities. Additional details may be found in the "2018 Hydro Asset Management Program Directory". The full reference is provided below:

The Condition Assessments were based on the CEATI hydroAMP 2.0 guide. The database developed during the 2018 assessment has been used to create business information tools to identify and analyze equipment strategies to be used by GPSS for making business decisions.

The purpose of the Risk Assessment was to identify the environmental, financial, and safety risks associated with each asset and what possible consequences might result from an asset failure. Consequences were framed within the Avista Business Risk Matrix. Financial risks might include lost generation during an outage. Probabilities were then estimated as an answer to the following question: Given an asset failure, what is the probability that a particular, potential consequence will actually occur? As an aid to this process, probabilities were selected from a menu of specified probability levels. Results of the Risk Assessments have been used to estimate asset risk costs. Risk cost is the product of the Failure Rate, Potential Consequence of failure. This risk cost is a probable dollar value associated with Avista's exposure risk of each asset.

The results of the 2018 Assessment have been used to develop Asset Management Plans (AMPs) and a Risk Based Investment Planning (RBIP) tool. AMPs have been developed for a number of the asset classes, such as the generators, turbine runners, GSUs, trash rakes, etc. The AMPs outline capital and maintenance strategies. A primary purpose of the RBIP tool is to bring a risk-based perspective to the capital budget process.

Reference - Avista Utilities, "2018 Hydro Asset Management Program Directory", Avista Utilities GPSS Dept., March 15, 2019

2.3 Summarize in the table, and describe below the DIRECT offsets[3] or savings (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0

O&M	Depth of Maintenance required for gate operating systems	$0	$0	$0	$0	$0

Modern gate control mechanisms should reduce the depth of maintenance required at site. However, the amount of reduction of direct offsets due to this is difficult to determine at this point in time. Also, those offsets would likely not be realized until the systems are fully commissioned and used and useful

2.4 Summarize in the table, and describe below the INDIRECT offsets[4] (Capital and O&M) that result by undertaking this investment.

Offsets	Offset Description	2024	2025	2026	2027	2028
Capital	NA	$0	$0	$0	$0	$0
O&M	NA	$0	$0	$0	$0	$0

No discernible indirect offsets at this time

2.5 Describe in detail the alternatives, including proposed cost for each alternative, that were considered, and why those alternatives did not provide the same benefit as the chosen solution. Include those additional risks to Avista that may occur if an alternative is selected.

RECOMMENDED ALTERNATIVE: The recommended alternative is to rehabilitate the existing Tainter gates, replace the Sector Gate and gate lifting mechanisms, perform extensive concrete repair work, add a gate isolation system, update gate controls and repair or replace embedded components.

Alternative 1: Do Nothing; $0 Capital

This alternative was included for comparison purposes only, as it was determined early on that it was not viable due to the age and condition of the North Channel Spillway.

[3] Direct offsets are defined as those hard cost savings Avista customers will gain due to the work under this business case. Such savings could include reductions in labor, reduced maintenance due to new equipment, or other.

[4] Indirect offsets are those items that do not directly reduce the current costs of the Company, but may serve to reduce future hirings, improve efficiencies, reduces risk (cost or outage), or allows current employees to focus on higher priority work.

This option would not allow for addressing the concerns with the current condition of the spillway concrete or the gate operating mechanisms. This alternative will require continued and likely increased O&M costs as the gates continue to age. The major risk associated with this alternative is the unreliable operation and high risks should a structural member(s) fail and prevent the gate(s) from being operated, the mechanical drives fail, or the condition of the concrete continue to deteriorate.

Alternative 2: Baseline Rehabilitation; ($39,114,000)

This alternative includes significant concrete repairs, tainter gate rehabilitation, sector gate rehabilitation, improvement of aesthetic flows via discrete controls and proximity sensors, and electrical and controls improvements. For concrete repair, it was assumed that up to 18" of concrete would be demolished from exposed faces in order to place new concrete and fully encapsulate the existing concrete. This would be done at all tainter gate piers and spillway aprons.

The major risk with this alternative is continuing to operate the aging sector gate, which could act as a single point of major failure of the spillway should its operability become jeopardized because of the significant portion of flow controlled by only that gate. Other risks include challenges with refurbishing gates and concrete that are approaching 100 years old as well as the unknowns of the extent of the refurbishment needed. Improvements to aesthetic spill, or the method of performing aesthetic spill, is not fully necessary at this time.

Alternative 3: Replace Sector Gate with 4 Tainter Gates; ($13,697,000 in addition to the Baseline Alternative)

This alternative includes the baseline rehabilitation alternative but includes replacement of the sector gate with 4 equal sized tainter gates. This alternative allows for increased flexibility in operations of the gates and more finite control of the water flow through the facility. It also facilitates more effective dewatering capabilities at all of the gate locations, and reduces the risk associated with the Sector gate remaining in place.

Alternative 4: Replace Sector Gate with 2 Crest Gates; ($13,959,000 in addition to the Baseline Alternative)

This alternative includes the baseline rehabilitation alternative but includes replacement of the sector gate with 2 Hydraulically actuated crest gates. This alternative allows for increased flexibility in operations of the gates and more finite control of the water flow through the facility. It also facilitates more effective dewatering capabilities at all of the gate locations, and reduces the risk associated with the Sector gate remaining in place. The risks associated with Hydraulic fluid were discussed and considered when evaluating this alternative as well as the limited flexibility and continued complexity of dewatering these two gates for maintenance purposes.

Alternative 5: Improved Aesthetic Flows; $356,000 (in addition to the alternative chosen for the gates above)

This design alternative would include design and installation of a revised method to achieve the required aesthetic flows at North Channel Dam without use the of the tainter gates.

2.6 Identify any metrics that can be used to monitor or demonstrate how the investment delivered on remedying the identified problem (i.e., how will success be measured).

Successful completion of the North Channel Spillway Rehabilitation without issues related to flow would signify success. Also, more reliable and accurate gate operations at the North Channel, effective gate sealing, and reduced maintenance costs related to the concrete or gates would also signify success. Avista's federal and state regulators charge the company with maintaining water conveyance features at it's hydro facilities to ensure safety for both the public and the companies employees. Ensuring the spillways are fully functional and reliable not only allows for ease of use, but also helps ensure that we maintain the safety of the public, both upstream and downstream, of our facilities.

2.7 Include a timeline of when this work is scheduled to commence and complete, if known.

☒Timeline is Known

- **Start Date:** 2023
- **End Date:** 2027

☐Timeline is Unknown

2.8 Please identify and describe the Steering Committee/governance team that are responsible for the initial and ongoing approval and oversight of the business case, and how such oversight will occur.

<u>Steering Committee/Governance Team</u>

- Alexis Alexander – Director GPSS
- Scott Kinney – VP Energy Resources
- Bruce Howard – Senior Director Environmental Affairs

Oversight Process

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The steering committee will make impactful financial, schedule, or risk decisions related to project activities.

The project will also be executed by a formal Project Team lead by the Project Manager. Regularly cadenced steering committee meetings as well as monthly project reports with cost metrics assist in transparency and oversight.

Decisions, periodization efforts, and change requests will be tracked by the Project Manager for the project for the duration of project activities. These efforts will be entered into in conjunction with the project team and the steering committee members.

3. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Post Falls North Channel Spillway Rehabilitation business case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	DocuSigned by: Michael Truex 30401E01AC1543C...	Date:	Aug-08-2023 | 10:38 AM PDT
Print Name:	Michael Truex		
Title:	GPSS Manager of Project Management		
Role:	Business Case Owner		

Signature:	DocuSigned by: Alexis Alexander EA27BABA767F467...	Date:	Aug-28-2023 | 4:48 AM PDT
Print Name:	Alexis Alexander		
Title:	Director, GPSS		
Role:	Business Case Sponsor		

Signature:	NA	Date:	
Print Name:	NA		
Title:	NA; Alexis Alexander is currently on the project steering committee.		
Role:	Steering/Advisory Committee Review		