Bend In-conduit Hydropower Feasibilty Study Report

City of Bend, Oregon

City Project No. 1WHCD

January 2024

Jacobs

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Executive Summary

This report summarizes a feasibility study that evaluated potential locations for in-conduit hydropower generation within the City of Bend municipal water system. This effort was supported by the City's engineering staff and operations and maintenance (O&M) staff, and included input and analyses by other City consultants specific to water rights and water system hydraulics.

The Outback Water Filtration Facility (WFF) raw water pipeline was identified as a clear candidate for in-conduit hydropower due to high flows through existing energy dissipation facilities. In addition, other sites of opportunity within the water system were identified through a screening process that first reviewed locations with significant flow and pressure drop (typically through a pressure reducing valve [PRV]) and then reviewed daily flow patterns at these sites. The City's calibrated hydraulic model used for capital planning and system evaluation was used by the City's on-call water modeling consultant to perform these analyses. Through these analyses the initial eight candidate sites were screened to three sites that showed the greatest energy production potential. Thus, four in-conduit hydropower sites were identified for evaluation in this feasibility study as follows:

- Outback WFF raw water pipeline (Outback)
- Awbrey Reservoir PRV
- Athletic Club PRV
- Overturf Reservoir PRV

This assessment provides a basis for the City to consider whether to proceed with developing hydroelectric generation systems at the listed sites. The feasibility of in-conduit hydropower at each site was evaluated under three categories:

- Energy production potential (flow and available head)
- Technical feasibility (space constraints, equipment selection, utility connection, etc.)
- Economic applicability (generated power sale options, capital cost, and benefit-to-cost ratio over a 50-year planning period)

This report provides recommended next steps for each site should the City choose to proceed with implementation at candidate sites. Final determination of a project's feasibility must also consider the implication of a range of institutional factors, including any applicable Federal Energy Regulatory Commission (FERC) process, in-conduit hydroelectric water rights, utility interconnection, and site-related permitting. As described in this feasibility study, many variables affect economic feasibility. The benefit-to-cost ratio over a 50-year planning period was the criterion that was evaluated across many scenarios.

The study concludes the following:

- Two of the four sites evaluated in Section 3, Preliminary Site Assessment, are viable: the Outback site and Awbrey Reservoir site.

- The Outback and Awbrey Reservoir sites are both technically feasible.

- The Outback site is economically feasible (with a benefit-to-cost ratio greater than 1.0 over the 50-year planning period). If pursued, the anticipated benefits include offsets of existing power use, significant power sale revenue due to excess power generated above on-site demands, increased use of renewable energy, and improved resiliency against power failures caused by natural hazards and disasters.

- The Awbrey Reservoir site costs outweigh the benefits under all explored conditions to implement an in-conduit hydropower project at Awbrey Reservoir Site. . However, the study also found that maximizing all available incentives can increase the benefit nearly equivalent to the cost of the proposed project.

The study recommends the following actions:

- At the Outback site implement a single, dual nozzle horizontal Pelton turbine and generator. Pursue and implement "Partial Requirements" interconnection agreement with Pacific Power at the Outback site, with generator connected to new medium voltage switchgear as described in Outback Scenario 3 electrical configuration. This approach will realize resiliency benefits and maximize value of all power produced.

- At the Awbrey Reservoir site, implement two pump-as-turbine generation units, and upgrade existing electrical infrastructure. The existing electrical equipment is outdated at the Awbrey Reservoir site and unreliable, and good design practice recommends that it be replaced before making a new in-conduit hydropower connection. Establish a net energy metering agreement with Pacific Power.

- For all turbine/generator purchases, consider an evaluated bid equipment proposal including life-cycle costs, minimum performance standards, and power production performance testing requirements (including consideration of variable speed turbine[s] for Awbrey Reservoir site). Consider operating performance guarantees with incentives or penalties associated with meeting specified requirements in field testing after startup.

- Pursuing the recommended economic incentives and federal benefits is necessary to realize the economic feasibility of in-conduit hydropower at the Outback site. Pursuing additional incentive opportunities concerning the Awbrey Reservoir site may allow the overall benefit of the project nearly equivalent to the cost of the proposed project.

- Establish and maintain an in-conduit hydropower implementation schedule, including permitting and licensing. Permitting would include Deschutes County land use, Oregon Water Resources Department water rights, and FERC Qualifying Facility notice of intent to construct.

- Coordinate closely with the planned capital improvement projects at the Outback WFF and the ongoing design of the Awbrey Butte Waterline Improvements. These are essential to the future success of the projects. Specific risks for coordination include equipment and piping elevations, and physical layout of the facilities to coordinate with planned and future improvements. Coordination between all relevant parties will maximize power production, facilitate optimal O&M access, and integrate the proposed in-conduit hydropower facilities into the City's water filtration and distribution systems.

- Conduct a surge analysis to thoroughly examine the risks associated with normal and emergency shut down conditions of the hydropower generation at Outback site and Awbrey Reservoir site.

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Acronyms and Abbreviations

A	ampere
AIS	American Iron and Steel
ATC	automatic transfer controller
ATS	automatic transfer switch
BCR	benefit-to-cost ratio
BDC	Bend Development Code
BRIC	Building Resilient Infrastructure and Communities
cfs	cubic feet per second
City	City of Bend
CREP	Oregon Department of Energy's Community Renewable Energy Grant Program
DHAC	Division of Hydropower Administration and Compliance
DWSRF	drinking water state revolving fund
EL	Elevation
ETO	Energy Trust of Oregon
FCV	flow control valve
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
gpm	gallon(s) per minute
HGL	hydraulic grade line
HPU	hydraulic power unit
Hz	hertz
iWSMP	Integrated Water System Master Plan
kV	kilovolt(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
LVSWGR	low-voltage switchgear
MCC	motor control center
mgd	million gallon(s) per day
MVSWGR	medium-voltage switchgear
MW	megawatt(s)
NEM	net energy metering
NPDH	net positive discharge head

ODOE	Oregon Department of Energy
OPUC	Oregon Public Utility Commission
OWRD	Oregon Water Resources Department
O&M	operations and maintenance
PPA	Power Purchase Agreement
PPP	public-private partnership
PRV	pressure regulating valve
PURPA	Public Utilities Regulatory Policy Act of 1978
PV	photovoltaic
QF	qualifying facility
REC	renewable energy credit
rpm	revolution(s) per minute
SIPP	Sustainable Infrastructure Planning Project
SWBD	switchboard
USDA	U.S. Department of Agriculture
V	volt(s)
VAC	volt(s) alternating current
WFF	Water Filtration Facility

1. Introduction

This report summarizes a feasibility study that evaluated potential locations for in-conduit hydropower generation within the City of Bend municipal water system. The City's objective in performing this work is to evaluate the economic and engineering viability of constructing in-conduit hydroelectric facilities at the end of the raw water transmission line at the Outback Water Filtration Facility (WFF) and within the City of Bend water distribution system.

The study uses current and projected system operation information as well as current technologies to perform an in-depth economic analysis of the considered in-conduit hydropower facilities. This evaluation also investigated and reports federal and state incentives for the construction and operation of renewable energy facilities as well as all necessary permitting and licensing requirements for implementation of the considered in-conduit hydropower facilities. The study concludes with a recommended in-conduit hydropower configuration that is most opportune for the City of Bend and lays out the required process for implementation of the suggested in-conduit hydropower configuration.

1.1 System Analysis and Screening for Sites of Opportunity

This effort was supported by the City's engineering staff and operations and maintenance (O&M) staff, and included input and analyses by other City consultants specific to water rights and water system hydraulics. The Outback WFF raw water pipeline was identified as a clear candidate for in-conduit hydropower due to high flows through existing energy dissipation facilities. Other sites of opportunity within the water system were identified through a screening process that first reviewed locations with significant flow and pressure drop (typically through a pressure reducing valve [PRV]) and then reviewing daily flow patterns at these sites. (Note that in this study, the terms PRV and flow control valve (FCV) are both used. The valve bodies are physically identical and, when operated to sustain operator-selected flow rates, are referred to herein as FCVs) The City's calibrated hydraulic model used for capital planning and system evaluation was used by the City's on-call water modeling consultant to perform these analyses.

An initial screening summarized demand, groundwater supply and total control valve flow to each pressure zone for each season (summer, winter), and then also summarized summer season average daily flow through each control valve and the average headloss associated with each valve. The headloss associated with each control valve flow was estimated using a generalized operating hydraulic grade line (HGL) difference between the source zone and the zone supplied, and also with an average valve headloss computed within the hydraulic model under modeled seasonal operating conditions. Refer to the Consor valve flow modeling results provided in Appendix L.

Through these analyses the initial eight candidate PRV sites were screened to three sites that showed the greatest energy production potential. All eight sites are shown in Table 1-1, with Awbrey Reservoir, Overturf Reservoir, and Athletic Club sites being those with greatest energy production potential.

Table 1-1. Sites of Opportunity for In-conduit Hydropower Generation

Source: Consor Engineers, 2023a.

Valve name	Location	To water pressure zone	Summer average flow (gpm)	Average summer headloss (feet)	Average winter flow (gpm)	Average winter headloss (feet)	Average summer power (kW) *	Average winter power (kW) *
AWBREY_VALVE	Awbrey Flow Control	5	3,500	171	2,350	202	91	72
WAPRV044A	Mt. Washington and Archie Briggs	4F	704	108	264	130	12	5
OVER_FCV	Overturf Flow Control	4A	700	118	220	133	13	4
WAPRV038B	Athletic Club	4B	700	109	656	123	12	12
WAPRV040A	Archie Briggs and Falcon Ridge	5D	688	100	259	106	10	4
WAPRV041A	Archie Briggs and Silver Buckle	6	636	70	255	76	7	3
WAPRV005A	Purcell and Fullmoon	6	542	80	226	93	7	3
WAPRV009A	Boyd Acres and Ross	6	536	81	146	92	7	2

*Energy production generation assumes 80% turbine/generator efficiency.

gpm = gallon(s) per minute; kW = kilowatt(s).

From this initial screening, water system O&M staff reviewed and provided input suggesting that four sites be considered in more detail as follows:

- Outback WFF raw water pipeline. The site is a clear candidate for energy recovery, and has been identified by Energy Trust of Oregon (ETO) representatives as one of the highest statewide water system energy recovery opportunities. Existing electrical loads are available to consume power.
- Awbrey Reservoir PRV. Water operations result in consistent flow seasonally at similar hydraulic conditions. The site is a potential candidate for multiple turbines to maximize summer/winter performance. Existing electrical loads are available to consume power.
- Overturf Reservoir PRV. Water operations not as consistent as Awbrey Reservoir, but still viable for power production. Site location is behind fence on City-controlled property. Limited electrical load is available to consume power.
- Athletic Club PRV. Water operations not as consistent as Awbrey Reservoir, but still viable for power production. Site location in right-of-way. Limited electrical load is available to consume power. Potential for nearby public-private partnership to consume power at nearby commercial facilities.

The Mt. Washington/Archie Briggs PRV was expected to have similar features, costs, and benefits to the Overturf Reservoir site. It was not considered further as the Overturf Reservoir site had additional benefits of being located within a secure fenced enclosure.

These four locations of opportunity are shown in Figure 1-1.

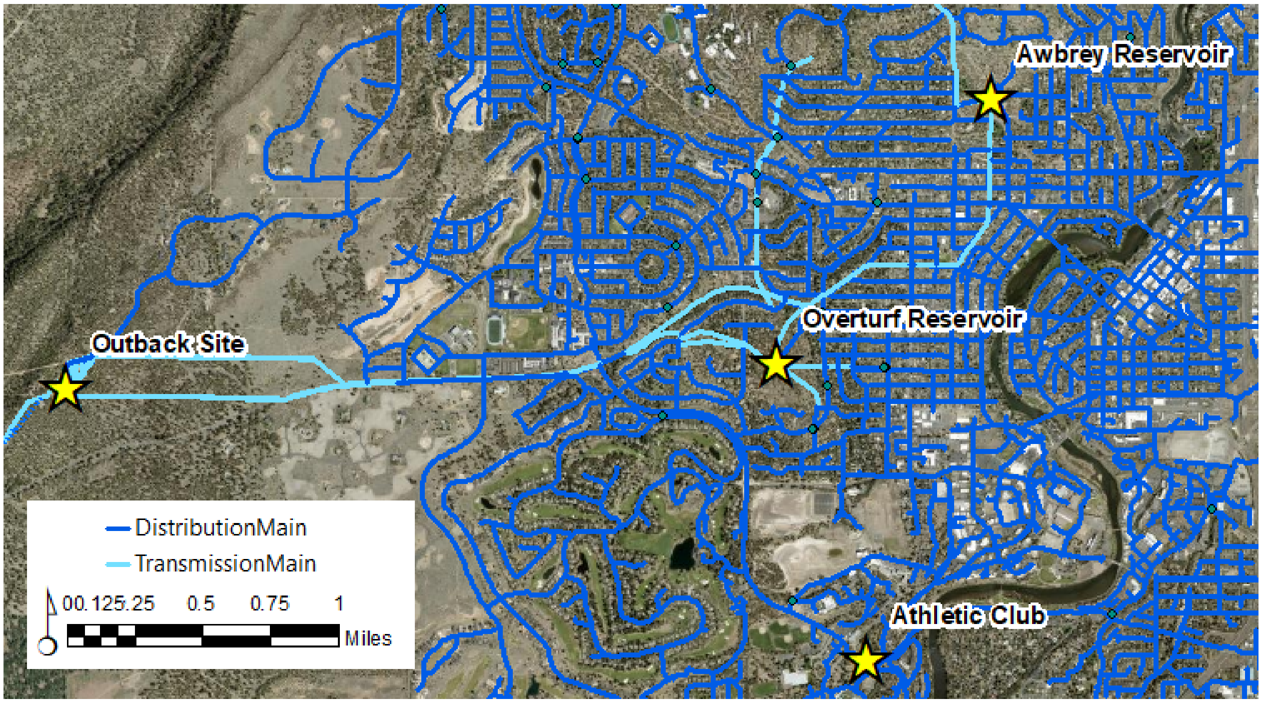

Figure 1-1. Feasibility Study Sites for In-conduit Hydropower in City of Bend, Oregon, Municipal Water System

1.2 In-conduit Hydropower Facility Requirements

In-conduit hydropower utilizes existing pipelines, irrigation canals, and other human-made water conduit structures as the basis for electricity generating equipment (U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, 2023). In-conduit hydropower projects generally exhibit limited or negligible environmental impact because they recover energy in a hydraulic system that is otherwise operating with energy dissipation or other operational control.

The Hydropower Regulatory Efficiency Act of 2013 established two pathways for implementation of in-conduit hydropower projects:

1. Qualifying Conduit Hydropower Facility - exempted from Federal Energy Regulatory Commission (FERC) permitting
2. Conduit Exemption – streamlined process from typical FERC application process

In-conduit hydropower projects, as are being evaluated in this study, would be considered qualifying facilities (QFs) and are exempt from FERC licensing.

A qualifying in-conduit hydropower facility means a facility (not including any dam or impoundment) that is not required to be licensed under Part I of the Federal Power Act because it is determined to meet the following criteria:

(i) Generates electric power using only the hydroelectric potential of a non-federally owned conduit;

(ii) Has an installed capacity that does not exceed 40 megawatts (MW); and,

(iii) Was not licensed or exempted from the licensing requirements of Part I of the Federal Power Act on or before August 9, 2013.

The Conduit Exemption process is not required or appropriate for the in-conduit hydropower projects being evaluated in this study because following this pathway would be more costly, require more work and time, and require additional consultation with federal agencies. Moreover, FERC has specifically developed the Qualifying Conduit Hydropower Facility designation to streamline implementation of projects like those the City is considering.

Water rights must be designated for all in-conduit hydropower energy generation. A hydropower generation right can be added to existing water rights for in-conduit hydropower through a defined process managed by Oregon Water Resources Department (OWRD). The City would make application to OWRD to add hydropower energy generation to each water right certificate, which would limit water use for hydropower to the season or conditions contained in the municipal water right. It is expected that both surface water and groundwater rights would be permitted with a hydropower energy generation water right and that no changes to existing water rights, including priority dates, points of diversion, or flows would occur.

1.3 Outback WFF In-conduit Hydropower Site Considerations

The City of Bend Integrated Water System Master Plan (iWSMP) (Murraysmith, 2021a) recommended that an in-conduit hydropower feasibility study be performed to develop current recommendations for in-conduit hydropower development at the Outback site. The Outback site was initially considered for in-conduit hydroelectric power generation potential during the Surface Water Improvement Project, which completed construction of a new raw water pipeline from the Bridge Creek Intake to the WFF in 2016. The City decided not to proceed with in-conduit hydroelectric generation at the Outback site in connection with the Surface Water Improvement Project and formally withdrew its draft application to FERC.

The raw water conduit to the WFF at the Outback site consists of approximately 9.5 miles of mostly 36-inch-diameter high-density polyethylene and 30-inch-diameter welded steel pipe. The conduit connects the City's surface water intake on Bridge Creek to the Outback site, with an elevation difference of approximately 1,017 feet. The flowing water at this elevation difference contains significant energy that is currently dissipated prior to the WFF using two 12-inch sleeve valves within the existing raw water control structure. Energy recovery through an in-conduit hydroelectric turbine was considered as part of the Outback Siting Study performed during the iWSMP (Murraysmith, 2021a) and basic conceptual layouts and hydraulic grade line exhibits were prepared demonstrating how such an in-conduit turbine could be connected within the planned future treatment process expansion, including pretreatment facilities ahead of the existing membrane filtration facility.

The City's water rights for allowable Bridge Creek diversions are based on several factors, but flows are limited to the demand for municipal use with a maximum of 18.2 cubic feet per second (cfs). Also, diversions are allowed all year and could be used in in-conduit hydropower generation after securing an in-conduit hydropower water right.

1.4 Distribution System In-conduit Hydropower Considerations

Water system operators have primary responsibility for delivering safe and reliable water supply to municipal customers in accordance with Oregon Health Authority requirements, while providing sufficient fire-flow capacity. Design of water system infrastructure is typically based on meeting these requirements. Retrofit of existing water distribution infrastructure to support in-conduit hydropower generation is best evaluated with broad understanding of system wide planning, site specific engineering requirements, and O&M needs. In addition to the Outback site, the City operates 147 pressure regulating valves (PRVs) and flow control valves (FCVs) throughout the water distribution system.

The City's water distribution system hydraulic model was updated to reflect significant planned transmission pipeline improvements current under design and construction upstream of Awbrey Reservoir and evaluated for this study by the City's on-call water modeling consultant. The model was used to identify locations that experienced a relatively high flow rate and substantial headloss. Sites were identified as preliminary locations of opportunity for in-conduit hydropower generation (Table 1-1. Sites of Opportunity for In-conduit Hydropower Generation

).

1.5 Feasibility Study Approach

This feasibility study presents an organized approach to evaluating in-conduit hydropower opportunities. The approach is as follows:

- Site assessment: site characteristics and equipment, selection, and capital cost estimates
- Identification of regulatory requirements, potential economic incentives
- Technical evaluation: equipment selection, site and facility layout, electrical configuration
- Economic evaluation: costs and benefits, including sensitivity analyses
- Recommendations

2. In-conduit Hydropower Assessment Background

In-conduit hydropower is a large untapped energy resource in the United States that has been identified by federal, state and local officials. The U.S. Department of Energy published a study (Oak Ridge National Laboratory, 2022) identifying 1.41 gigawatts of new generating capacity via in-conduit hydropower development in the municipal, agricultural, and industrial sectors across the United States. In Oregon, ETO is an agency dedicated to advocating for and financing incentives to promote energy efficiency, and energy recovery within Pacific Power and Portland General Electric service areas. ETO has supported City of Bend investments in energy efficiency and renewable energy and has specifically contributed to funding this study.

Oregon State University's Industrial Assessment Center (funded by U.S. Department of Energy 's Office of Energy Efficiency and Renewable Energy Advanced Manufacturing Office) has studied energy efficiency and power generation at the Outback site and has recommended implementation of in-conduit hydropower generation. The City's Community Climate Action Plan has proposed actions for Energy Supply including installing in-line hydropower system in the City water system.

Further, City of Bend City Council's 2021-2023 goals included implementing the City's internal Strategic Energy Management Plan including "pursuing opportunities for renewable energy generation, sustainable design, and resiliency" (City of Bend Council Goals, 2021-2023). The 2023-2025 Council goals specifically prioritized completion of this in-conduit hydropower feasibility study, and integrating greenhouse gas reduction strategies including decarbonizing the City's energy supply (City of Bend City Council Goals – 2023-2025).

Power output from an in-conduit hydropower turbine, regardless of size or type, is proportional to flow through the turbine and the headloss (or differential pressure) across the turbine. In principle, low-head/high-flow and high-head/low-flow conditions offer the same power and energy potential. The power formula for a hydraulic turbine generator is as follows:

$$\text{Power Output (kW)} = \frac{\text{Flow Rate (cfs)} \times \text{Net Head (feet)} \times \text{Turbine-generator Efficiency}}{11.82}$$

The energy produced in kilowatt-hours (kWh) equals the average power multiplied by the operating time in hours. Turbine equipment using large flows under low head is typically more costly per unit of power production than equipment operating under high heads at low flows. Further, optimal turbine performance is also based on operation under constant head. Depending on equipment type, a particular turbine is only effective when it operates over a certain range of flows and pressures higher and lower than the design operating point. Fluctuating head results in lower average efficiency and limitations in the operating range.

Critical considerations for an in-conduit hydropower generation facility installation within a municipal water system include the following:

- An in-conduit hydropower generation facility requires a means of automatic bypass to ensure continuity in water delivery should the turbine generator be shut down due to maintenance or emergency. A common bypass feature in a municipal water delivery system includes a PRV in parallel with an in-conduit hydropower turbine.
- Turbine generators will shut down under a variety of protective and operational conditions. Some shutdowns, like an electric utility outage, can occur regularly, and are considered part of normal operation. Shutdown of in-conduit hydroelectric equipment will result in transient flow conditions and these conditions will produce surge pressures in both upstream and downstream conveyance features. The capacity of the conveyance system to manage these surge pressures must be evaluated and design or operational approaches implemented to protect system from damage. These evaluations and mitigation measures must be part of final design of the project.
- Installation of in-conduit hydroelectric equipment will change the hydraulic profile (or HGL) by reducing the available pressure (head) in a facility's process stream. In a retrofit situation, the intent would be to maintain upstream and downstream pressures to match existing system conditions.

Water conveyance systems experiencing conditions of excess available head upstream of water treatment plants are common in mountainous regions such as Bend. Due to the relatively high cost of features associated with in-conduit hydropower production, such as permitting, utility interconnection (or the modification of a facility's electrical distribution system to accommodate onsite generation), and the modification of the conveyance features necessary to install the turbine, the conventional economic feasibility of these installations can be limited. However, capital, operating, and tax incentives, along with broader sustainability goals, can strongly influence overall feasibility.

3. Preliminary Site Assessment

Following screening to identify locations of opportunity, additional analyses were performed at the selected sites to evaluate the hydrologic (timing and magnitude of water flow volumes) and hydraulic characteristics (mechanical properties such as velocity, and pressure). These characteristics were shared with candidate turbine vendors for preliminary turbine/generator selection. Based on the selected equipment, the energy production potential of each site was calculated.

Several simplifying assumptions regarding flow, head, and other data are made in this initial evaluation, and these assumptions were validated by City of Bend water operations staff. The assumptions used in this assessment are deemed to be representative of typical operating conditions. An initial opinion of feasibility is formed based on preliminary data. The initial evaluation of site hydrology, net head, and interconnection considerations for each site are discussed in the following subsections.

3.1 Outback Site

The City's surface water supply is diverted at the Heidi Landsdowne Intake Facility, which contains the combined flows from Bridge Creek and natural springs in the Bend Municipal Watershed that are conveyed into Bridge Creek. The City's water rights consultant prepared detailed surface water diversion forecasts for a 50-year planning period based on the surface water demand between 2018 and 2022. Three alternative models were prepared to estimate how much surface water is available to the City and examine the influence of specific factors affecting water flow into the pipeline (i.e., raw water flow). Each model provides a time series of hourly raw water flow data, 24 hours per day, 365 days per year, from 2025 through 2075. Appendix I (GSI, 2023a) documents the flow projections in detail.

The three alternative models to estimate raw water flow in the Bridge Creek Pipeline and examine the influence of specific factors on raw water flow are as follows:

- Simple Model. Raw water flow is limited to a maximum of 18.2 cfs or to the City's projected water demand, whichever is less.
- Complex Model. In addition to the maximum flow limits of the Simple Model, the Complex Model considers the influence of indoor water conservation measures on demand, limitations on raw water flows during periods of low streamflow, and how surface water flows could be influenced by climate change. **This Complex Model was used as the basis of power generation estimates and all economic evaluations for the Outback site because the City and Consultant team agreed that it best represented a likely future water supply for feasibility study use and included effects of conservation and climate change**.
- No-Growth Model. This model is identical to the Complex Model but assumes no growth in water demands from the 2018 through 2022 baseline. This is intended as a sensitivity test to allow for evaluation of the specific influence of demand growth on projected raw water flow in the Bridge Creek Pipeline if desired.

The flow projections from 2025 through 2075 are factored based on 2020 conditions represented in Figure 3-1. This shows average daily demands and it is evident that summer demands always exceed the 18.2 cfs surface water system capacity, when groundwater sources are used to satisfy demand. Winter time surface water diversions are set by WFF operators in response to system demands. In the 2020 data presented below, winter demand is seen to be consistent across the season, which is typical for indoor water use. Each of the three models evaluates a total system demand forecast for the time step, and then determines if surface water rights can satisfy that demand. If not, the surface water demand is limited to the available water right. This is done for each timestep for each year in the forecast, and then power production calculations are performed for each timestep.

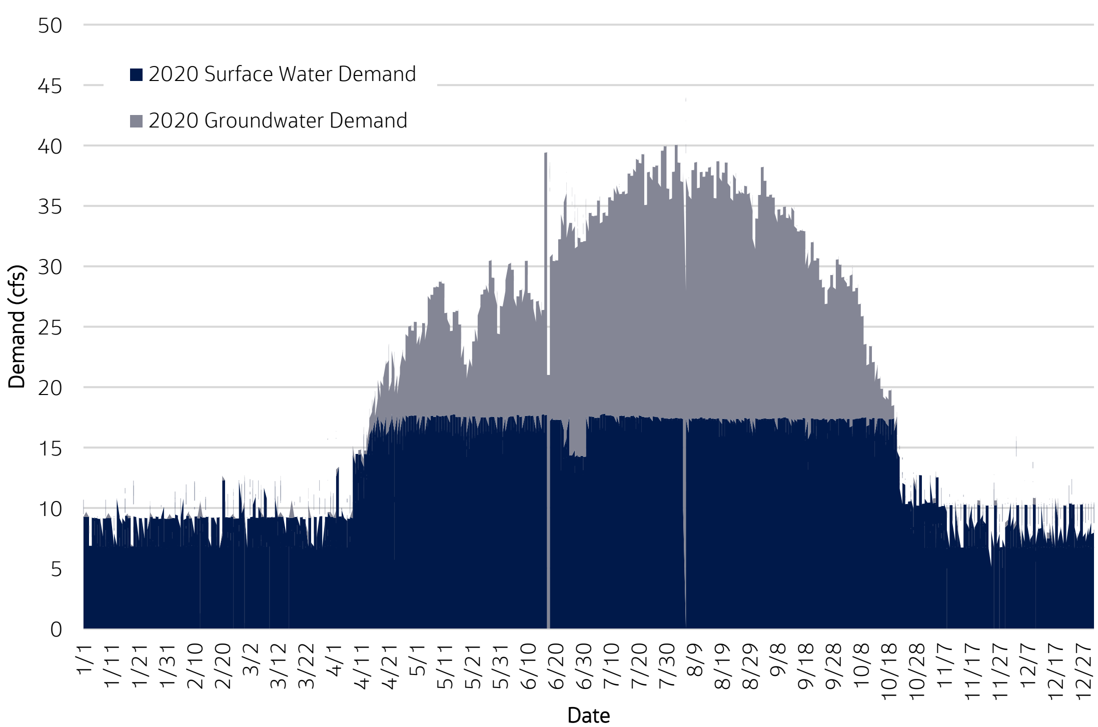

Figure 3-1. City of Bend Hourly 2020 Surface Water and Daily Average 2020 Groundwater Demands

Source: GSI Water Solutions, Inc. 2023a

Figure 3-1 shows typical seasonal annual waster demand from surface water and groundwater sources at the Outback site. Appendix I details the City's surface water rights. The time series flow projections from the Complex Model address the terms of the water rights (including priority date, diversion rate, authorized annual volume, and timing limits).

The City's diversion is currently limited to a maximum of 18.2 cfs by Special Use Permit BEN1178 issued by the U.S. Department of Agriculture (USDA) Forest Service, as well as by the City's Municipal Code (Section 14.10.090). This diversion limit can be seen as the summer time (approximately May through October) maximum surface water demand in Figure 3-1. The City's surface water supply can be further limited by streamflow, the requirement to share Tumalo Creek water supply with water right holders of similar priority date, surface water quality events, system capacity, and periodic system shutdowns for maintenance. Consistent with state and federal permitting requirements, no additional streamflow can be diverted for generation of hydropower beyond what is authorized and used to meet the City's municipal demands. Water right permitting requirements for in-conduit hydroelectric facilities are discussed further in Section 3.3.

Typical historical and projected surface water diversions to the Outback site range between 5 to 18.2 cfs depending on system demand. When the WFF is offline, and when surface water diversions are insufficient to meet system demand, the City operates groundwater wells to satisfy demand. The wells at the Outback site discharge downstream from the WFF and will not flow through the turbine at the Outback site. The static head at the Outback site is 1,017 feet (turbine centerline elevation assumed at Elevation [EL] 4,003.39 feet). Headloss across the flow control structure varies as a function of the flow as shown on Figure 3-2. Turbine vendors use this characteristic curve to confirm equipment selection.

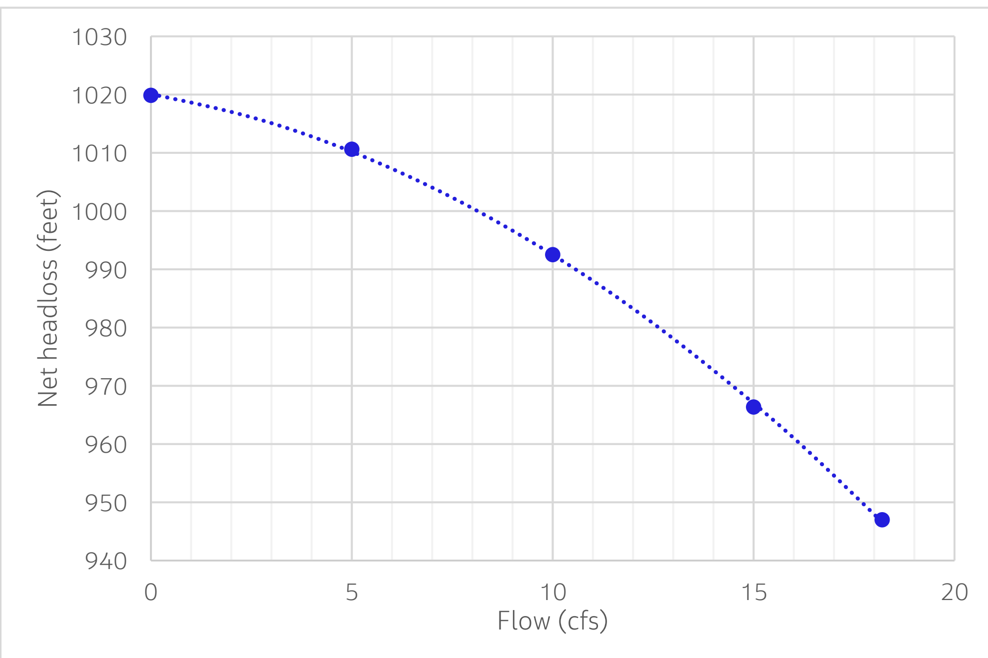

Figure 3-2. Surface Water Demand Flow Versus Net Head for Hydropower Turbine at Outback Site

Source: Murraysmith, 2021a

Based on the flow characteristics of the Outback site, Jacobs solicited vendor proposals for turbine, generator, and related equipment from major industry suppliers for Pelton-style turbines. Four vendors submitted proposals, including equipment model selection, general arrangement drawings, and budgetary cost proposals:

- Canyon Hydro
- Gugler

- Mavel
- Andritz

A summary of these vendor responses is shown in Table 3-1. The vendor contact information is listed in Appendix E. All vendors recommended dual-nozzle Pelton turbines with horizontal rotational axes for the Outback site. Each vendor was asked to include electrical and control equipment capable of operating the generation system while disconnected from the offsite electrical grid, as might occur during a major disaster; for instance, a Cascadia Subduction Zone earthquake that could potentially cause extended electrical grid disruption. This grid-independent operation is known as "isochronous" or "island" mode in the industry.

Table 3-1. Outback Site Vendor Response Summary

Vendor name (corporate location)	Power production estimate (MW)	Energy production estimate for 2025[a] (kWh)	Budgetary equipment cost[b] (U.S. dollars)
Canyon Hydro (State of Washington, USA)	1.2 MW	8,1,37,000 kWh	$1,113,575
Gugler (Austria)	1.3 MW	8,729,000 kWh	$1,031,733[c]
Mavel (Czech Republic)	1.3 MW	8,661,000 kWh	$995,000
Andritz (Austria)	1.3 MW	8,721,000 kWh	$1,523,275[c]

[a] 2025 annual energy production estimate while accounting for a 2-week annual off-line maintenance period.

[b] Equipment cost only. Received budgetary quotations are comparable and within the same order of magnitude. However, each vendor's contract terms, and details of the offerings are different. Refer to vendor quotations for further information in Appendix A. Equipment cost does not include civil, structural, or other construction costs.

[c] Quotes are submitted in Euros. Exchange rate of 1.09 U.S. dollars/Euro is used.

During final design of an in-conduit hydropower facility, specific vendor offerings should be evaluated to consider life-cycle cost, efficiency, and other factors. For the purposes of this feasibility study, Canyon Hydro's proposed budgetary cost estimate, power production estimate, and equipment layout were used as the basis for the assessment due to vendor responsiveness, consultant experience, and long established factory location in the Pacific Northwest nearest of all vendors to the City of Bend. Section 5.1 includes a description of the Outback site's technical feasibility assessment for in-conduit hydropower potential.

3.2 Awbrey Reservoir Site

The flow of water into Awbrey Reservoir is currently regulated by an FCV. An important feature that makes the Awbrey Reservoir site attractive for in-conduit hydroelectric energy recovery is the generally consistent flow throughout winter demand and maximum demand seasons with a relatively small variation in headloss as shown on Figure 3-3 and Figure 3-4. The City is currently designing and constructing improvements to the Awbrey Transmission Main, which will be complete in the next few years, with a goal to increase hydraulic conveyance from the Outback WFF to Awbrey Reservoir. The improvements include a new 30-inch-diameter pipeline and new FCV controlling flow into Awbrey Reservoir.

The City's water system hydraulic model was modified by the City's on-call water modeling consultant to include the new hydraulic conditions, and then evaluated using an extended period simulation model. This extended period simulation accounts for normal operation in summer and winter, and incorporates expected variation in the Awbrey Reservoir level that will affect available net head for energy recovery. A 72-hour diurnal flow versus headloss curve was prepared to project winter and summer flow conditions once the new transmission main is operational.

It was assumed that the 72-hour period represents typical conditions for 6 months for each season, summer and winter. This is a reasonable simplifying assumption to facilitate the feasibility study. The operation scheme where a relatively constant flowrate is experienced seasonally at Awbrey Reservoir is particularly suited for assumptions of typical operation for 6 months winter and 6 months summer.

This feasibility study focuses on the hydraulic characteristics of the Awbrey Reservoir site, but some coordination has taken place on in-conduit hydropower facility layout with the design of transmission main improvements being prepared others. Detailed design of the in-conduit hydropower generation facility must closely coordinate with the final design and as-built improvements at the site. Figure 3-3 and Figure 3-4 show that seasonal water demand at Awbrey Reservoir inlet was constant throughout the 72-hour extended period simulation. The variation in net head in the summer conditions is representative of the varying water surface in Awbrey Reservoir caused by summer time system demand that draws down the reservoir elevation and volume to meet daily diurnal demand. No significant net head variation occurs during the winter season as daily diurnal demand fluctuates less.

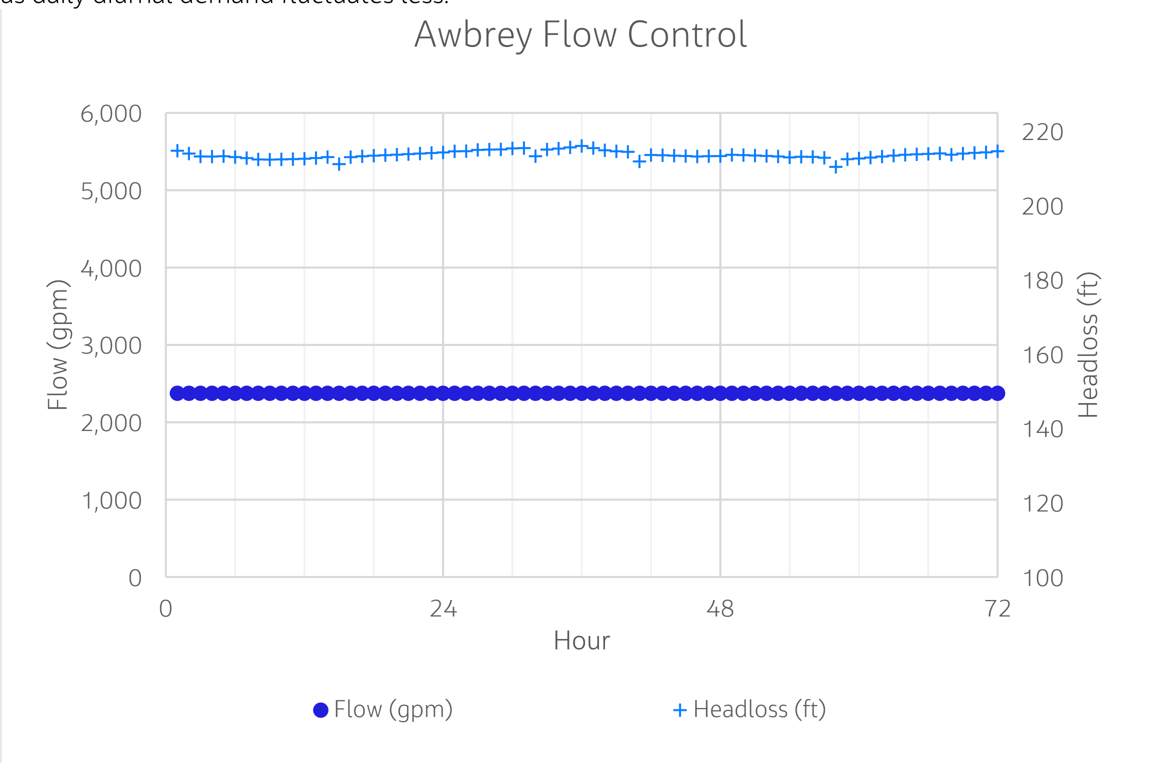

Figure 3-3. Awbrey Reservoir Site Winter Demand Over 72-hour Period

Source: Consor Engineers, LLC, 2023b

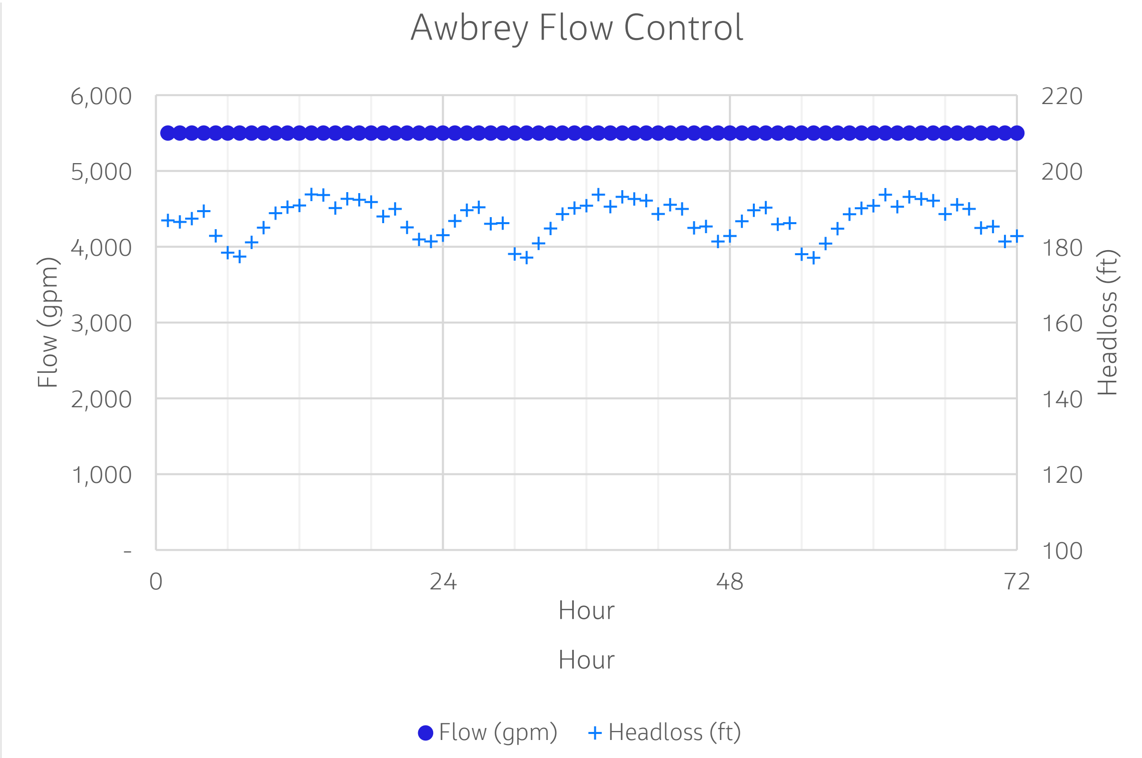

Figure 3-4. Awbrey Reservoir Site Maximum Demand over 72-hour Period

Source: Consor Engineers, LLC, 2023b

Based on the flow characteristics at the Awbrey Reservoir, Jacobs solicited hydropower vendor input. Two vendors, Canyon Hydro and InPipe Energy, submitted budgetary quotations. The summary of vendor responses is shown in Table 3-2. Canyon Hydro proposed two identical turbine units (Cornell 5 TR4; constant speed model), whereas InPipe Energy proposed a single turbine unit installation of HydroXS-M12 (variable speed model).

Table 3-2. Awbrey Reservoir Vendor Response Summary

Vendor name	Proposed turbine	Power production estimate (Winter/Summer, kW)	Energy Production Estimate (kWh/year) [a]	Budgetary equipment-only cost [b]
Canyon Hydro (U.S. based)	(2) parallel Cornell 5TR4, single speed [c]	59 /87	612,000 kWh/year	$266,000
InPipe Energy (U.S. based)	Single unit installation of HydroXS-M12, variable speed	51/136	765,000 kWh/year	$301,500

[a] Energy production estimate is made while accounting for a 2-week annual off-line maintenance period.

[b] Each vendor's contract terms, and equipment offerings are different. Refer to vendor quotations for further information in Appendix B. Equipment cost does not include civil, structural, or other construction costs.

[C] Power production based on one unit operational in winter, and two in summer.

During final design of an in-conduit hydropower facility, specific vendor offerings should be evaluated to consider life-cycle cost, efficiency, and other factors. For the purposes of this feasibility study, Canyon Hydro's proposed budgetary cost estimate, power production estimate, and equipment layout were used as the basis for the assessment due to vendor responsiveness, consultant experience, and long established factory location in the Pacific Northwest. InPipe is based in Portland. Section 5.2 includes a description of the Awbrey Reservoir's technical feasibility assessment for hydropower potential.

3.3 Athletic Club Site

The flow at the Athletic Club Site is currently regulated by a PRV. The existing facilities are located adjacent to Reed Market Road within the right-of-way. All water pipes and valves are located in a below-grade vault with above-grade control panel. The City has no significant electrical demand at the site that could be offset by power production, which is a disadvantage for the site. The Athletic Club PRV experiences a zero-flow period in both winter and maximum demand seasons, as shown in Figure 3-5 and Figure 3-6. A 72-hour flow versus headloss curve was prepared to project winter and summer flow conditions.

It was assumed that the 72-hour period represents typical conditions for 6 months for each season, summer and winter. This is a reasonable simplifying assumption to facilitate the feasibility study.

From a hydraulic perspective, it would be possible to implement energy recovery along this pipeline at any location east of the existing pipeline along Reed Market Road to near Brookswood Boulevard. However, costs for such construction at an alternate acceptable hydraulic site nearby would likely exceed costs at the existing Athletic Club PRV site, where existing PRV and control panel infrastructure could be reused. Such locations were not considered in this study. If a source to consume the generated power from an Athletic Club site generator could be implemented through a public-private partnership (for a power customer adjacent to the pipeline with significant electrical demand) greater benefits could be realized than from the City's limited power demand at the site.

Similar to the Awbrey Reservoir site, two vendors provided budgetary quotations for candidate equipment at the Athletic Club site (Table 3-3). Vendor responses are summarized in Appendix B (InPipe Hydro budgetary quotation) and Appendix C (Canyon Hydro budgetary quotation). The estimated power production of the two offerings is similar but the cost proposals are not comparable due to different equipment scopes included. Canyon Hydro's proposed budgetary cost estimate, power production estimate, and equipment layout were used as the basis for the assessment due to vendor responsiveness, consultant experience, and long established factory location in the Pacific Northwest. InPIpe is based in Portland.

Figure 3-5 and Figure 3-6 show that seasonal water demand at Athletic Club PRV site varies considerably throughout the 72-hour extended period simulation. In the winter season there are periods of zero flow, and diurnal flows vary from 400 to 1,100 gpm. Constant speed turbines for "pump as turbine" applications like this are designed for a single flow rate, and so this site is not well suited for in-conduit hydropower, unless either a variable speed turbine was provided, or in-conduit hydropower generation was operated for only optimal flow conditions, which would reduce the power production and cost/benefit metrics. In the maximum demand season, flow varies significantly, including periods of zero flow and variable head due to diurnal fluctuations in system pressures due to reservoir draw down.

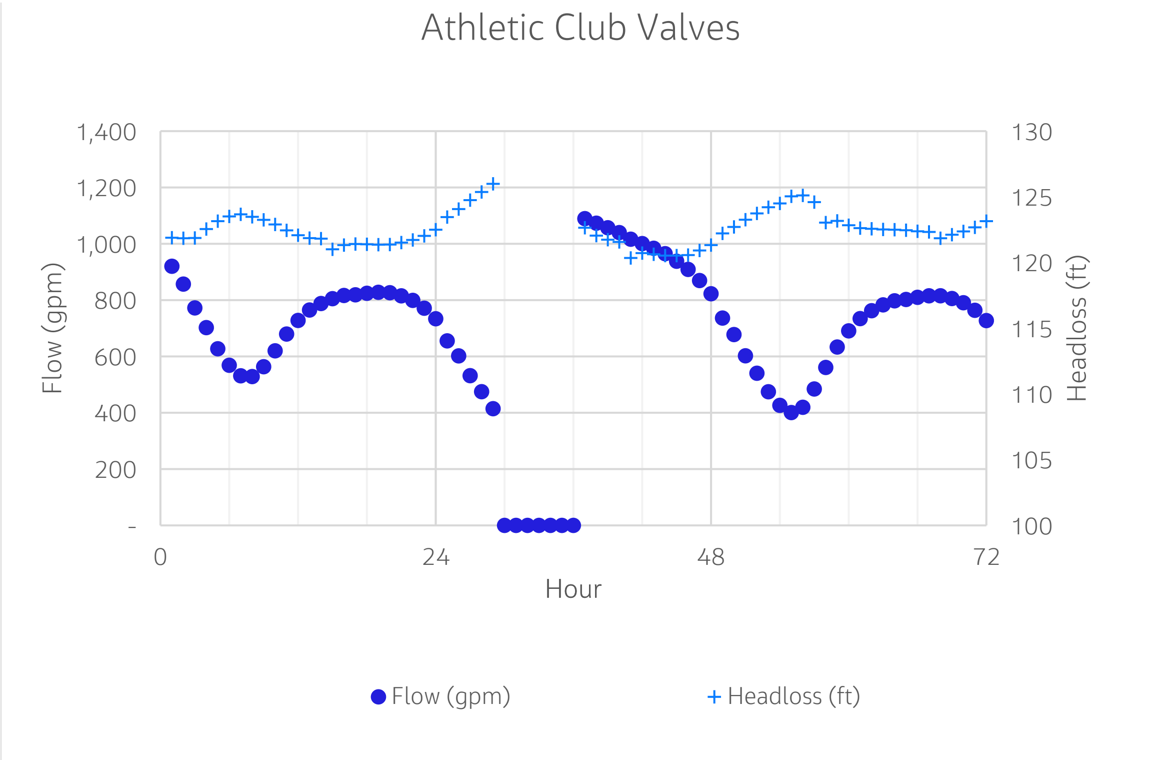

Figure 3-5. Athletic Club Site Winter Demand Over 72-hour Period

Source: Consor Engineers, LLC, 2023b

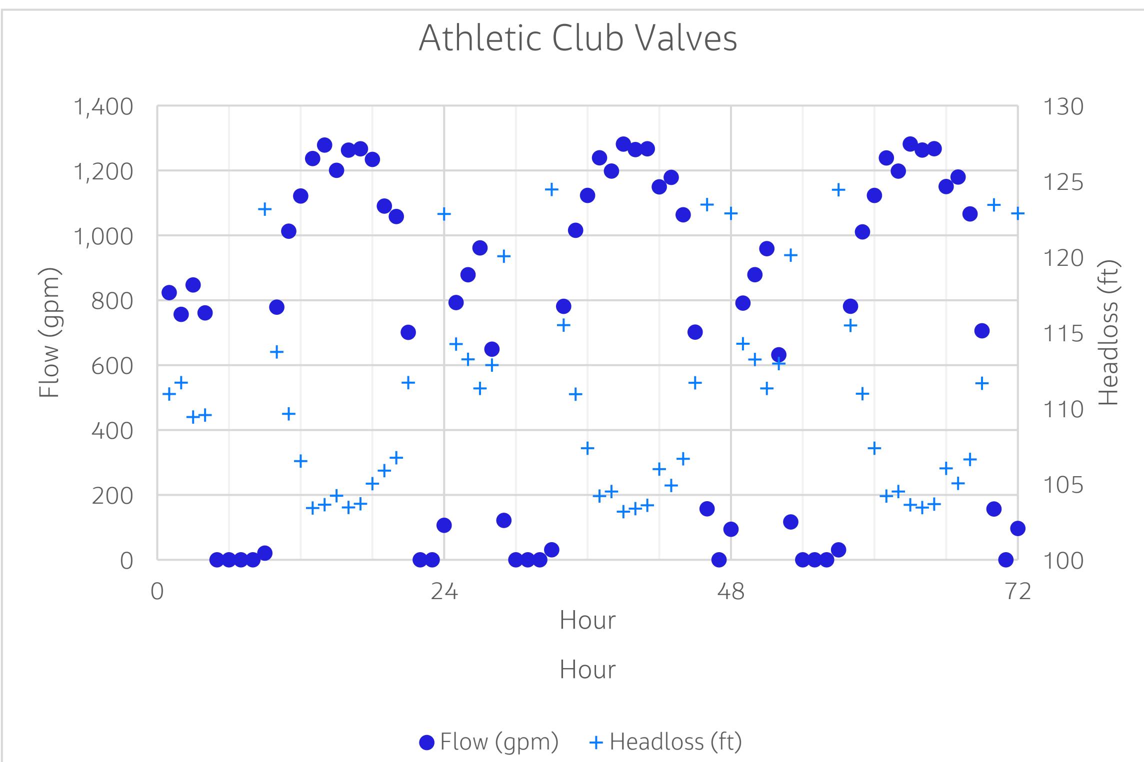

Figure 3-6. Athletic Club Site Maximum Demand Over 72-hour Period

Source: Consor Engineers, LLC 2023b (copy provided in Appendix L)

Table 3-3. Athletic Club Vendor Response Summary

Vendor name	Proposed Turbine	Power production estimate (winter/summer, kW)	Energy production estimate (kWh/year) [a]	Budgetary equipment cost [b]
Canyon Hydro (U.S. based)	Single unit installation of Cornell 3TR1, single speed	8 /12	56,603 kWh/year	$92,000
InPipe Energy (U.S. based)	Single unit installation of HydroXS-M8, variable speed	8/13	89,433 kWh/year	$141,800

[a] Energy production estimate is made while accounting for a 2-week annual off-line maintenance period.

[b] Each vendor's contract terms, and equipment offerings are different. Refer to the attached vendor quotations for further information in Appendix B for InPipe Energy budgetary quotations and Appendix C for Canyon Hydro budgetary quotations. Equipment cost does not include civil, structural, or other construction costs.

3.4 Overturf Reservoir Site

The flow into Overturf Reservoir is currently regulated by an FCV. The existing facilities are located inside the fenced reservoir compound with all water pipes and valves in a below-grade vault. A nearby support building houses control equipment. The City has no significant electrical demand at the site that could be offset by power production. The Overturf Reservoir PRV experiences zero-flow periods in both winter and maximum demand seasons, which reduces the potential for in-conduit hydropower generation compared to sites that sustain continuous flow. This is shown in Figure 3-7 and Figure 3-8. A 72-hour flow versus headloss curve was prepared to project winter and summer flow conditions.

It was assumed that the 72-hour period represents typical conditions for 6 months for each season, summer and winter. This is a reasonable simplifying assumption to facilitate the feasibility study.

Figure 3-7 and Figure 3-8 show that seasonal water demand at the Overturf PRV site varies considerably throughout the 72-hour extended period simulation for winter conditions, but is steady during the maximum demand season. The significant periods of zero flow during the winter season make this site less attractive for power generation.

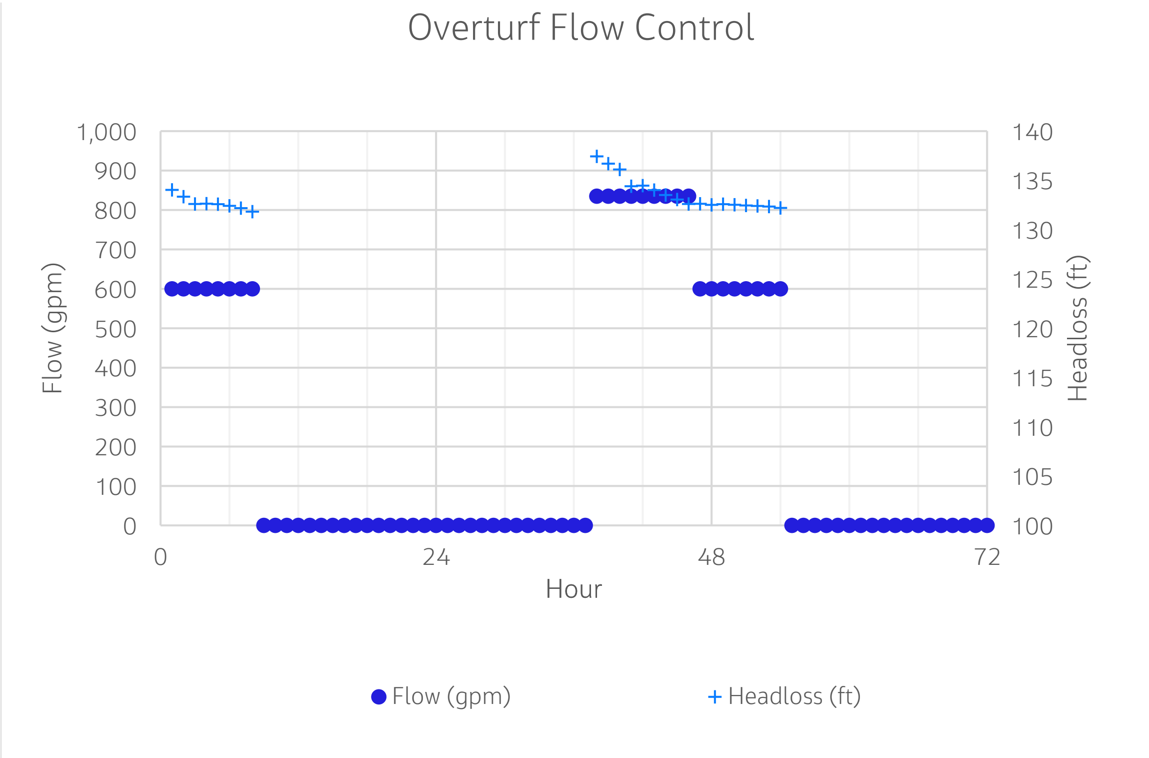

Figure 3-7. Overturf Reservoir Site Winter Demand Over 72-hour Period
Source: Consor Engineers, LLC 2023b

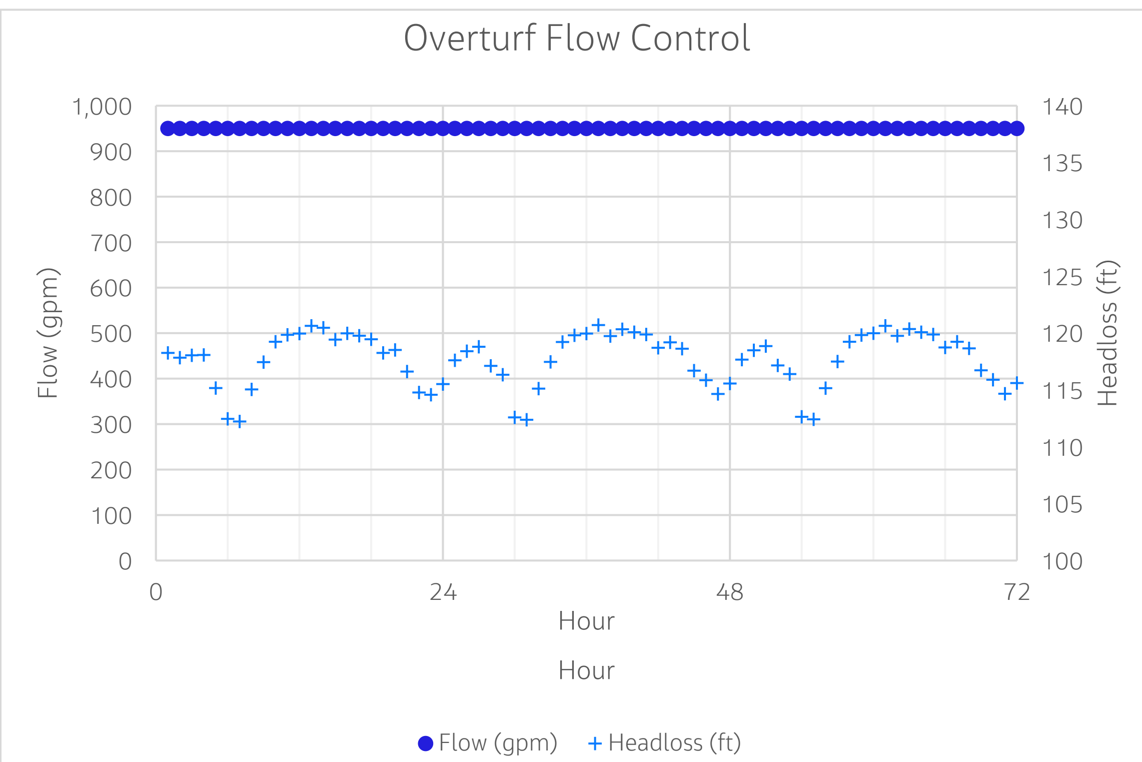

Figure 3-8. Overturf Reservoir Site Maximum Demand Over 72-hour Period
Source: Consor Engineers, LLC 2023b

Similar to the Awbrey Reservoir site, two vendors provided budgetary quotations. A summary of the vendor responses is shown in Table 3-4. The estimated power production of the two offerings is similar but the cost proposals are not comparable due to different equipment scopes included. Canyon Hydro's proposed budgetary cost estimate, power production estimate, and equipment layout were used as the basis for the assessment due to vendor responsiveness, consultant experience, and long established factory location in the Pacific Northwest, InPipe is based on Portland.

Table 3-4. Athletic Club Vendor Response Summary

Vendor name	Proposed turbine	Power production estimate (winter/summer, kW)	Energy production estimate (kWh/year) [a]	Budgetary equipment cost [b]
Canyon Hydro (U.S. based)	Single unit installation of Cornell 3TR1, single speed	9 /12	44,666 kWh/year	$93,185
InPipe Energy (U.S. based)	Single unit installation of HydroXS-M8, variable speed	10/13	100,973 kWh/year	$141,800

[a] Energy production estimate is made while accounting for a 2-week annual off-line maintenance period.

[b] Each vendor's contract terms and equipment offerings are different. Refer to the attached vendor quotations for further information in Appendix B for InPipe Energy budgetary quotations and Appendix C for Canyon Hydro budgetary quotations. Equipment cost does not include civil, structural, or other construction costs.

3.5 Conclusion

A summary of advantages and disadvantages of incorporating in-conduit hydropower generation at each site of opportunity is shown in Table 3-5. .

Table 3-5. Summary of Advantages and Disadvantages at Sites of Opportunity

Site	Advantages	Disadvantages
Outback Site	Consistent flow, consistent net head, substantial potential energy recovery, including offsetting retail power cost with energy generation and power sales of excess.	Highest capital cost of the four sites of opportunity.
Awbrey Reservoir	Consistent flow, consistent net head, Net Energy Metering (NEM), with benefit of offsetting retail power cost with energy generation.	Second highest capital cost of the four sites of opportunity.
Athletic Club	Low capital cost due to low flow and smaller turbine selection, public-private partnerships (PPPs) that could offer offsetting demand could be an option.	Frequent periods of zero flow contribute to low production. Limited power consumed on site resulting in lower economic benefit than sites with higher demand
Overturf Reservoir	Low capital cost due to low flow and smaller turbine selection, PPP that could offer offsetting demand could be an option.	Frequent periods of zero flow contribute to low production. Power Purchase Agreement (PPA) is required, which may have lower average power purchase rate than retail rates.

NEM = net energy metered; **PPA = Power Purchase Agreement.**

To screen out sites that may have an especially long economic payback period, a simple benefit-cost analysis was performed to determine if a site could be removed from further consideration. A summary of estimated energy output, annual benefit, and hydropower-only equipment cost at sites of opportunity is shown in Figure 3-6. For all sites, substantial additional electrical equipment is required to make a complete installation. A more detailed economic evaluation is described in Appendix G. For the purposes of screening, Tables 3

-6 and 3-7 identify that the Outback and Awbrey Reservoir sites are viable and should be considered further.

Table 3-6. Summary of Power Output Estimate and Equipment Cost at Sites of Opportunities

Site	Estimated annual energy Output[a]	Equipment	Freight	Commissioning	Total Equipment Costs[b]
Outback Site[c]	8,140,000 kWh	$1,113,575	$7,000	$20,000	$1,140,575
Awbrey Reservoir	621,000 kWh	$152,000	$3,500	$12,000	$167,500
Athletic Club	57,000 kWh	$93,185	$3,500	$12,000	$108,685
Overturf Reservoir	45,000 kWh	$92,000	$3,500	$12,000	$107,500

[a] Assuming 7 days down time in winter and 7 days of downtime in maximum demand season.

[b] Based on Canyon Hydro budgetary quote; does not include civil, structural, or other construction costs.

[c] Estimated energy output based on projected 2025 surface water demand.

Of the four sites of opportunity that were evaluated after system-wide screening, it became apparent that the Athletic Club PRV site and Overturf Reservoir PRV site were not viable at this time due to intermittent flow and variable head. The relative cost benefit of potential revenue compared to infrastructure cost was also evaluated during preliminary economic analysis (as described in Section 6) and the payback period exceeded 100 years. Under current conditions, these sites do not merit further consideration.

The site assessment and final categorization of the sites of opportunity are summarized in Table 3-7. Capital cost estimates for implementation of in-conduit hydropower at each site were also developed and are shown in Table 3-7. For Outback, this includes substantial piping, building, and civil improvements. For infrastructure of this type, equipment alone comprises a minority of the total capital cost.

Table 3-7. Final Categorization of the Sites of Opportunities

Site	Categories	Estimated capital cost[a]	Energy production estimate (kWh)[b]	Historical annual energy use (kWh), rounded	Recommendation
Outback Site	Viable	$ 10,823,000 - $ 17,199,000	8,000,000 kWh or more	3,500,000	Detailed economic analysis recommended in this feasibility study
Awbrey Reservoir[c]	Viable	$2,040,000	612,000 kWh	260,000	Detailed economic analysis recommended in this feasibility study
Athletic Club PRV	Not viable	$430,000 – $530,000	57,000 kWh	<3,000	Not recommended for implementation
Overturf Reservoir	Not viable	$430,000 - $530,000	45,000 kWh	<25,000	Not recommended for implementation

[a] Includes hydropower equipment, building, electrical interconnection, contingency, bonds insurance, 30% administration, and start up commissioning. Refer to Table 6-1. and Appendix H.

[b] Assumes 2 week/year annual off-line maintenance period.

[c] Estimated capital cost includes suggested electrical improvements at Awbrey Reservoir site.

Based on the preliminary assessment, the Outback site and Awbrey Reservoir site were determined to have the most potential for positive economic feasibility, and Athletic Club and Overturf sites were removed from further consideration. The following section further discusses the institutional and regulatory features that are relevant to the City, such as in-conduit hydropower incentives. Technical and economic feasibility assessments of the two selected sites are explored further as well.

4. Institutional and Regulatory Features

In-conduit hydroelectric power generation is regulated by state and federal rules and associated implementing agencies. FERC regulates power generation at the federal level and issues licenses and license exemptions for in-conduit hydroelectric power projects. In-conduit hydropower projects in Oregon are regulated by OWRD. Independent power producers, like the City of Bend, must also work with and through their local utility—in this case Pacific Power for the subject sites—to connect their power projects to the electric grid. There are state and federal regulations that cover the interaction between the power producer and the load serving utility, and the Oregon Public Utility Commission (OPUC) oversees much of this interaction.

4.1 Federal Energy Regulatory Commission Requirements

FERC regulates non-federal in-conduit hydropower resources under the Federal Power Act. Generally, in-conduit hydropower projects on navigable waterways, on federal lands, or connected to the electric grid must obtain and operate under a federal license from FERC. However, FERC has several exemptions available for both small projects (less than 10 MW) and conduit projects. Authorization is still generally required under these exemptions, but the process is streamlined and simplified. Under rules adopted by FERC in 2013, certain conduit projects qualify for a further exemption. These facilities require only FERC notification.

Under the 2013 rules for a "Qualifying Conduit Hydropower Facility," conduit hydroelectric projects are not required to be licensed or exempted by FERC if they meet a number of conditions. To qualify under this program, the conduit must be non-federal and not used primarily for the generation of electricity. The final installed capacity of the project must also be less than 40 MW. The City of Bend's projects being evaluated in this study would qualify for this program.

The City would still need to file a "Notice of Intent to Construct a Qualifying Conduit Hydropower Facility" with FERC but no approval or license would be required. FERC provides a template and instructions for filing the notice of intent. A copy of the template and exhibit example are included in Appendix J. There are no federal filing fees or annual charges associated with these projects. The projects are also exempted from federal requirements for preparing environmental impact statements and assessments, and no federal resource agency consultation is required.

According to the FERC Compliance Handbook (FERC, 2015), within 15 days of the filing of a Notice of Intent, FERC's Division of Hydropower Administration and Compliance (DHAC) makes an initial determination on whether the proposed project meets the qualifying criteria. If DHAC determines the facility fails to meet the criteria, DHAC terminates the review and issues a letter rejecting the filing and explaining the reasons for the rejection. If the facility meets the criteria, DHAC issues a public notice for 45 days. If no entity contests whether the facility meets the qualifying criteria during the public notice period, the project is deemed to meet the criteria. If an entity contests whether the facility meets the criteria, FERC issues a written determination.

4.2 Utility Regulations

The Public Utilities Regulatory Policy Act of 1978 (PURPA) requires utilities to purchase power from qualifying electric generation projects within their service territory. PURPA is implemented at the state level through rules adopted by FERC. In Oregon, PURPA is regulated by the OPUC. QFs in Oregon can either be renewable facilities with a capacity of less than 80 MW or cogeneration facilities. The Bend in-conduit hydroelectric projects would be QFs as small renewable generation facilities, and Pacific Power, as the local electric service provider, would be the purchasing utility. In some cases, it may be economic to sell power to a power utility that is not the utility immediately serving the subject site. In these cases, the power can be "wheeled" (or conveyed) through the local utility to another utility or entity (for example, a data center owner) that is purchasing the power. The local utility typically charges a “wheeling fee,” which covers the cost of transmission.

The process for becoming a QF is managed by FERC, but the OPUC and Pacific Power would be notified as part of the process. Owners of generating facilities with a maximum net power production of greater than 1 MW, like the proposed Outback facility, may obtain QF status through either self-certification or by applying for FERC certification of their project. A FERC form for QF certification is available for downloading on the FERC website (see Appendix J) . It can then be e-filed for self-certification of the project. Projects with a net capacity of 1 MW or less, like the proposed Awbrey Reservoir facility, do not need to obtain QF status, but owners of such facilities may seek certification if they wish to do so. There is no fee associated with self-certification.

The power purchase rates paid by Pacific Power for any of the generation from the in-conduit hydroelectric projects would depend on the type of interconnection agreement between Pacific Power and the City of Bend. The power produced can either be sold to Pacific Power under a PPA, Net Energy Metered (NEM), or a Partial Requirements Generation agreement to Pacific Power’s system at an interconnection meter point.

Under a PPA, Pacific Power would buy the electricity generated by the City at a negotiated and contracted rate. By regulation, the negotiated rate must be at or below Pacific Power’s “avoided cost rate,” which is defined as the cost of the utility’s generation or purchase of replacement power if the QF generation did not exist. In Oregon, avoided cost rates are based on the costs of the lowest cost resource otherwise available to the utility and are reviewed annually by the OPUC.

Pacific Power has established contracting and pricing terms for QFs within their service territory. These rates are generally updated every 2 years. They vary based on the type and schedule of the generation. Contract terms are generally 15 years. For the Bend in-conduit hydroelectric projects, the standard fixed avoided cost pricing for new non-firm base load energy would likely apply. This rate is currently 7.03 cents per kWh on-peak, and 4.84 cents per kWh off-peak for 2023, although prices are projected to decrease over the next several years to a low of 5.30 cents per kWh on-peak and 4.6 cents per kWh off-peak by 2025 (Pacific Power 2022). The power generated at the Outback site would be considered non-firm because it would vary over time of day and day of year. Application and negotiations with Pacific Power on a site-specific PPA would provide actual pricing and contract terms. Pacific Power offers several pricing options that should be considered by the City and has a sample non-firm PPA on their website.

NEM allows electric customers to install renewable energy generation to offset their own energy purchases. Electricity taken from the grid moves the electric meter for the site in one direction. Excess generation sent back to the grid runs the meter in the other direction. If a customer generates more electricity than it uses at a net metered site, the credit carries forward for future use over a period of up to 12 months. If an excess remains at the end of the 12-month contract period, the excess is donated to the Oregon low-income energy assistance program, and the producer earns no revenue on that power. NEM is available in Oregon for industrial and commercial facilities up to a capacity of 2 MW per site. Aggregation of meters at a single or adjacent site for a single customer is also allowed under Oregon rules (refer to Oregon Administrative Rule 860-039-0065), and in that case all meters at the site are evaluated against the site’s generation to determine the net electrical use for the site. These options would apply to any of the potential in-conduit hydroelectric sites in Bend but because NEM requires an adequate electric load to use the power generated on the site, each site should be evaluated separately to consider site loads versus potential generation. Based on currently available information, it appears that a standard NEM arrangement makes sense at the Awbrey Reservoir site, and a Partial Requirements Generation agreement should be implemented for the Outback site. Pacific Power has standard net metering applications and agreements available on their website, and copies are provided in Appendix K. Note that preliminary discussions with Pacific Power regarding a Partial Requirements Generation Agreement were conducted, but no example versions of such agreement were provided by the utility at the time of study publication.

Partial Requirements Generation allows electric customers to consume onsite generated electricity and then sell an excess generated power at a non-firm price, established by a power price index. A Pacific Power customer must have total nameplate generation capacity of at least 1,000 KW (which is satisfied at the

Outback site). This is preferrable to net metering for sites that produce significant excess power on an instantaneous basis, and which—over the course of a year—generate far more power than is consumed on site. The Outback site is a prime candidate for this kind of agreement. Unlike a NEM agreement, excess power is not donated at the end of a 12-month contract period, but is sold instead.

In any case, through a PPA NEM, or through Partial Requirements Generation agreement, the City would negotiate and contract with Pacific Power on the terms of the agreements. Separate agreements with differing terms are likely for each of the sites. The City will also need separate interconnection agreements for each site. Pacific Power recommends that requests for interconnection and a NEM, PPA, or Partial Requirements Generation agreement be made at least 18 months before the anticipated in-service date of the facilities.

4.3 Water Rights

OWRD, through their Hydroelectric Program, has lead responsibility at the state level for in-conduit hydroelectric power projects in Oregon. This includes reviewing and processing applications and coordinating state agency oversight. OWRD also conducts project inspections and collects the annual hydropower generation fees on behalf of the state.

In-conduit hydroelectric projects must have water rights for the water used in power generation. However, OWRD can issue an in-conduit hydroelectric generation use water right based on an existing certificated water right through an expedited process. Under this process, the diversion remains limited to the amount of water diverted and used under the underlying certificate, and other limitations of the underlying water right. The in-conduit hydroelectric water right will include conditions for fish screens, bypass flows, and fish passage as required by the Oregon Department of Fish and Wildlife. Annual hydropower fees are assessed based on the power generated, and the City can choose to pay into a statewide fish passage mitigation fund in lieu of adding fish passage to the surface water system. OWRD will invoice and collect all annual fees associated with the projects.

The process for obtaining a hydroelectric generation water right based on an existing certificate is straightforward, requiring an application to OWRD and a one-time fee of $500. All of the underlying water rights that would be used for a generation project can be aggregated into a single in-conduit hydroelectric application and fee. There is a 30-day public comment period before the final order and certificate can be issued. For the Outback site, the City would submit an application to OWRD for an in-conduit hydroelectric generation water right, based on the use of water under all of the City's certificated surface water rights. For the Awbrey Reservoir site, the City would submit an application to OWRD for an in-conduit hydroelectric generation water right based on both the City's certificated surface water rights and an array of groundwater rights sufficient to account for water used for hydropower generation in the event that the City's surface water diversions are temporarily disrupted or reduced.

OWRD has indicated that obtaining a hydropower water rights takes 4 to 6 months from application submittal including the 30-day public comment period. Applicants should carefully determine when to apply and avoid applying too soon because, once issued, OWRD requires the hydropower water right to be used within 5 years of issuance or it may be forfeited (similar to other water rights).

The Awbrey Reservoir site will require hydropower water rights for all surface water rights because the City uses only surface water for much of the year which then flows downstream in the distribution system to Awbrey Reservoir. It is acceptable to have surface water rights included on both the Outback and Awbrey Reservoir site in-conduit hydroelectric rights. Hydropower water rights for groundwater wells should be added to all current and future wells at Outback because no water can physically get to the Awbrey Reservoir site when surface water is out of service unless the Outback Wells are operating. At time of application for hydropower water rights, current system operation and configuration will confirm if any other groundwater rights should be added.

4.4 In-conduit Hydropower Incentives

There are a number of programs, some currently available and some in development, that could assist the City with financing both the development and construction of in-conduit hydropower projects at the Outback and Awbrey Reservoir sites. There is also a production incentive program that will pay the City for additional (new) green energy produced and the renewable energy credits (RECs) generated by future production have value within Oregon's REC marketplace. Potential incentive programs are identified and evaluated in the In-conduit Hydropower Incentives Evaluation Memorandum (Appendix F).

The easiest and most straightforward assistance program appears to be continued collaboration with the ETO. The ETO has funding for both development and, potentially, construction of the systems. It is suggested that the City continue their partnership with ETO as the project team continues to identify other incentives for construction, because the programs identified that will support design and construction are competitive and have varying funding mechanisms and timelines.

Federal Emergency Management Agency (FEMA) Building Resilient Infrastructure and Communities (BRIC) Grants are competitive and can provide substantial funding for compelling projects that improve resilience. This grant program has a maximum $50,000,000 grant amount in any given year per applicant and requires a 25% non-federal cost share. The City is understood to be preparing such a grant application for submission in early 2024.

Oregon's drinking water state revolving fund (DWSRF) may be a good companion program to continued work with ETO. The DWSRF has Sustainable Infrastructure Planning Project (SIPP) grants that can provide the matching funds required by the ETO to complete project design. The SIPP has been able to offer funding to all who have applied. Unlike ETO, the DWSRF loan program does not have limits on the amount of project costs that can be financed, only on the amount of loan forgiveness offered. Loan principal forgiveness is offered for all funded projects and historically has been on the order of 10% up to a maximum of $100,000. From discussions with a DWSRF project officer (Schei, 2023, personal communications) and in review of DWSRF program requirements, it was determined that projects that contribute to health and water system compliance can have greater forgiveness (25% of project cost up to $150,000). Projects for communities with water system that meet affordability criteria receive maximum principal forgiveness (50% up to $500,000). Bend would likely not meet the required affordability criteria. Additionally, Business Oregon contributes up to $30,000 ($15,000 for labor standards compliance assistance and $15,000 for federal requirements assistance) to all projects to help fund labor standards compliance. Determination of loan forgiveness occurs after a request for final disbursement has been submitted to Business Oregon.

If ETO grant awards fall short of the budget required to complete the planning, design, and construction of the project, the DWSRF loan program can be an affordable option to bridge the funding gap while also fulfilling the match requirements of other state and federal grant programs (using DWSRF state or repayment dollars that are non-federal). In addition, the City may be able to get the funds needed to proceed with the project more quickly with the DWSRF program than waiting for federal grant funding cycles. The City could use any future grant award(s) to pay down the DWSRF loan as part of an effective grant/loan laddering strategy. As with all federal funding, DWSRF-funded projects require certain American Iron and Steel (AIS) provisions in the contract. The City is very familiar with administering projects with AIS requirements. AIS requirements do not appear to currently apply to the turbine/generator assembly. Guidance should be sought from funding agencies prior to all procurement and design.

Oregon Department of Energy's Community Renewable Energy Grant Program (CREP) is another likely funding source for in-conduit hydropower facilities. As detailed in Appendix F, the CREP program has completed initial funding cycles and is not currently accepting applications. These CREP grants are awarded on a competitive basis and priority will be given to projects that support program equity goals, demonstrate community energy resilience, and include energy efficiency and demand response. The Outback site could be very competitive for a CREP grant, especially with energy resilience benefits included. The CREP anticipates additional funding cycles in the near future.

Investment tax credits, made as direct payments to municipalities, are another way for the City to recoup some of the cost of construction if it is not successful with other programs. (Direct payment to a municipality is recent development and the Internal Revenue Service is still developing rules.)

Finally, production tax credits and the in-conduit hydroelectric production incentive program will potentially be available to the City once the system is operating, and any RECs generated by production can be banked and sold by the City on the statewide REC marketplace if not included in a PPA with Pacific Power (or other power purchasing entity) or a financing agreement with ETO.

4.5 Permitting Requirements

The Outback site is located outside of the City of Bend city limits on land in Deschutes County. County land use and permitting requirements would apply to this project. The City is in the process of seeking a land transfer of certain property from the USDA Forest Service that will affect long-term planning at the site.

The Awbrey Reservoir site is within the City and City regulations and permitting would apply.

4.5.1 Deschutes County Permitting Requirements

Construction of an in-conduit hydroelectric facility at the Outback site will fall under the land-use jurisdiction of Deschutes County. The county has a land use review process and a commercial construction permit process that appear to be applicable to future development at the Outback site. The county's Building Safety Division provides review and inspection services for construction. Applications for county permits are available online. The property zoning should be verified at the time of design, as the City is in the process of seeking a land transfer from USDA Forest Service. Conceptual layouts for an in-conduit hydropower facility at the Outback site should be validated with county development requirements.

City staff will need to work with County planning staff for the permitting process and design requirements for this type of facility at the Outback site.

4.5.2 City of Bend Permitting Requirements

Construction of an in-conduit hydroelectric facility at the Awbrey Reservoir site will fall under the land-use jurisdiction of the City of Bend, as the Awbrey Reservoir site is within the Bend city limits located on land zoned for Public Facilities. The development codes for the Public Facility Zoning District are specified in the Bend Development Code (BDC) Chapter 2.6. At the time of initiating design, the City project team should consult with Community Development planners to confirm current applicable codes. The types of infrastructure required for in-conduit hydroelectric generation are similar to many other City facilities in terms of structures, mechanical, electrical, and control equipment.

5. Technical Feasibility Assessment

The information presented in this section further investigates the technical feasibility of the viable sites identified in Section 3, Preliminary Site Assessment. Based on the results of the initial assessment process, the Outback site and the Awbrey Reservoir site were evaluated in greater detail. The technical feasibility assessment of each site is presented in the following sections.

The assessments have been performed based on limited head, flow, and site information. Any further steps in project development or assessment should use complete data, assembled for an accurate prediction of future operations. Such refined analysis may be expected to further improve the certainty of equipment selection, energy and cost estimates, and feasibility assessments.

Water operations staff were closely involved in reviewing the sites of opportunity, and hydraulic modeling results of the four screened sites. Operations staff validated that the extended period simulation hydraulic model results were representative of typical winter and maximum demand seasons, and furnished actual electrical consumption data. This input contributed to the study results and recommendations provided herein. As the City moves toward implementation, proposed project features and details need to be integrated with actual facility operations, including any future optimization efforts because of the City's continuous improvement initiatives.

This report provides recommended next steps for each site, should the City choose to proceed with additional assessments or design. Final determination of a project's feasibility must also consider the implication of a range of institutional factors, including applicable FERC process exemption, in-conduit hydroelectric water rights, utility interconnection, resilience benefits, and site-related permitting discussed in Section 4.

5.1 Outback Site

5.1.1 Site Characteristics

Under a separate future project following completion of a new Outback WFF Facilities Plan, the existing Outback WFF is expected to be updated to include a new pre-sedimentation pond and pretreatment building upstream of the existing WFF infrastructure to improve treatment facility resilience and ability to treat raw water that is affected by sediment-laden water following significant wildfire in the watershed. A new in-conduit hydropower turbine generator is identified as a potential facility in coordination with other new facilities. Two locations were proposed in the Outback Siting Study (Murraysmith, 2021b). Options A and B are shown in Figure 5-1. Option A is located upstream of the proposed pre-sedimentation pond and the proposed pretreatment building. Option B is located adjacent to the proposed pretreatment building. For the purposes of feasibility study, Option A's location is investigated further.

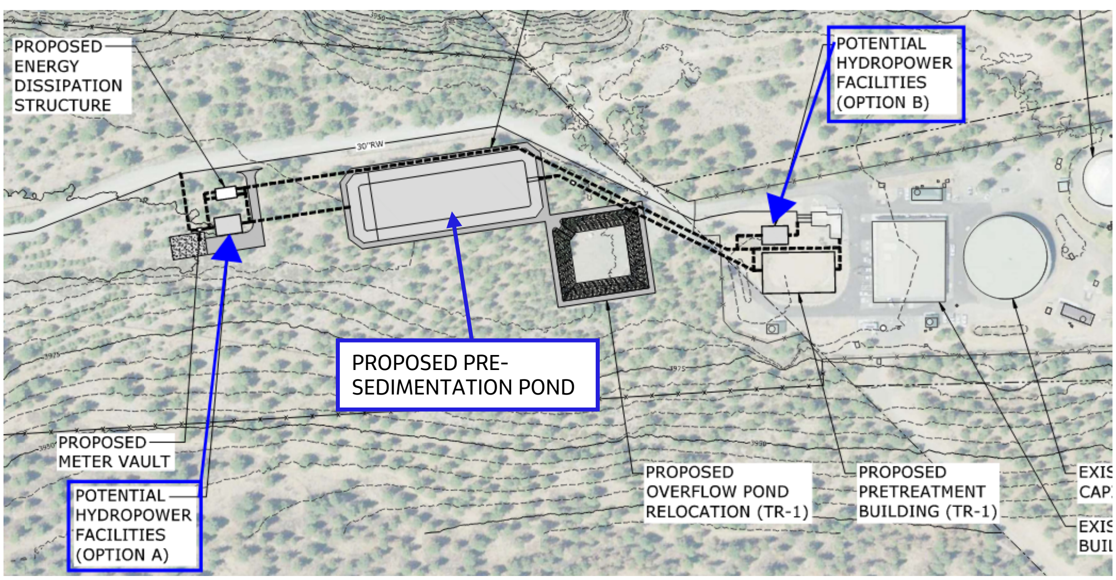

Figure 5-1. Two Proposed Potential Locations of Hydropower Facilities, Options A and B

Source: Murraysmith, 2021b

5.1.2 Water Filtration Facility Operational Constraints and Assumptions

The new in-conduit hydropower facility would be located between a new connection to the existing 30-inch-diameter raw water line and the new pre-sedimentation basin. A new facility would include the in-conduit hydropower equipment and one or more pressure dissipation valves in parallel. Once the net available hydraulic head is converted to energy or dissipated through energy dissipating valves, then water would be routed to the proposed pre-sedimentation pond or pretreatment basin as shown on Figure 5-2.

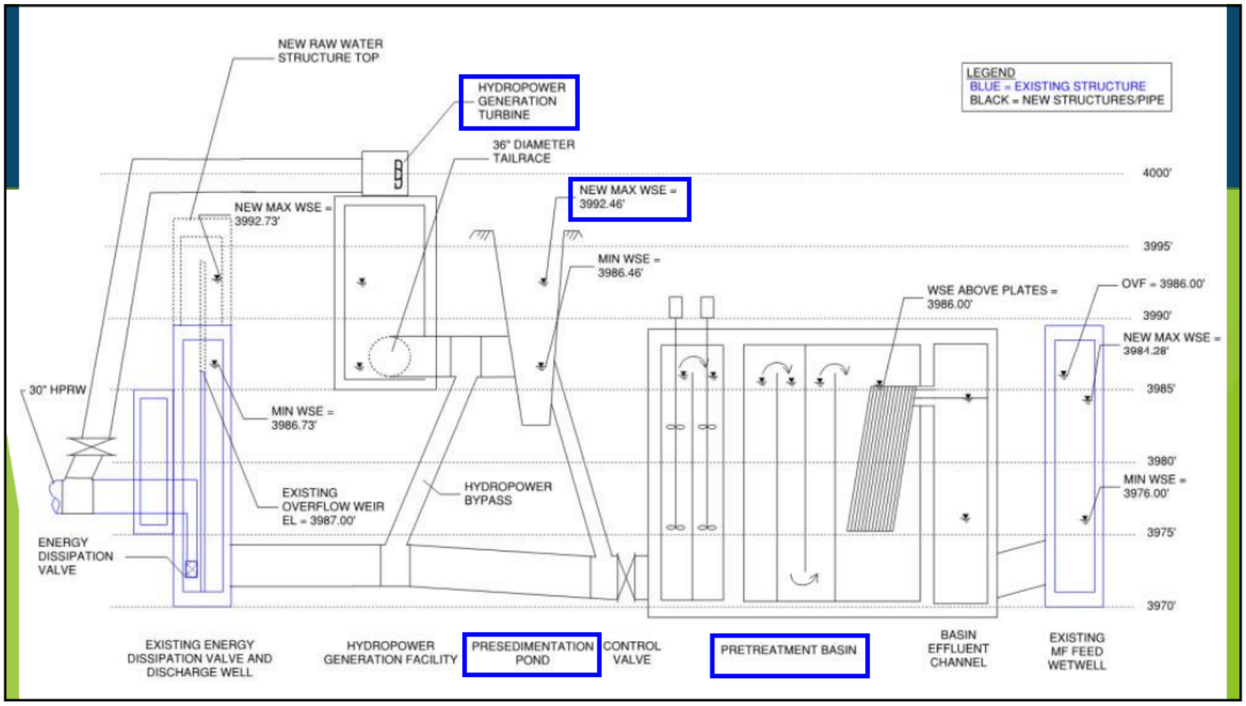

Figure 5-2. Key Elevations Along the Proposed Outback Site Development with Key Locations Highlighted

Source: Murraysmith, 2021b

Based on the iWSMP Outback Siting Study, the maximum allowable water surface elevation in the pre-sedimentation pond is EL 3,992.46 feet. The information was used to determine weir elevations, building floor slab elevation, and the turbine centerline elevation. Refer to the Outback site layout included in Appendix A.

5.1.3 Surface Water Demand

The City's diversion is currently limited to a maximum of 18.2 cfs by Special Use Permit BEN1178 issued by the USDA Forest Service, as well as by the City's Municipal Code (Section 14.10.090). The diversion rate at any point in time is further governed by regulation by the OWRD watermaster, such as regulating flows in Tumalo Creek to achieve in stream water rights, or sharing water rights with similar priority dates during low stream flow conditions. Typical historical and projected surface water diversions to the Outback site range between 5 to 18.2 cfs, depending on system demand. When the WFF is offline, and when surface water diversions are insufficient to meet system demand, the City operates groundwater wells to satisfy demand. The wells at the Outback site discharge downstream from the WFF and will not flow through the turbine at the Outback site. The equipment selection and energy production estimate assume the maximum surface water available for in-conduit hydropower generation is 18.2 cfs.

5.1.4 Equipment Selection

Jacobs solicited equipment selection and budgetary quotations from various turbine manufacturers using boundary condition information found in the iWSMP such as Figure 3-2 and Figure 5-2. The proposed equipment sizing and costs are summarized in Table 3-1. The received budgetary quotations were comparable and within the same order-of-magnitude. However, each vendor's contract terms and details of the offerings are different. Refer to the attached vendor quotations for further information in Appendix A. Specific vendor offerings are expected to be evaluated during final design and procurement for the facility. It is conservative to assume a slightly lower power production potential, and Canyon Hydro's proposed budget, power produc tion estimate, and mechanical parts were used for further feasibility study investigation due to vendor responsiveness, consultant experience, and long established factory location in the Pacific Northwest.

Canyon Hydro has proposed a horizontal dual-nozzle Pelton turbine with hydraulic actuation, 1.35-MW/4,160-volts-alternating-current (VAC)/3-phase/60-hertz (Hz) synchronous generator, hydraulic power unit (HPU), programmable logic controller based controls panel with metering and utility grade protective relays, indoor generator neutral cubicle, 18-inch 300 class ball valve with hydraulic actuation, ball valve bypass line, 18-inch restrained dismantling joint, and structural steel equipment mounting frames. The expected system production for this equipment package is 1.23 MW at a design flow of 18.2 cfs, gross head of 1,017 feet, and net head of 947 feet.

5.1.5 Estimated Energy Production

Based on information provided by Canyon Hydro (refer to Appendix A) and the projected surface water demand (GSI Water Solutions, Inc., 2023a), the proposed turbine is estimated to generate power output as shown in Figure 5-3. If installed as assumed, the turbine is projected to produce over 8,000,000-kWh of energy per year as shown on Figure 5-4 and Table 5-1.

The energy production projection accounts for 2 weeks of operational downtime for maintenance purposes each year. GSI Water Solutions, Inc. (the City's water rights consultant) evaluated multiple water right diversion scenarios (copy provided in Appendix I). The following energy production estimate is based on the "complex model," which accounts for the potential diversion reductions required by the Watermaster during low streamflow conditions (GSI Water Solutions, Inc., 2023b).

The 50 years of projected surface water diversion flows are based on projected system demand with consideration of the impact of water conservation measures on demand, limitations on raw water flows during periods of low streamflow, and how surface water flows could be influenced by climate change. This is intended to represent a conservative estimate of Bridge Creek pipeline flows (that is, projected diversions are lower than may actually be allowed and experienced and therefore these analyses may underpredict energy generation potential on an annual basis.)

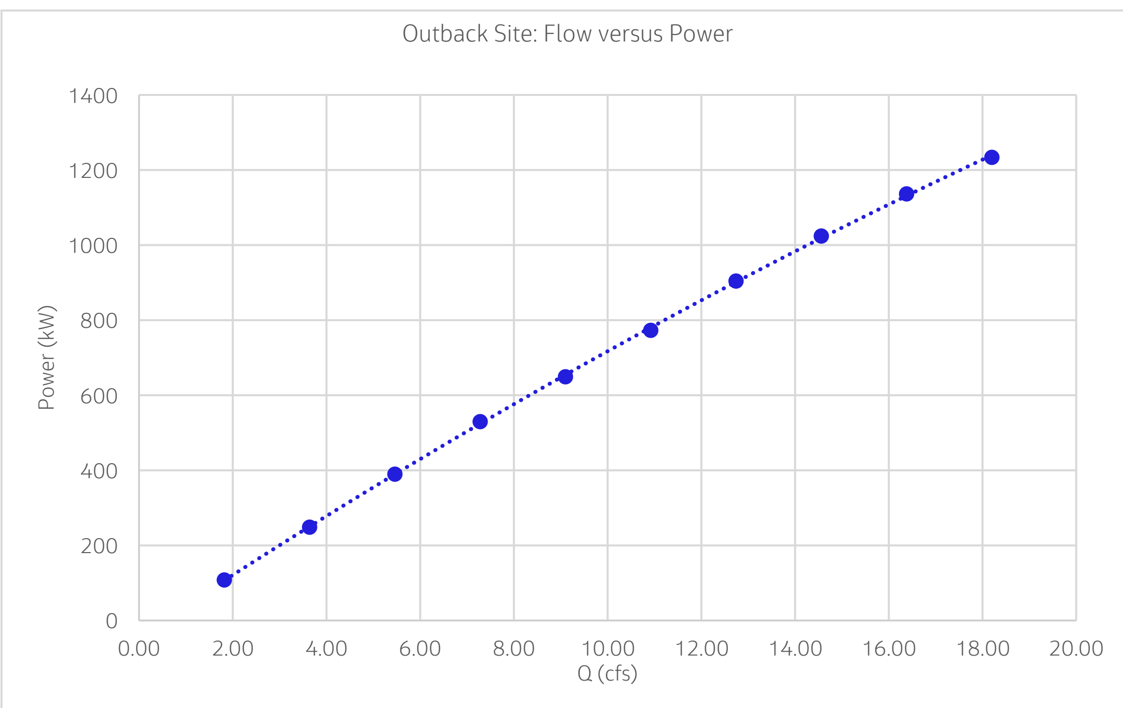

Figure 5-3. Flow Versus Power Production Using Canyon Hydro-proposed Pelton Turbine

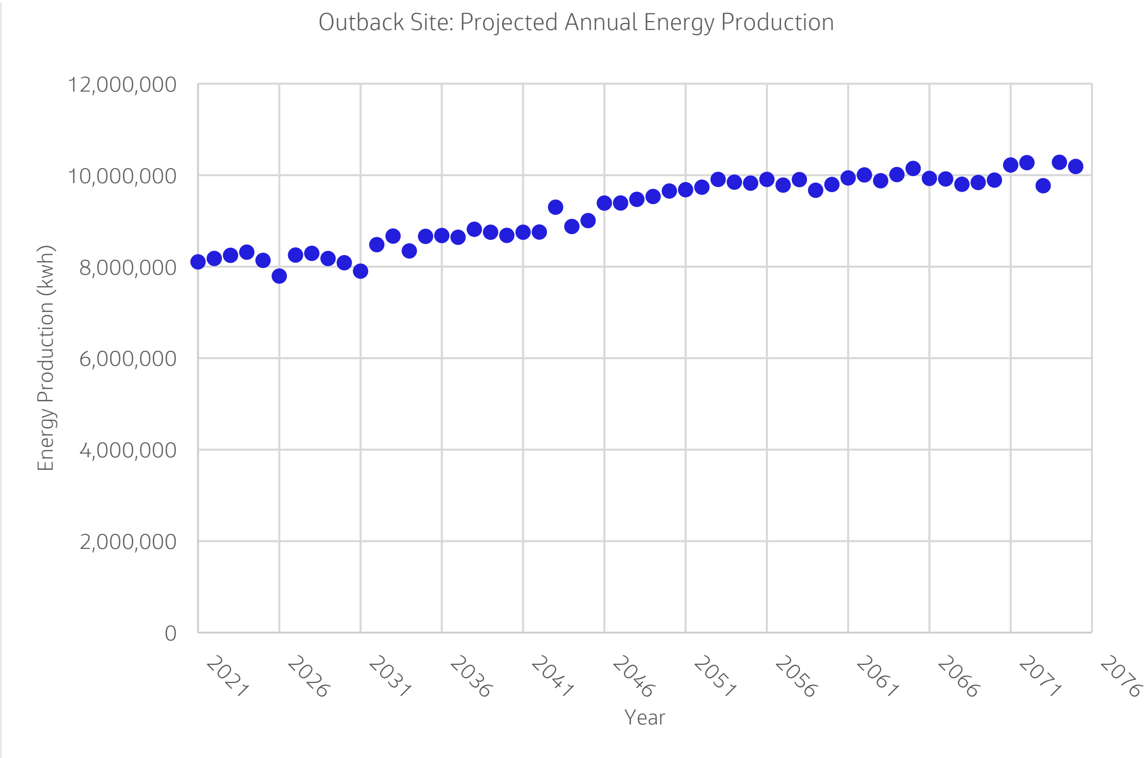

Figure 5-4. Projected Energy Production at Outback Site with 2 Weeks Assumed Annual Operational Downtime

Table 5-1. Projected Energy Production at Outback Site with 2 Weeks Assumed Annual Operational Downtime (2021 flow record as example)

Condition	Flow total (MG)	Generator output (kW)	Energy production estimate (kWh/year)	Historical annual energy use (kWh), rounded
2021 Flows	3,188	1,300	8,100,000	3,500,000

5.1.6 Proposed In-conduit Hydropower Site and Building Layout

The location of the proposed in-conduit hydropower facility is shown in Figure 5-5. Based on this information, a feasibility level site layout sketch (Figure 5-5) and building layout sketches (Figure 5-6, Figure 5-7, and Figure 5-8) were developed. The proposed in-conduit hydropower facility is accessible through double-hung person doors on both sides of the building. A coiling overhead door in conjunction with a 6-ton capacity bridge crane will allow equipment access. The overall building footprint is 51 feet, 4 inches by 44 feet, 8 inches, and the exterior of the building consists of 12-inch concrete masonry unit blocks.

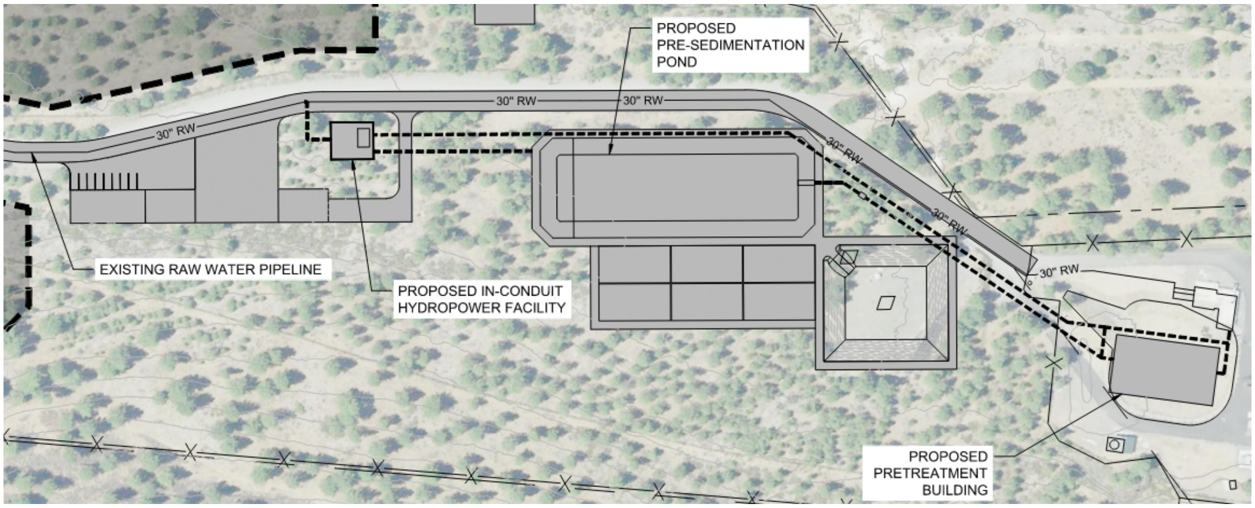

Figure 5-5. Site Layout of Proposed In-conduit Hydropower Facility

For an enlarged PDF version of the drawing, refer to Appendix A.

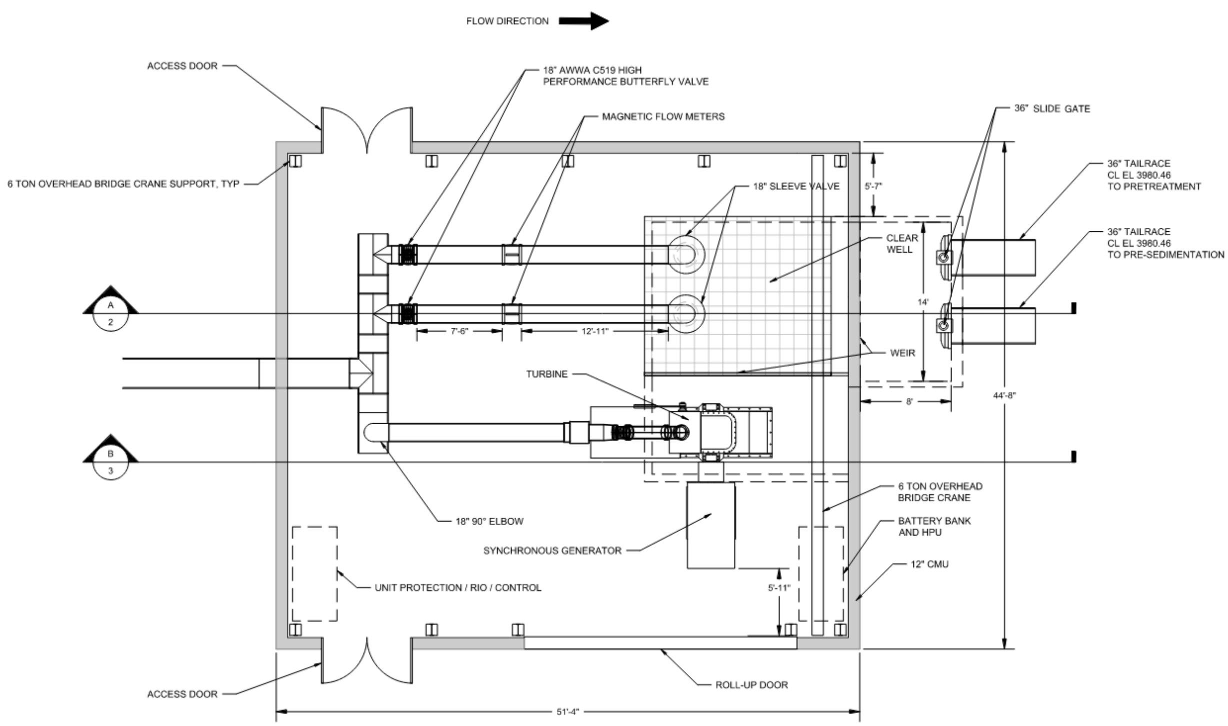

Figure 5-6. Plan View Building Layout of Proposed Outback In-conduit Hydropower Facility

For an enlarged PDF version of the drawing, refer to Appendix A.

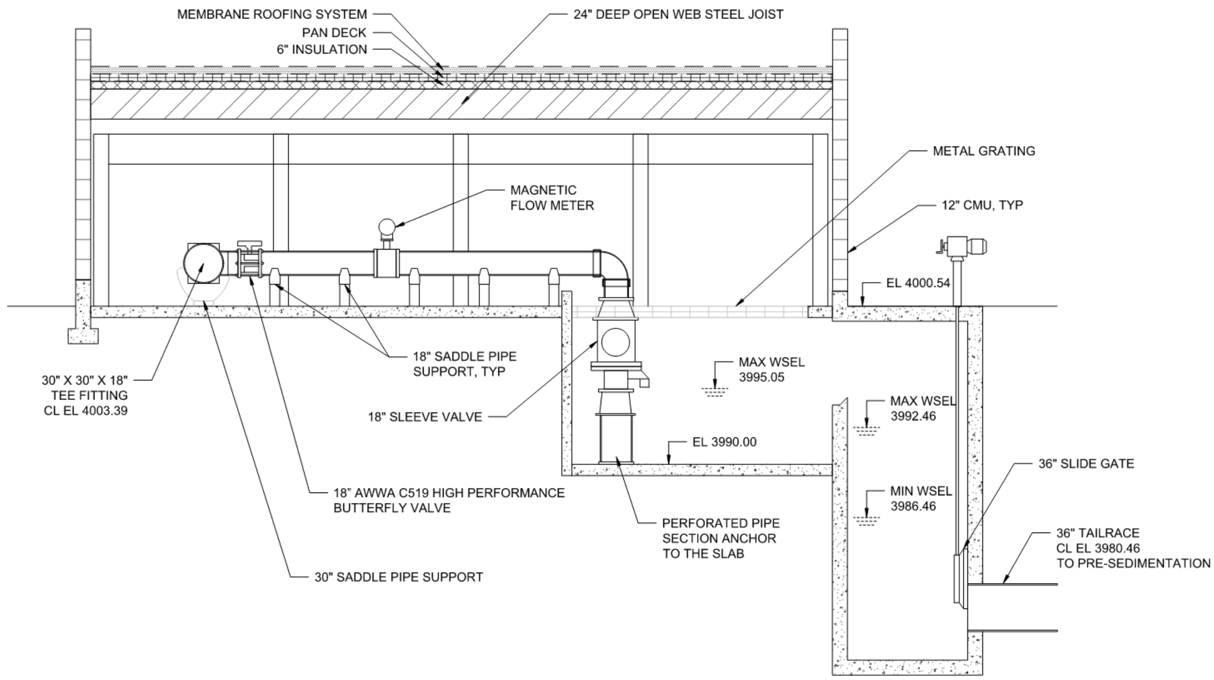

Figure 5-7. Building Section of Proposed Outback In-conduit Hydropower Facility, Sleeve Valve Assemblies

For an enlarged PDF version of the drawing, refer to Appendix A.

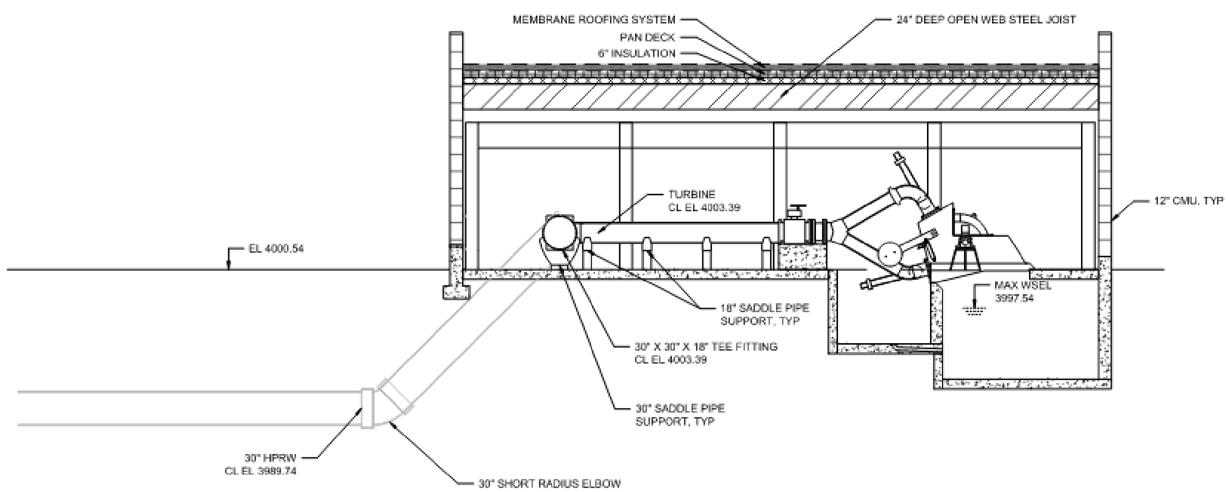

Figure 5-8. Building Section of Proposed Outback In-conduit Hydropower Facility, Pelton Turbine Assembly

For an enlarged PDF version of the drawing, refer to Appendix A.

The proposed facility is to receive water from the 30-inch-diameter raw water line and return the water to pre-sedimentation pond or the pretreatment facility downstream. The centerline of the existing raw water line at the approximate start location of the proposed in-conduit hydropower supply conduit is EL 3,989.74 feet. A below-ground connection must be made to the in-conduit hydropower facility as shown on Figure 5-8. The yard pipe materials required to create the proposed connection and bypass are included in the opinion of probable construction cost, assuming Schedule 20 steel pipe.

Inside of the proposed facility, the turbine will sit at a centerline EL 4,003.39 feet. The assumed ground elevation is EL 4,000.54 feet based on the provided site contour information. Two 18-inch sleeve valves are configured in parallel with the turbine. Although only one sleeve valve would be required for functional operation, two sleeve valves will be provided to give the facility an enhanced level of redundancy and to allow operations to maintain either sleeve valve while maintaining the surface water diversion and continuing turbine operation. The proposed sleeve valves will be attached to a perforated pipe anchored to the downstream clear well slab to discourage concrete erosion and further dissipate the energy in the water, as shown in Figure 5-7.

The turbine and the sleeve valves will share a discharge clear well separated from the downstream flow by a weir, which allows isolation of the turbine bay. When the turbine is offline due to maintenance and other anticipated operational reasons, the WFF will remain operational by using the sleeve valves to feed the WFF. The clear well is designed to overflow into a drop structure via a weir. The drop box outlet will connect to two 36-inch-diameter yard pipes, one to pretreatment and one to pre-sedimentation.

5.1.7 Electrical Interconnection

The Outback site in 2021 had an aggregated power demand of 3,355.000 kWh for all meters. Based on the 2021 surface water diversion flows, the City could expect power production from a new turbine/generator on the order of 8,400,000 kWh, for an excess generation of about 5,000,00 kWh if all power demand onsite is satisfied with generation. This substantial excess production will drive decisions about the most economically beneficial way to interconnect.

The existing Outback WFF consists of the following facilities, with each facility having its own utility service, meter, and transformer:

- Outback Wells 6 and 7 Control Building
- Outback Wells 1 and 2 Control Building
- Outback Wells 3, 4, and 5 Control Building
- Chlorine Building
- Filtration Facility

The existing WFF electrical distribution system consists of a 1,000-kW standby generator, 3,000-ampere (A) main switchboard (SWBD), and a 3,000-A service entrance SWBD. The main SWBD includes an automatic transfer controller (ATC) that allows the WFF to switch from utility power to generator power in the event of a utility power failure. In addition, the Filtration Building has an existing photovoltaic (PV) system installed on the roof and connected to the main switchboard. A separate PV system is connected to Well 6 and 7. The PV system is available only when the electrical system is on utility power. After a site visit and analysis of the credit and incentives from Pacific Power, three scenarios were developed and evaluated for the connection of the proposed 1.3-MW, 4,160-V three-phase in-conduit hydropower unit at the Outback site.

Three scenarios are developed to explore various electrical configuration options at the Outback site: Scenario 1A/1B, Scenario 2A/2B, and Scenario 3. Scenarios 1A and 1B have the same electrical configuration. They are treated as one scenario when concerning electrical interconnection options. The same is true for Scenarios 2A and 2B. The three scenarios are described in detail in following paragraphs. The distinction between Scenarios 1A and 1B lies in how the power generation benefit is applied based on the agreement between the City and Pacific Power. This is discussed further in Section 6, Economic Evaluation.

Scenario 1A/1B connects the in-conduit hydropower unit directly to the utility via a step-up transformer, which would step the 4,160 V generated by the in-conduit hydropower up to 12,470 V, which would then be connected to the utility and metered there. (Refer to Electrical Site Plan Scenario 1A/1B and Electrical One-

Line Diagram Scenario 1A/1B in Appendix A). This system requires no additional modifications to the existing electrical system outside of any building-specific loads for the in-conduit hydropower facility (heating, ventilation, and air conditioning, supervisory control and data acquisition [SCADA] system, and similar). The ability to aggregate net metering at the site (as discussed in the Utility Regulations Section above), makes this scenario the least invasive to the existing plant electrical infrastructure, while allowing the City to realize the benefit of the in-conduit hydropower and NEM for the entire Outback facility. It is not clear that Partial Requirements Generation would be allowed by Pacific Power in this electrical configuration.

Scenario 2A/2B consists of connecting the new in-conduit hydropower unit to the main switchboard in the Filtration Building via a 4,160-V to 480-V step-down transformer and a 2,000-A circuit breaker (Refer to Electrical Site Plan Scenario 2A/2B and Electrical One-Line Diagram Scenario 2A/2B in Appendix A).

The main circuit breaker for the in-conduit hydropower unit will be connected to, and controlled by, the ATC. The existing ATC will need to be reprogrammed or replaced to include the control and status monitoring of the in-conduit hydropower main circuit breaker. A new medium-voltage duct bank system with medium-voltage utility access holes will be installed from the in-conduit hydropower facility to the new 4,160-V to 480-V transformer outside of the existing Filtration Building. (Refer to the Drawing Outback-Electrical Site Plan Scenario 2A/2B in Appendix A for proposed site changes.) No changes are proposed to the connection of the existing PV system.

Partial Requirements Generation may be permissible by Pacific Power in this electrical configuration, but it is unclear if any excess power produced would be credited against other onsite meters. The status monitoring of the in-conduit hydropower main circuit breaker, the two main breakers, and tie circuit breaker at the switchboard, will allow the electrical system to have the following additional flexibility:

- Ability to run on utility and in-conduit hydropower simultaneously (normal operation).
- During a utility power outage, the electrical system will have the option to run on generator and in-conduit hydropower, or in-conduit hydropower only (depending on instantaneous hydro unit output).

The advantages of Scenario 2A/2B include the following:

- Flexibility in the filtration facility electrical system to use utility, in-conduit hydropower, or generator power.

The disadvantages of Scenario 2A/2B include the following:

- The 2022 utility data show that the power generation that will be produced annually by the 1.3-MW hydropower unit will be significantly in excess of filtration facility power demands. This is a disadvantage under the NEM scheme because Pacific Power will not pay for power produced by the in-conduit hydropower unit that was not consumed each month, resulting in unrealized power sale benefits. NEM results in power produced by the in-conduit hydropower unit being carried over as credit to the customer account for 12 months. Credits roll over month-to-month for a 12-month period, then an annual true up occurs (typically in March) where excess power gets donated and the net meter resets to zero. Refer to the Utility Regulations section above for additional information. Scenario 4 (Partial Requirements) solves this disadvantage by allowing revenue generation from the excess produced power.
- Capital cost higher than Scenario 1.

Scenario 3 physically consolidates the utility connections across the entire site and consists of installing a new 1,200-A medium-voltage switchgear (MVSWGR), which will be connected to and metered via a new 12.47-kilovolt (kV) utility service and operate at 4,160 V via a new transformer. The 1.3-MW in-conduit hydropower unit will connect to the MVSWGR via a draw-out circuit breaker. Partial Requirements Generation is clearly applicable to this configuration. The MVSWGR will feed a new 4,160-V to 480-V distribution transformer to feed a new low-voltage switchgear (LVSWGR), which will have individual feeder breakers to the following sites:

- Outback Wells 6 and 7 Control Building
- Outback Wells 1 and 2 Control Building
- Outback Wells 3, 4, and 5 Control Building
- Chlorine Building
- Filtration Building
- Future wells
- Future Pretreatment Facility
- Other future facilities

The number, type, and demand of future facilities at Outback are not fully understood and will be the subject of upcoming WFF facilities Plan development. The potential resilience and economic benefits of the Scenario 3 electrical configuration will be realized by powering future facilities from onsite generated in-conduit hydropower. This resilience benefit is highly valuable and positions the City to uniquely maintain a high level of water service during conditions that could take the grid out of service, such as a potential regional disaster like the Cascadia Subduction Zone earthquake.

For Scenario 3, the existing filtration facility utility feed circuit breaker will be connected to the new LVSWGR. Refer to Drawing Outback-04E-2 Scenario 3 (Appendix A) for details. Due to the utility feed and the in-conduit hydropower unit being connected at the MVSWGR, the electrical system for the entire site has the ability to run on in-conduit hydropower in the event of a utility failure. Site changes will be required to accommodate the new electrical equipment. Refer to Electrical Site Plan Scenario 3 in Appendix A for details.

A new medium-voltage duct bank and medium-voltage utility access hole system will be installed from the in-conduit hydropower facility to the MVSWGR. The new utility meter, MVSWGR, 12.47-kV–4,160-V transformer, 4,160-V to 480-V transformer, and LVSWGR will be located north of the existing Wells 6 and 7 Control Building. A low-voltage duct bank and low-voltage utility access hole system will be installed from the LVSWGR to the five sites listed in this section. There will be no changes to the connection of the existing PV systems.

The advantages of Scenario 3 include the following:

- Reduces the amount of utility feeds at the Outback site to only one.
- Simple connection of future new electrical demands from new facilities such as additional wells, new pre-treatment processes. Potential savings from avoiding multiple (or replacement) electrical feeds, having invested in new medium voltage switchgear.
- Provides the ability to use the in-conduit hydropower produced across the entire plant, maximizing the in-plant usage. This is a substantial water system resilience benefit.
- Flexibility in the entire Outback facility electrical system to use utility, in-conduit hydropower, PV, or generator power (generator power is currently provided for the filtration facility only), with Partial Requirements Generation, or NEM interconnection.
- Scenario 3 resilience benefits are likely to qualify the project for federal and state incentive funding related to resilience, and such incentives are less likely with other scenarios.

The disadvantages of Scenario 3 include the following:

- Least cost effective, mainly due to the capital cost of the required electrical infrastructure required to realize resilience the benefits.

- More modifications required to the existing Outback site—intrusive to the operation of the plant in the short-term during construction, but is easily manageable with advanced planning and seasonal construction constraints.
- More electrical equipment, duct banks, and electrical handholes will be installed and require future maintenance.

5.1.8 Operations and Maintenance Requirements

Anticipated O&M of an in-conduit hydropower system consists of periodic maintenance activities and training for the facility operation. Operators of nearby in-conduit hydropower facilities reported minimal standby equipment and spare part costs. Site visit summaries from two site visits performed by City and consultant O&M staff are included as a report attached in Appendix D. Representative periodic O&M requirements are listed as follows by daily, yearly, and one-time categories. The estimated costs associated with the listed O&M activities are reflected in the economic evaluation (refer to Appendix G).

1) Daily walkthrough, 1-hour maximum, staff labor includes the following:
    a) Temperature readings of bearing, generator, oil temperatures in HPU
    b) Water flow
    c) Oil levels
    d) Power output
    e) Collect any additional data deemed necessary.
2) Once a year, minimum 1 week, maximum 2 weeks, manager and staff labor includes the following:
    a) Mechanical checks, including HPU oil sample testing, oil changes.
    b) Electrical testing
    c) Transformer winding insulation testing.
    d) Primary transmission cable condition assessment
3) Operator education and training include the following:
    a) A short educational course for operators and managers (tuition and labor for two to three operators)
    b) Example courses and programs advertised and recognized by ETO include the following:
        i) Building Operators Certification Program (created by the Northwest Energy Efficiency Council)
            (1) Building Operator Certification Level I – Building System Maintenance (74-hour online program)
            (2) Building Operator Certification Level II – Equipment Troubleshooting and Maintenance (61-hour online program)
        ii) Energy Management Technician Program (2-year online course offered by Lane Community College)
        iii) Building Energy and Controls Apprenticeship Program (online and paid apprenticeship)
    c) Link to further information: https://www.energytrust.org/commercial/tools-resources/
    d) Alternatively, the City may plan to contract out certain maintenance responsibilities to a qualified contractor or consultant. One commonly out-sourced maintenance responsibility is any analysis that

requires connecting to protective relays (such as the relays that Pacific Power typically requires on all in-conduit hydropower systems connected to its system).

4) Necessary third-party consulting for tasks outside of in-house capabilities.

5) Startup, commissioning, and training by the turbine manufacturer, for a one-time fee, and typically included in the capital cost of equipment and time of construction.

The anticipated O&M costs are summarized in Table 5-2.

Table 5-2. Anticipated O&M Cost Items at Outback Site (annual unless otherwise noted)

O&M daily operation, staff, $70/hour, 1 hour/day/year	$24,570
O&M yearly maintenance, manager, $90/hour, 80 hours/year	$7,200
O&M consulting, third party ($/year)	$2,000
O&M in-house, one-time, offsite education, three people	$7,500

5.1.9 Additional Considerations

Although not discussed extensively in this feasibility report, the following items should be considered in planning and design of new facilities::

- Visual and audible impacts of the project:
  - Machine noise at in-conduit hydropower facilities is a concern, particularly if the facility is to operate throughout the day and night. However, with proper maintenance and building insulation and acoustic design measures, it is possible to minimize the noise impact on the surrounding areas. Design of the building envelope can meet virtually any noise ordinance and the proposed masonry and concrete deck roof are understood from experience to offer excellent sound attenuation capabilities. Special attention is required for doors, louvers, and windows to achieve acoustic design criteria.
- Environmental impact and benefits:
  - Implementation of in-conduit hydropower facilities at the Outback and Awbrey Reservoir sites would not increase diversions from Bridge Creek. No additional environmental impact due to in-conduit hydropower construction or operation is anticipated. Because the proposed in-conduit hydropower facility is located on a pipeline to a water treatment facility, land disturbance is already accounted for in the construction of the other infrastructure.
  - Anticipated environmental benefits include reduced greenhouse gases due to offsetting the City's energy consumption with carbon-free in-conduit hydropower. This reduces the fossil fuel consumption and promotes renewable energy production.
  - Implementation could make meaningful progress in alignment with the City's Community Climate Action Plan, including reduction of community-wide fossil fuel use by 40% by 2030, and 70% by 2050. 2,343 metric tons of CO_2 could be offset annually by the renewable energy generated at the Outback site. The carbon offset mass was estimated using the U.S. Environmental Protection Agency (EPA) estimated carbon emission rates in the Northwest Power Pool (EPA, 2023). Pacific Power literature indicates that coal fired power sources make up 56% of the utility's basic service resource (Pacific Power, 2020).
- Associated risks:
  - Emergency shutdown of the in-conduit hydropower turbine. A surge in the pipeline can be caused by the turbine runaway or fast closing inlet valve. Such risk can be mitigated with electrical protective relays and a robust control system that shifts water from the turbine to the

PRVs. Hydraulic transient analysis is recommended to be performed during design to determine whether additional surge mitigation measures are required.

- Resilience against natural disasters or power outages:
  - For the WFF in Scenarios 2A and 2B, and entire site for Scenario 3, the isochronous island mode capability of the proposed in-conduit hydropower facility further reinforces the City's resilience against natural disasters and occasional utility power outages. The island mode allows continued supply of potable water to much of the City's service area and can provide a reliable source of municipal drinking water even during extended periods of power disruption such as that anticipated to be caused by the Cascadia Subduction Zone earthquake.
- Benefit from experiences at other operating facilities:
  - Incorporate knowledge and best practices from other in-conduit hydropower operators, including those visited during this feasibility study. Similar in-conduit hydropower generation projects are summarized in the Post Site Visit Reports provided in Appendix D.

5.1.10 Outback Site Summary

Implementation of in-conduit hydropower at the Outback site will yield a substantial net export of power in the near term and long term. The City should proceed to implement a Pelton style turbine and generator, and integrate such design with the proposed pre-treatment processes that will be identified and detailed through the upcoming WFF Facilities Plan. Further development of the in-conduit hydropower facility at Outback site must entail close coordination with planned capital improvements at the City's WFF.

Implementation of electrical Interconnection via Scenario 3, wherein all Outback site electrical meters are physically integrated will provide the most resilience benefit (due to ability to power entire site in isochronous mode).

A Partial Requirement Generation interconnection agreement appears to be the most economically beneficial as detailed in the economic evaluation provided in Appendix G.

5.2 Awbrey Reservoir Site

5.2.1 Site Characteristics

The Awbrey Reservoir site is located within the City-owned Awbrey Reservoir property on the south side of Awbrey Butte adjacent to Hillside Park. The ongoing Awbrey Butte Waterline Improvement project is replacing an existing transmission main and FCV with a new 30-inch-diameter transmission main entering the Awbrey Reservoir property and a new FCV to feed Awbrey Reservoir. The design effort is led by others and the waterline project team was provided with a draft concept of the proposed FCV valve facility design during this feasibility study.

The City intends to construct the FCV valve (referred as "altitude valve" on Figure 5-9) building before the potential construction and commissioning of the in-conduit hydropower facility. If the City chooses to proceed with construction of in-conduit hydropower at this site, the in-conduit hydropower facility will be constructed as an expansion to the proposed new valve building. The exact location, elevation, and dimension of the in-conduit hydropower facility depends heavily on the final design of the valve building.

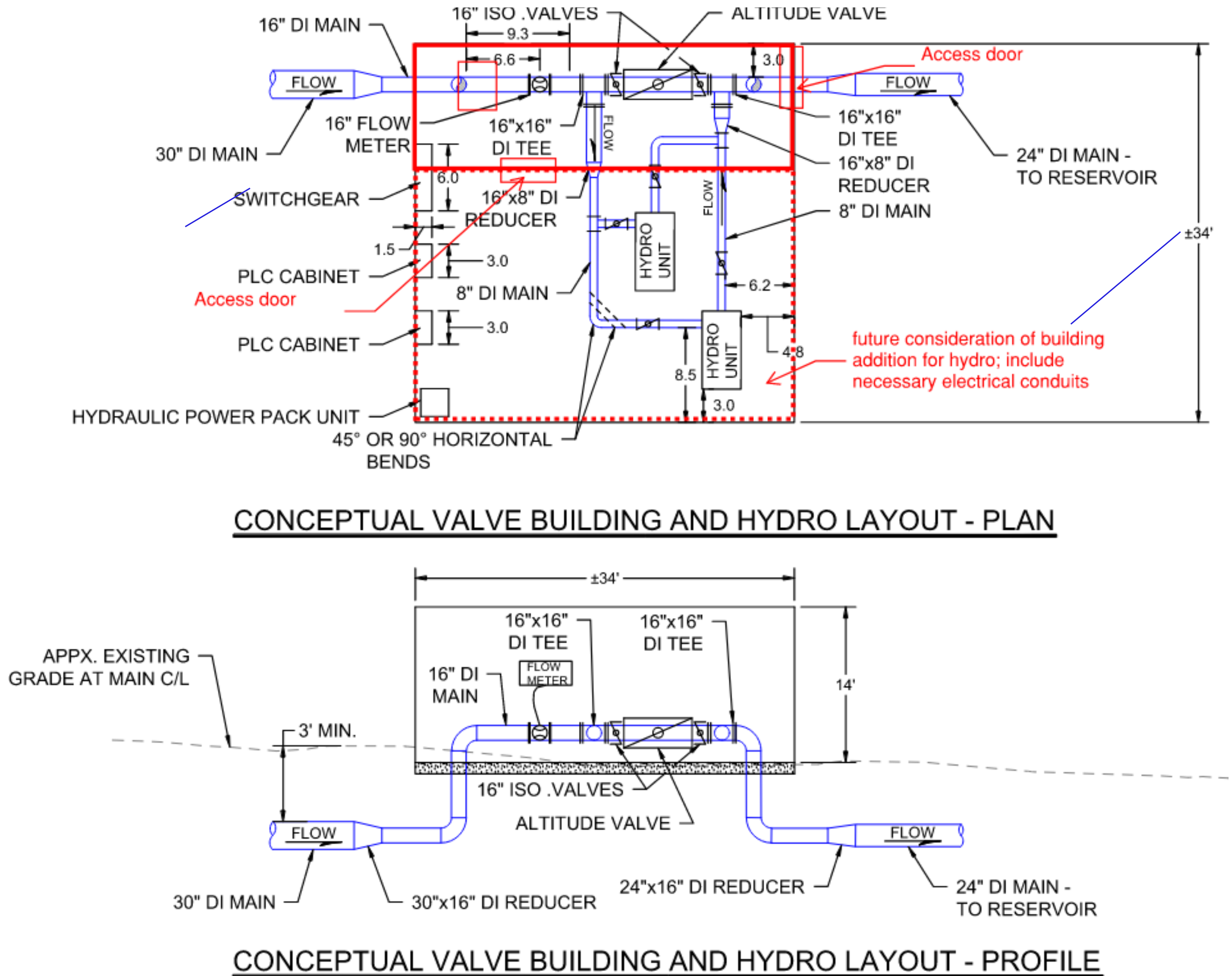

Figure 5-9. Proposed FCV Facility Draft Layout as Provided by DOWL

Source: DOWL 2023

For an enlarged PDF version of the drawing, refer to Appendix B.

The technical feasibility of the Awbrey Reservoir site must account for the currently developing valve building design prepared by others. For this reason, most of the design decisions are intentionally deferred. Close coordination during final design of the transmission main and new FCV is required with the City design criteria identified in this feasibility study to account for the potential expansion of the valve building. A successful design development must accommodate the operation of the new FCV as well as the potential in-conduit hydropower facility without interference.

5.2.2 Equipment Selection

Jacobs solicited equipment selection and budgetary quotations from various turbine manufacturers using boundary condition information presented in Figure 3-3 and Figure 3-4. The findings are summarized in Table 3-2. Canyon Hydro has proposed dual installation of Cornell 5 TR4 outfitted with a 74-kW, 1,200 revolutions per minute (rpm), 480-VAC, 60-Hz, three-phase induction generator. Cornell is a "pump as turbine" manufacturer that has furnished equipment for most of the in-conduit hydropower facilities visited by the feasibility study team (refer to Appendix D for site-specific information and list of visited facilities and the Post Site Visit Reports). Cornell products are commonly used for applications such as Awbrey Reservoir site. The operators at the sites visited reported no major maintenance for the units as long as they were regularly maintained per manufacturer's recommendations. The offering package includes the following list of components:

- Pump turbine, ductile iron fitted, lead free, horizontal direct drive configuration
- 74-kW , 1,200-rpm, 480-VAC, 60-Hz, three-phase induction generator
- 10-inch turbine inlet valve with hydraulic open, spring return actuator
- Custom 10-inch by 5-inch inlet cone reducer, flanged and coated, with pressure gauge
- Custom 8-inch by 10-inch outlet cone reducer, flanged and coated, with pressure gauge
- Custom HPU for inlet valve actuation, with solenoid valve hold
- Custom structural steel turbine/generator mounting frame
- Direct drive coupling set and steel drive guard
- Custom low-voltage switchgear to parallel the generator with the local electrical grid
- Custom controls panel to provide metering, utility grade protective relays, and feedback to the existing SCADA system

Further details of the offerings are found in Appendix B.

Note that InPipe Energy proposed a variable speed turbine, which could be further evaluated in a predesign of the selected improvements and bid against a fixed speed turbine design in an evaluated bid if deemed appropriate.

5.2.3 Estimated Energy Production

The Awbrey Reservoir facility will have flows sufficient to operate two turbines during maximum demand season and single turbine during the winter demand season. The flow available for power production remains consistent throughout a 72-hour period for both seasons, but the net head available for power production varies throughout same period as shown on Figure 5-10 due primarily to elevation variations in the downstream Awbrey Reservoir during the extended period simulation. The net head available for power production determines the amount of flow conveyed through the turbines. The turbine output is estimated using the Cornell 5 TR4 operation curve provided by the manufacturer (Figure 5-11). The turbine output varies in response to variable available net head and the characteristic curve of the turbine. Available net heads of 175 feet and 210 feet were assumed in the high and winter demand seasons, respectively, to estimate seasonal energy output and carry out further economic analysis. The estimated turbine output data are summarized in Table 5-3. The generator output is assumed to be 95% of the turbine output to account for energy loss between the turbine and the generator.

The proposed new Awbrey Reservoir FCV must remain operational with capacity of 12.3 cfs (7.95 million gallons per day [mgd], 5,520 gpm) continually as backup to any new in-conduit hydropower expansion. In addition, the new FCV facility must maintain its ability to process up to 12.3 cfs (7.95 mgd, 5,520 gpm) of flow to serve the reservoir while the in-conduit hydropower is offline. The centerline elevation of the turbine installation is critical as the outlet side of the turbine must maintain manufacturer-specified required net positive discharge head (NPDH) relative to the anticipated minimum reservoir elevation. The manufacturer recommends adding 5 feet to the operating-curve-required NPDH in practice, which brings the recommended NPDH to 19.5 feet during winter demand season and 15.5 feet during high demand season. Both these values indicate an allowable water surface in Awbrey Reservoir below the centerline of the turbine. The winter demand season requirement controls this design constraint. The downstream pipe must remain full and submerged below the reservoir water surface for proper turbine operation.

Overall, the turbine centerline elevation is directly related to the economic feasibility of the project mostly due to site construction constraints and costs. The power production estimate is based on the minimum operating tailwater elevation, which influences the available net head (independent of turbine centerline up to a maximum elevation above which the net head is reduced). The cost of in-conduit hydropower facility construction would vary based on the amount of excavation, required structural requirements for below-grade facilities, and length of required yard piping. Energy production at the Awbrey Reservoir site is estimated assuming such conditions can be satisfied to fully support and maximize the in-conduit hydropower generation potential. With 7 days of assumed in-conduit hydropower facility downtime during each of the two seasons to account for O&M activities, the Awbrey Reservoir site is expected to generate 612,000 kWh or more energy annually.

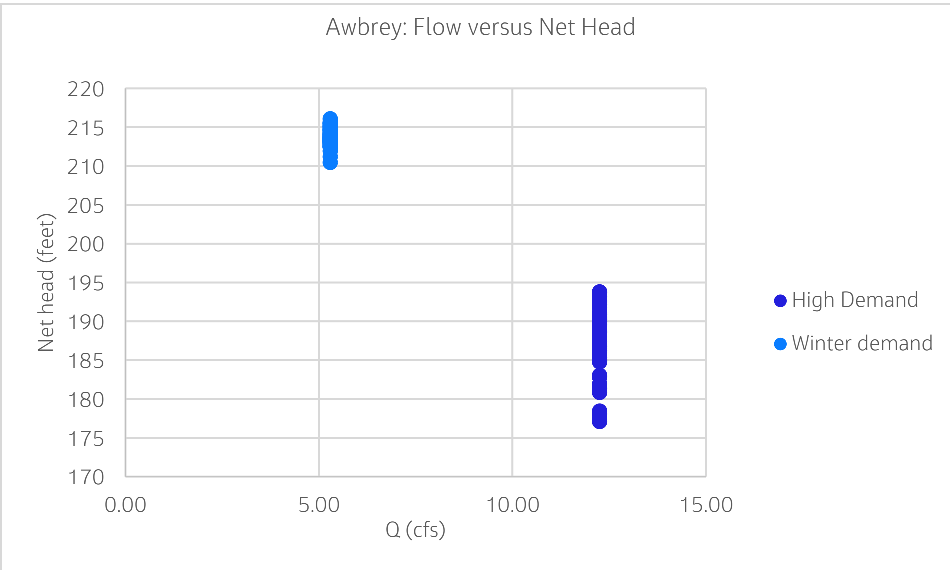

Figure 5-10. Flow Condition Summary at Awbrey Reservoir Site

Table 5-3. Seasonal Turbine Output Estimate at Awbrey Site

Seasons	Flow through FCV[a]	Flow through turbine(s)[b]	Flow total	Generator output (kW)[b]	Energy production estimate (kWh/6-month continuous season)[c]
Maximum demand	4.15 cfs/ or 2.68 mgd/ or 1,862 gpm	2 units combined, 8.10 cfs/ or 5.24 mgd/ or 3,636 gpm	12.25 cfs/ or 7.92 mgd/ or 5,498 gpm	86.6	365,000
Winter demand	0.74 cfs/ or 0.48 mgd/ or 332 gpm	1 unit, 4.55 cfs/ or 2.94 mgd/ or 2,042 gpm	5.29 cfs/ or 3.42 mgd/ or 2,374 gpm	58.7	247,000

[a] Total flow minus Turbine flow = FCV flow.

[b] Stated turbine output based on 95% of turbine vendor performance curve stated output.

[c] Awbrey site has approximate annual electrical demand of 265,000 kWh.

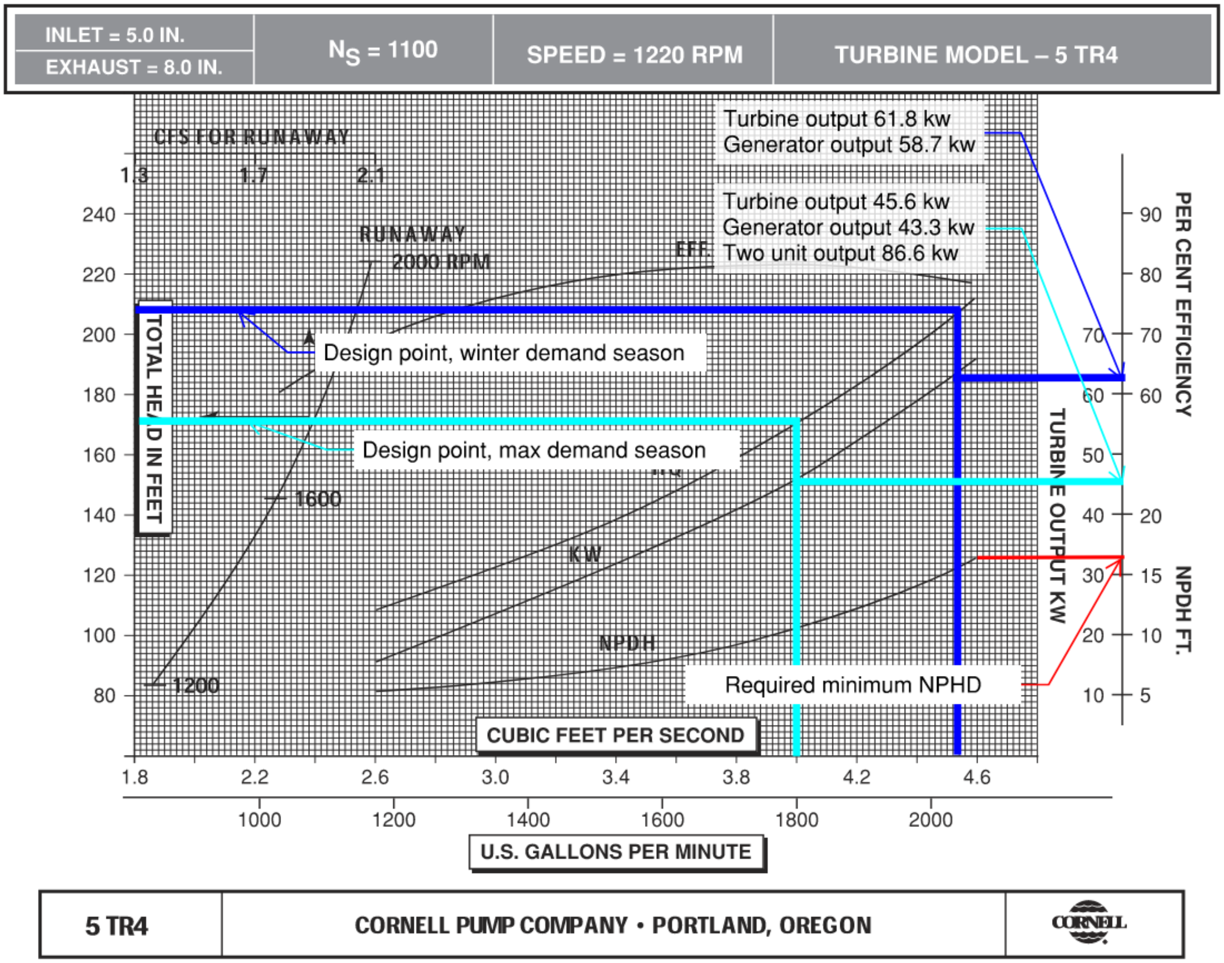

Figure 5-11. Turbine Vendor-provided Turbine Performance Curve with Key Design Conditions Noted

5.2.4 Proposed In-conduit Hydropower Site and Building Layout

As discussed in Section 5.2.1, the location, dimensions, and building details of the in-conduit hydropower facility depend on the final implementation of the FCV (altitude valve) building as a part of the planned Awbrey Butte Waterline Improvements project. The layout shown in Figure 5-12, Figure 5-13, and Figure 5-14 is based on the building dimensions, orientation, and equipment arrangement proposed in Figure 5-9.

The in-conduit hydropower facility is accessible from the valve building and from two separate exterior access doors. A coiling overhead door in conjunction with a 3-ton capacity bridge crane allows equipment access. The overall building footprint is 34 feet by 22 feet. Inside of the facility, two turbines outfitted with hydraulically actuated inlet valves are installed in parallel. Water is to be diverted from upstream of the planned FCV (altitude valve) and to be returned to the reservoir at the downstream end of the planned FCV (altitude valve). The HPU, control panel, and switchgear are installed along the wall.

Detailed building design is beyond the scope of this study, but the following elements would be important to consider in any basis of design document: Ventilation, heating, cooling; interior and exterior lighting requirements including natural lighting; crane and hoists; plumbing and drainage, code required ingress/egress and clear paths to exits.

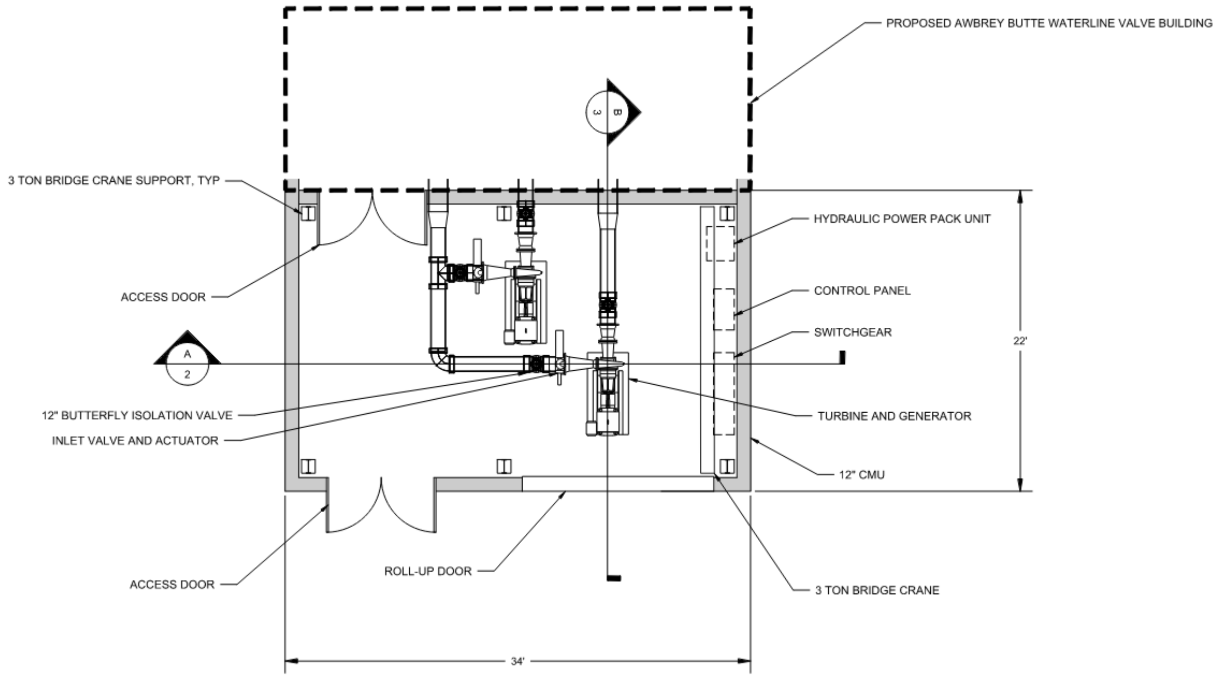

Figure 5-12. Plan View Building Layout of Proposed In-conduit Hydropower Facility

For an enlarged PDF version of the drawing, refer to Appendix B.

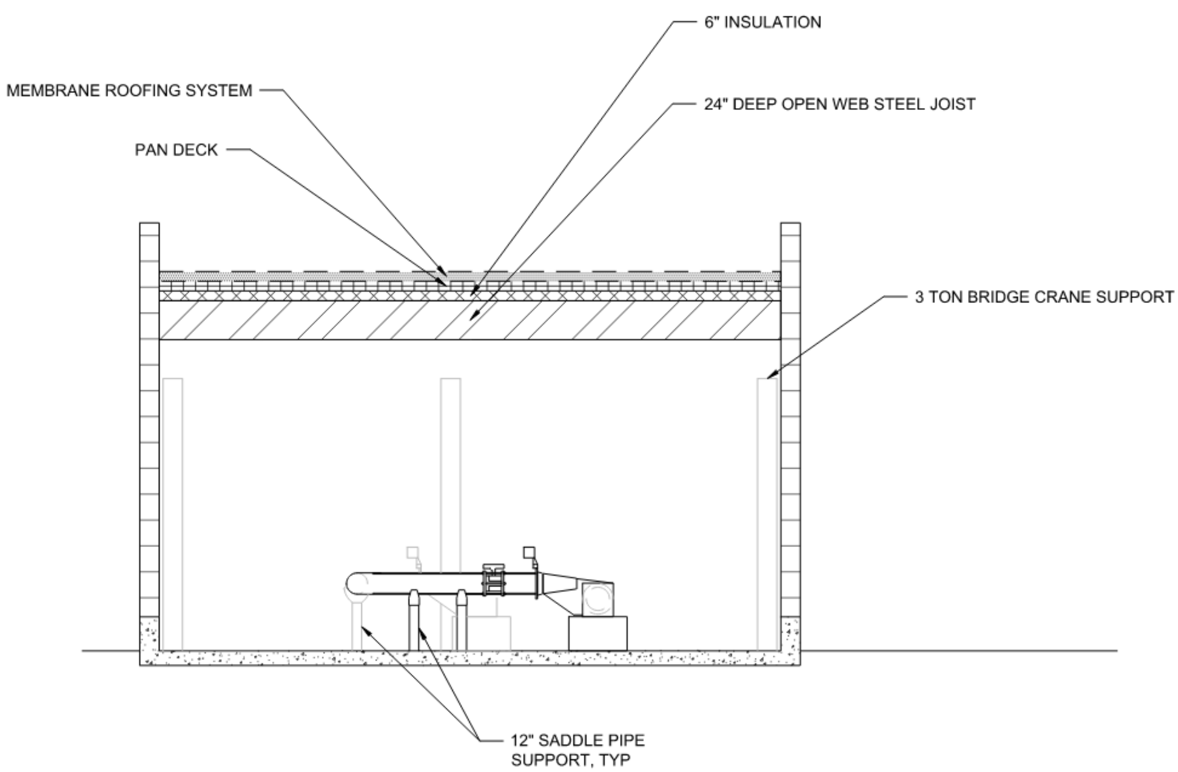

Figure 5-13. Building Layout of Proposed In-conduit Hydropower Facility, Section A

For an enlarged PDF version of the drawing, refer to Appendix B.

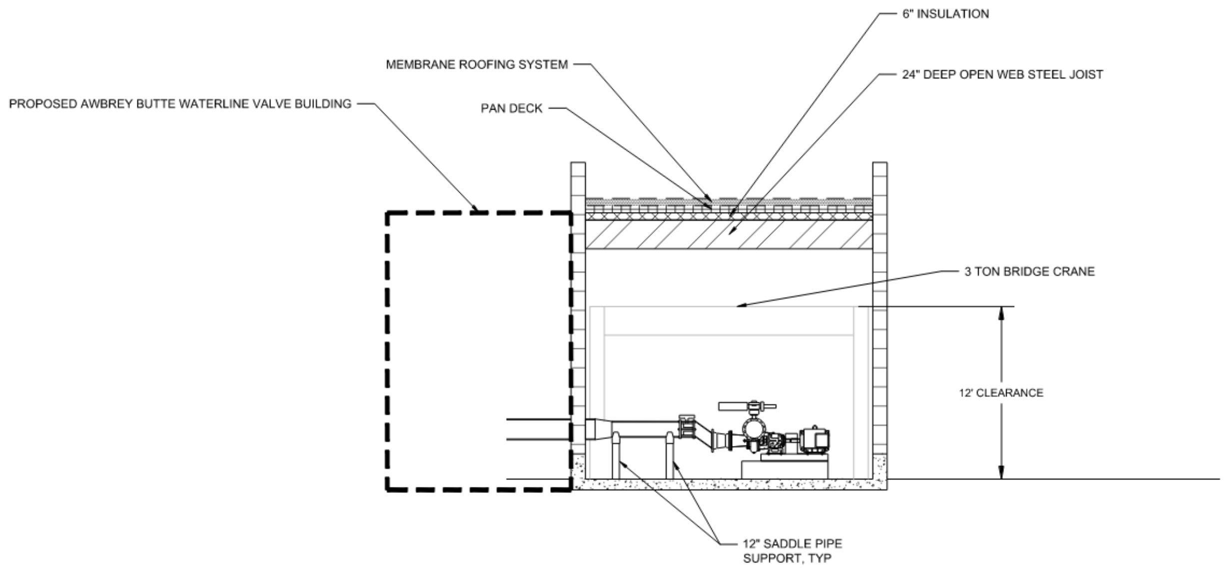

Figure 5-14. Building Layout of Proposed In-conduit Hydropower Facility, Section B

For an enlarged PDF version of the drawing, refer to Appendix B.

5.2.5 Electrical Interconnection

In 2019 the Awbrey Reservoir site had an aggregated power demand of 263,00 kWh for all meters. Based on the flows during this same time period, the City could expect power production from new turbines/generators on the order of 612,000 kWh, for an annual excess generation of about 350,000 kWh if all power demand onsite was satisfied with generation. Like Outback, this excess production will drive decisions about the most economically beneficial way to interconnect. Due to being less than 1,000 kW, Partial Requirements applicability criteria are not met so net metering or Power Purchase Agreement are the options for interconnection. The relatively consistent power generation will be balanced against periodic power demand from the intermittent booster pump station operation.

The existing electrical system at Awbrey Reservoir consists of a 1,000-A MCC. The main service disconnect is a 1,000-A circuit breaker. The MCC feeds three 200-horsepower motors on starters and two 7.5-kW heaters. In addition, the MCC feeds a low-voltage transformer and a 120/240-V single-phase panelboard located within the MCC. The electrical system also includes an existing PV system connected downstream of the utility meter. The PV system is available only when the electrical system is on utility power. After completion of the site visit by Jacobs, it was determined that the existing electrical equipment is outdated and unreliable, and good design practice recommends that it be replaced before making a new in-conduit hydropower connection.

The new electrical system recommended is shown Appendix B. The replacement electrical system will consist of a new service disconnect at the pump station that is connected to an automatic transfer switch (ATS). The ATS will be connected to the utility feed and a generator that is either portable or permanent. The ATS will then feed a 1,000-A rated MCC. The MCC will be located in the existing generator room. The MCC will feed the existing three 200-horsepower motors and the two existing 7.5-kW heaters. In addition, a new 25-kVA, 480-120/240-V dry type transformer and 120/240-V panelboard will be installed outside of the MCC. The two 74-kW in-conduit hydropower units will be located at the in-conduit Hydro/PRV Building and will each have their own circuit breakers. The in-conduit hydropower unit bus will then be connected to the MCC via a circuit breaker located at the MCC. Connecting the two in-conduit hydropower units to the MCC allows the electrical system to have flexibility. The electrical system can run on generator power via the ATS when there is a utility failure. Running the electrical equipment on in-conduit hydropower during a utility failure is not feasible because the in-conduit hydropower units are not large enough to start up a pump; ther efore, only operation on generator power will be possible during utility failure conditions. Even with provision of an onsite storage battery, the ability to start a pump from in-conduit hydropower operation is not expected to be possible. The electrical system recommendation provides a new reliable electrical system with a dedicated connection to the two in-conduit hydropower units.

The advantages of the new electrical system for Awbrey Reservoir are as follows:

- New and reliable electrical system.
- Flexibility in the electrical system to use in-conduit hydropower while on utility power.

5.2.6 Operations and Maintenance Requirements

O&M requirements for the Awbrey Reservoir site will be specific to the type of turbine provided, but are expected to be similar in scope and effort to the Outback turbine installation. See Section 5.1.8.

The anticipated O&M cost items are summarized in Table 5-4.

Some training efficiencies could be realized if the same staff are trained for O&M of all in-conduit hydropower facilities, although equipment types are quite different from the Pelton style turbine at Outback versus a pump-as-turbine system at Awbrey Reservoir. Estimating the incremental O&M costs for adding in-conduit hydropower to an existing site where staff members are already performing regular site visits is subjective and therefore inherently subject to interpretation.

Table 5-4. Anticipated O&M Cost Items at Awbrey Site (annual costs unless noted otherwise)

O&M daily operation, staff, $70/hour, 1 hour/day/year	$24,570
O&M yearly maintenance, manager, $90/hour, 80 hours/year	$7,200
O&M consulting, third party ($/year)	$2,000
O&M in-house, one-time, offsite education, three people	$7,500

5.2.7 Additional Considerations

The considerations discussed in Section 5.1.9 for the Outback site are also applicable to Awbrey Reservoir site, and are not repeated here for brevity.

5.2.8 Awbrey Reservoir Site Summary

Implementation of in-conduit hydropower at the Awbrey Reservoir site will yield a net export of power in the near term and long term. The decision to implement in-conduit hydropower at the Awbrey Reservoir site is a policy decision more so than an engineering or economic decision. As shown in the economic study described below, the costs outweigh the benefits unless incentives are provided that bring the cost/benefit ratio closer to 1.0.

If the policy decision indicates to proceed, then the City should implement pump-as-turbine and generator equipment, and integrate such design with the ongoing Awbrey Transmission pipeline improvement current under design and construction. The City has taken preliminary plans developed through this study and incorporated points of connection and layout allowances for implementation of this system.

Implementation of electrical Interconnection via NEM is most viable.

6. Economic Evaluation

The conventional economic viability for developing an in-conduit hydropower site is determined by comparing the present value of benefits, revenue from the sale of energy or monies saved by offsetting consumption, with the present value of costs, the capital cost for development, O&M costs, etc. This comparison can take the form of the net present value, benefits minus costs, or benefit-to-cost ratio (BCR). A detailed economic analysis, illustrating the costs, benefits, and economic feasibility of developing the sites, is attached to this report in Appendix G. The findings are summarized below.

6.1 Overview of Economic Analysis

Cost effectiveness is evaluated through a benefit cost analysis, comparing lifetime benefits and costs of the project on a net present value basis. Project benefits include the sale of generated electricity through a PPA with Pacific Power, the offset of onsite electricity use through a NEM arrangement with Pacific Power, or a combination of the two approaches through a Partial Requirements Generation agreement. Project costs include construction costs and other capital costs and startup costs, as well as annual O&M costs. Capital and operation incentives as well as the certification and sale of RECs associated with the project are also explored. The stream of benefits and costs over the life of the project are calculated on a net present value basis to account for the time value of money and to create a useful "apples-to-apples" comparison of benefits and costs. The resulting BCR indicates whether the project scenario is estimated to be cost effective (i.e., net benefits are greater than net costs when the BCR is greater than 1) or not (i.e., net costs are greater than net benefits when the BCR is less than 1) based on best available information.

General economic assumptions used to calculate net present value are outlined below:

- Useful Life—A useful life of 50 years is applied to this analysis based on direction from the City during initial project scoping, reflecting the City of Bend's 50-year planning horizon.
- Discount Rate—The analysis considers discount rates of 3% and 7% to represent the book ends of the range of reasonable rates. Different from the impact of inflation, the discount rate captures the economic phenomenon that 50 years from now $100 is not equivalent to $100 today. The difference represents the opportunity cost of capital. Federal projects require a discount rate of 7% in benefit cost analyses, but some federal agencies allow use of a 3% discount rate. These two book-end discount rates reflect the opportunity cost of private capital and the opportunity cost of consumption cash flows, respectively. Some states, like California, have a discount rate that falls between these two bookends. Since the State of Oregon does not have its own economic guidelines, the two federal project discount rates are used to explore cost effectiveness.
- Dollar Basis—All values presented in the analysis are in 2023 dollars. Any values used in the analysis based on other dollar years were converted to Q1 2023 dollars using the U.S. Bureau of Economic Analysis' Gross Domestic Product Implicit Price Deflator annual data and Q1 2023 quarterly data.

6.2 Project Scenarios

Seven project scenarios across two potential project locations were considered in this analysis. These seven project scenarios represent the combination of project location, electric configuration, and benefit approach (NEM, PPA, or Partial Requirements) that were deemed to have the most potential in the overall feasibility study. Refer to the overall feasibility study for a detailed description of the project scenarios.

One distinguishing feature of the seven project scenarios used in this analysis is whether the generated electricity would be sold to Pacific Power through a PPA or used to offset the City of Bend's onsite electricity use through a NEM agreement or a Partial Requirements Generation agreement. These three approaches come with their own benefit values and limitations and are discussed more under the "Energy Benefits" section below. Another distinguishing feature is whether a transformer is installed to either step up or step down the generated electricity.

The seven project scenarios included in this analysis are summarized as follows:

1. Outback Scenario 1A—PPA: Step-up transformer from 4,160 V to 12,470 V for direct connection with the electric grid. All generated electricity is sold to Pacific Power through a PPA.

2. Outback Scenario 1B—NEM, Aggregated: Step-up transformer from 4,160 V to 12,470 V for direct connection with the electric grid. All Outback meters would be aggregated by the utility for NEM offset.
3. Outback Scenario 2A—NEM, Limited: Step-down transformer from 4,160 V to 480 V for connection to WFF MCC. Generated electricity is used to meet electricity demand only at the WFF meter, and excess flows to the grid. Excess generated electricity (that is, greater than annual power demand at the WFF only, and not including wells or other power demand onsite) receives no economic benefit. Since Scenario 2B can be had for essentially no additional capital cost compared to Scenario 2A (yet capture benefits of power offset from wells and other power demand onsite), this option is less cost effective and included only for comparison sake.
4. Outback Scenario 2B—NEM, Aggregated: Step-down transformer from 4,160 V to 480 V for connection to WFF MCC. Generated electricity is used to meet electricity demand at the WFF meter, and excess flows to the grid. All Outback meters would be aggregated by the utility for NEM offset. Excess generated electricity (that is, greater than annual power demand at entire Outback site) receives no economic benefit.
5. Outback Scenario 3—NEM, Integrated: Utility meters at the Outback site are physically integrated. Generated electricity is used to meet electricity demand at the Outback site. Excess generated electricity (that is, greater than annual power demand at entire Outback site) receives no benefit.
6. Outback Scenario 4—Partial Requirements Generation Agreement: Utility meters at the Outback site are physically integrated. Generated electricity is used to meet electricity demand at the Outback site and any excess generated electricity (that is, greater than instantaneous power demand at entire Outback site) is sold to Pacific Power.
7. Awbrey Reservoir—NEM: Generated electricity is used to meet electricity demand at the Awbrey Reservoir Pump Station. Excess generated electricity (that is, greater than annual power demand at the Awbrey Reservoir site, including the pump station) receives no benefit.

Note that the difference between Outback Scenario 1A/1B and Outback Scenario 2A/2B is the electrical configuration. Outback Scenarios 3 and 4 physically integrate utility meters at the site so that more of the generated electricity can be used in-plant. In contrast, Outback Scenario 1 with an aggregated NEM scheme would offset electricity use from all Outback meters but it would not have the same resiliency benefits. Note that only Outback Scenario 1 is evaluated both with a PPA and a NEM arrangement, while the Awbrey Reservoir scenario is only evaluated with a NEM arrangement.

6.3 Assumptions

6.3.1 Capital Cost

Construction costs and other up-front capital costs were estimated for each of the seven project scenarios. Construction costs include all improvements required to construct an operating in-conduit hydropower facility at the existing sites, including in-conduit hydropower equipment, civil, structural, electrical, controls, electrical interconnection, as well as markup. The construction cost estimate is attached in Appendix H. No taxes are applicable to any of the contemplated projects and therefore not included. In addition to construction costs, engineering, legal, and administrative costs are estimated at 30% of construction costs consistent with City of Bend iWSMP estimating framework. Total capital costs are summarized in Table 6-1.. Construction costs shown in Table 6-1. are Class 5 estimates according to Association for the Advancement of Cost Engineering (AACE) *18R-97 Cost Estimate Classification System for the Process Industry* (2005). The AACE Class 5 estimates have an expected accuracy range of “50% higher than the listed mount and 30% lower than the listed amount” at the lower range and “100% higher than the listed mount and 50% lower than the listed amount” at the higher range. The presented estimate assumes the lower of the two ranges (+50% - 30%). These book-end estimates and their impact on cost effectiveness are explored in the analysis of possible future conditions.

Table 6-1. Capital Cost Estimates

	Outback Scenario 1A	Outback Scenario 1B	Outback Scenario 2A	Outback Scenario 2B	Outback Scenario 3	Outback Scenario 4	Awbrey Reservoir
Opinion of probable construction costs	$8,310,000	$8,310,000	$8,470,000	$8,470,000	$13,230,000	$13,230,000	$1,560,000
Engineering, legal, admin (30%)	$2,493,000	$2,493,000	$2,541,000	$2,541,000	$3,969,000	$3,969,000	$468,000
Startup, commissioning costs	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$12,000
Total capital costs	$10,823,000	$10,823,000	$11,031,000	$11,031,000	$17,199,000	$17,199,000	$2,040,000

In addition to construction and related costs, the analysis also considers the cost of financing construction of an in-conduit hydropower facility. It is assumed that capital costs will be financed over a 30-year period with payments beginning in 2025. Based on input from the City of Bend and recent trends in municipal borrowing rates, a range of 4.5% to 5% is used to estimate the cost of borrowing capital. The City of Bend has seen borrowing rates of 4.5% in past years, but uses a borrowing rate of 5% for their own financial planning. Therefore, 4.5% is used for the baseline estimate, but a rate of 5% is used to create more conservative estimates.

6.3.2 Capital Incentives

The City of Bend may be able to take advantage of capital incentives that the Oregon Department of Energy (ODOE) and others offer for hydroelectric generation facilities. Through the Community Renewable Energy Project Grant Program, ODOE offers grants to cover 50% of construction costs up to $1 million.

Multiple federal and state capital incentives are potentially available as described in Appendix F in the Hydropower Incentive Evaluation Memorandum. The capital incentive included in this analysis is the ODOE grant of $1 million.

Multiple other potential capital incentives are likely available, but to be conservative in cost-benefit calculations, and because the timing and availability of these funding resources is changing frequently, the ODOE grant is the only one included in offsetting capital cost, for purposes of economic analysis. As mentioned, it is a conservative approach, but clearly from now until time of project implementation, the City should vigorously monitor the available programs and develop a funding strategy prior to initiating project design and permitting.

The other mostly likely capital incentives are as follows:

- Energy Trust of Oregon – Implementation Grant
- FEMA BRIC grants

These and others are detailed in Appendix F. For each project scenario explored, results were calculated to show project cost effectiveness both with and without these capital incentives.

It is also assumed that there will be an additional cost associated with applying for this incentive program. Therefore, the cases that include a capital incentive also include this additional cost, estimated at 10% of the incentive amount, to account for grant writing or related consulting services or other resources needed to apply for the funding. This is a conservatively high value, and the City could potentially prepare all incentive applications with assistance only from technical specialists as required.

Since all seven project scenarios have capital costs over $2 million, it is assumed that in the with-capital-incentive case all six project scenarios could take advantage of the full $1 million capital incentive, with additional costs to pursue the incentive estimated at $100,000.

6.3.3 Operation and Maintenance Costs

O&M cost estimates were developed by the project team for each of the six project scenarios. These costs are summarized in Table 6-2.

Table 6-2. Summary of O&M Costs by Project Scenario

	Outback Scenario 1A (PPA)	Outback Scenario 1B (Aggregated NEM)	Outback Scenario 2A (Limited NEM)	Outback Scenario 2B (Aggregated NEM)	Outback Scenario 3 (Integrated NEM)	Outback Scenario 4 (Partial Requirements)	Awbrey Reservoir (NEM)
Annual O&M--Daily operation, staff, $70/hr, 1hr/day/year	$24,570	$24,570	$24,570	$24,570	$24,570	$24,570	$24,570
Annual O&M--Yearly maintenance, manager, $90/hr, 80hr/year	$7,200	$7,200	$7,200	$7,200	$7,200	$7,200	$7,200
Annual O&M--Consulting, third party ($/year)	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Total Annual O&M cost ($/year)	$33,770	$33,770	$33,770	$33,770	$33,770	$33,770	$33,770
One-time O&M--Inhouse, one-time, off-site education, 3 people	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500

6.3.4 Energy Benefits

Benefits of an in-conduit hydropower generation project are achieved through sale of the generated electricity to Pacific Power through a PPA, by offsetting the cost of onsite energy use through a NEM arrangement, or through a combination of the two in a Partial Requirements Generation agreement. The benefits associated with these approaches are discussed in the following sections. For all approaches, energy benefits are projected to begin in October 2026.

Power Purchase Agreement (PPA)

Under a PPA in Scenario 1A, it is assumed that all generated electricity from the project would be sold to Pacific Power at a rate established in their Standard Avoided Cost Rate Sheet, effective September 22, 2022. For detailed PPA Standard Fixed Avoided Cost Prices, see Appendix HG, Table 3. Note that for this analysis it is assumed that the Standard Fixed Avoided Cost Rate rather than the Renewable Fixed Avoided Cost Rate would be applied. Using the Renewable Fixed Avoided Cost Rate would depend on the transfer of ownership of any environmental attributes or green tags to PacifiCorp. Because the likelihood of this happening is uncertain, the Standard Fixed Avoided Cost Rate is applied in this analysis, and the financial impact of REC sales is considered separately. The Standard Fixed Avoided Cost Rate ranges from approximately 0.54 cent per kWh greater than the Renewable Fixed Avoided Cost Rate on-peak in 2026 to approximately 0.56 cent per kWh less than the Renewable Fixed Avoided Cost Rate on-peak by 2040. For off-peak periods, the Standard Fixed Avoided Cost Rates range from approximately and 1.14 cents per kWh to 1.35 cents per kWh less than the Renewable Fixed Avoided Cost Rate from 2026 to 2040, respectively.

Net Energy Metering (NEM)

Under the NEM approach, which applies to Scenarios 1B, 2A, 2B, and 3 of the Outback site and to the Awbrey Reservoir site, generated electricity will offset the City of Bend's energy bill. The energy benefit under a NEM approach is limited by the amount of energy used onsite through the meter designated for net metering. For example, even if the project produces 10,000 kWh of energy, if the meters to which net metering is assigned (including aggregated meters) only consume 6,000 kWh of energy, then the benefit of the project is limited to an energy savings of 6,000 kWh and no benefit would be received for the excess 4,000 kWh of generation.

Offset energy under a NEM approach is valued at the historical use and the historical average rate that the City of Bend pays for onsite energy use at the meter that the project is tied to. Historical use and historical average rates are based on billing information for 2020 and 2021. These are summarized in Table 6-3. Note that

the historical average rates vary across the different scenarios. Outback Scenario 2A has a slightly lower rate than the other Outback scenarios because in that scenario generated electricity would be used to offset the energy bill from a single, specific meter, so only that meter's historical rate is applied. For the other Outback scenarios, the average historical rate across all meters at the Outback site is applied. Outback Scenarios 1B, 2B, and 3 also have the potential to supply or offset the most energy demand—nearly twice as much as Outback Scenario 2A and 13 times as much as Awbrey Reservoir.

Table 6-3. NEM Historical Energy Use and Historical Rates

	Outback Scenario 1B (Aggregated NEM)	Outback Scenario 2A (Limited NEM)	Outback Scenario 2B (Aggregated NEM)	Outback Scenario 3 (Integrated NEM)	Awbrey Reservoir (NEM)
Historical annual energy use (kWh)	3,453,187	1,726,950	3,453,187	3,453,187	263,475
Projected 2025 energy production (kWh)	8,200,000	8,200,000	8,200,000	8,200,000	600,000
Historical average rate (cents/kWh)	9.69	8.91	9.69	9.69	12.78
Annual Cost of power offset by generation ($)	$335,000	$15000	$335,000	$335,000	$34,000

Partial Requirements Generation

A Partial Requirements Generation agreement was identified as a potential generation agreement approach for the Outback site only. Further confirmation with Pacific Power is required at the start of design and permitting to fully determine applicable rate scenarios because this is a relatively rarely applied generation agreement in Oregon. Specific discussions with Pacific Power near the end of this feasibility study confirmed that this kind of generation agreement is possible, but a specific rate sheet and terms and conditions were not provided by the time of publication of the study. Under the Partial Requirements Generation agreement, which applies to Outback Scenario 4, generated electricity would be used to offset onsite energy demand at the Outback site and excess generated electricity would be sold to Pacific Power. It is assumed that excess energy sold to Pacific Power would be sold at the non-firm qualifying facility (QF) rate. Because the non-firm QF rate depends on the real-time electricity market, a set price is not available. For this analysis, the PPA Standard Fixed Avoided Cost Price shown in Table 3 was used, with a 25% discount to account for the non-firm nature of the energy supply. It is assumed that physical integration of all meters would be required to make this approach effective. Further, this approach realizes resilience benefits from being able to power all Outback site infrastructure from the operating in-conduit hydroelectric generator.

6.3.5 Energy Generation Incentives

In addition to the benefits accrued from selling generated energy to Pacific Power or from offsetting the City's energy bills, an additional 1.8 cents per kWh is offered as an incentive created in 2023 through the Bipartisan Infrastructure Law for generation from hydropower development at non-powered dams and conduits through the Federal Hydroelectric Production Incentives program (EPA Act 2005, Section 242). This amount can be considered an additional energy benefit for all seven project scenarios. It is assumed that the program will run out of funds in October 2029. Therefore, in this analysis, when applied, this benefit is accrued from October 2026 through September 2029. The potential to earn this incentive reduces as the project implementation timeline extends into the future.

6.4 Analysis of Future Conditions

Future conditions are based on five basic parameters: discount rate, municipal borrowing rate, NEM price projection beyond 2035, PPA price projection beyond 2040, and capital costs. Table 6-4 shows the value ranges for each of these parameters and their impact on BCR. For all project scenarios, results are shown for all four possible incentive cases: no incentives, operating incentives only, capital incentives only, and both operating and capital incentives.

Table 6-4. Summary of Future Condition Parameters and their Impact on BCR

Parameter	Parameter settings	Parameter value	Notes
Discount rate (%)	Low end, high end	Low end = 3% High end = 7%	A lower discount rate discounts the long-term benefits stream less and results in a higher BCR
Municipal borrowing rate (%)	Low end, high end	Low end = 4.5% High end = 5%	A lower borrowing rate makes the project less costly in net present value terms, and increases the BCR
NEM price escalation (%)	High demand case, mid demand case, low demand case	High demand case =1.3% increase after 2035 Mid demand case = 2.3% increase after 2035 Low demand case = 2.9%	The low demand case projections result in higher NEM prices, and increases the BCR
PPA price escalation	Linear, constant	Linear = linear increase in prices after 2040 Constant = no increase in prices after 2040 in real terms	A linear projection results in higher PPA prices and increases the BCR
Capital cost ranges	Original estimate, low end, high end	Original estimate = original cost estimates Low end = 30% less than the original estimate High end = 50% greater than the original estimate	Lower costs increase the BCR

Based on the identified future condition parameters, a baseline condition, a high BCR, and a low BCR condition were identified and analyzed. In addition, the baseline future condition's sensitivity to municipal borrowing rate, energy prices, and reviewable energy certificates were explored. Detailed discussions are found in Appendix G.

A baseline set of future conditions was identified with the following parameters to represent the most likely future circumstances. For future energy prices, the more conservative parameter settings were used: high demand case for NEM price projection, and a constant PPA price projection. The 4.5% municipal borrowing rate was selected based on the City's experience with past borrowing. Capital costs were selected to be at or very close to the original estimates. Total project costs and total project benefits on a net present value basis are summarized in Table 6-5 and Table 6-6, respectively.

Table 6-5. Baseline Scenario Total Project Cost Summary

	Outback Scenario 1A (PPA)	Outback Scenario 1B (Aggregated NEM)	Outback Scenario 2A (Limited NEM)	Outback Scenario 2B (Aggregated NEM)	Outback Scenario 3 (Integrated NEM)	Outback Scenario 4 (Partial Requirements)	Awbrey Reservoir (NEM)
No Incentives	$13,446,711	$13,446,711	$13,689,708	$13,689,708	$20,918,862	$20,918,862	$3,185,939
Operating Incentives only	$13,446,711	$13,446,711	$13,689,708	$13,689,708	$20,918,862	$20,918,862	$3,185,939
Capital Incentives only	$12,395,283	$12,395,283	$12,638,280	$12,638,280	$19,867,434	$19,867,434	$2,134,511
All Incentives	$12,395,283	$12,395,283	$12,638,280	$12,638,280	$19,867,434	$19,867,434	$2,134,511

Table 6-6. Baseline Scenario Total Project Benefit Summary

	Outback Scenario 1A (PPA)	Outback Scenario 1B (Aggregated NEM)	Outback Scenario 2A (Limited NEM)	Outback Scenario 2B (Aggregated NEM)	Outback Scenario 3 (Integrated NEM)	Outback Scenario 4 (Partial Requirements)	Awbrey Reservoir (NEM)
No Incentives	$12,832,975	$11,082,147	$5,092,262	$11,082,147	$11,082,147	$17,433,110	$1,114,859
Operating Incentives only	$13,218,283	$11,244,253	$5,173,332	$11,244,253	$11,244,253	$17,595,216	$1,127,228
Capital Incentives only	$12,832,975	$11,082,147	$5,092,262	$11,082,147	$11,082,147	$17,433,110	$1,114,859
All Incentives	$13,218,283	$11,244,253	$5,173,332	$11,244,253	$11,244,253	$17,595,216	$1,127,228

6.5 Results

Results of this analysis indicate that under the given assumptions, Outback Scenario 1A is the project scenario with the greatest potential for cost effectiveness over the 50-year planning period. This is because all generated energy can be sold to Pacific Power for a benefit, and, unlike the other NEM scenarios, Scenario 1A also has the potential to be cost effective, particularly if capital incentives or both capital and operating incentives are in place. The limited NEM arrangement under Scenario 2A drastically reduces project benefits because only a small portion of the facility's in-conduit hydropower generating capacity would be used to offset energy use at the WFF. The high costs of fully and physically integrating the electricity meters under Scenario 3 and Scenario 4 also reduce the BCR significantly.

BCR results for the baseline future condition are shown in Table 6-7.

Table 6-7. City of Bend In-conduit Hydropower Feasibility Study Baseline Scenario Benefit-Cost-Ratios

	Outback Scenario 1A (PPA)	Outback Scenario 1B (Aggregated NEM)	Outback Scenario 2A (Limited NEM)	Outback Scenario 2B (Aggregated NEM)	Outback Scenario 3 (Integrated NEM)	Outback Scenario 4 (Partial Requirements)	Awbrey Reservoir (NEM)
No Incentives	0.95	0.82	0.37	0.81	0.53	0.83	0.35
Operating Incentives only	0.98	0.84	0.38	0.82	0.54	0.84	0.35
Capital Incentives only	1.04	0.89	0.40	0.88	0.56	0.88	0.52
All Incentives	1.07	0.91	0.41	0.89	0.57	0.89	0.53

The analysis explores how changes to the baseline future condition impact the BCR. The low and high estimates shown in Table 6-8 reflect the baseline scenario with municipal borrowing costs , NEM and PPA price forecasts as further described in the Appendix G. The municipal borrowing rate, and energy sale price forecasts are uncertainties that have a sizeable impact on cost effectiveness. For Outback Scenarios 1A, 1B, 2B, and 4, the high-end and low-end baseline future conditions tip the project from not being cost effective to being cost effective. For Outback Scenarios 2A and 3 and Awbrey Reservoir, the project is not cost effective even at the high-end baseline future conditions with more favorable long-term price estimates.

Table 6-8. Baseline Future Conditions Sensitivity Benefit-Cost Ratios (BCRs), using Original Capital Cost Estimates

	Outback Scenario 1A (PPA)		Outback Scenario 1B (Aggregated NEM)		Outback Scenario 2A (Limited NEM)		Outback Scenario 2B (Aggregated NEM)		Outback Scenario 3 (Integrated NEM)		Outback Scenario 4 (Partial Requirements)		Awbrey Reservoir (NEM)	
	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
No incentives	0.68	1.11	0.58	1.28	0.26	0.58	0.57	1.25	0.37	0.82	0.60	1.17	0.26	0.54
Operating incentives only	0.72	1.14	0.59	1.29	0.27	0.58	0.58	1.27	0.38	0.83	0.61	1.18	0.26	0.55
Capital incentives only	0.74	1.20	0.63	1.38	0.28	0.62	0.62	1.36	0.39	0.86	0.63	1.24	0.40	0.81
All incentives	0.78	1.23	0.65	1.40	0.29	0.63	0.63	1.37	0.40	0.87	0.64	1.24	0.41	0.81

6.6 Economic Analysis Conclusions

The analysis concludes that the following scenarios have the greatest economic feasibility under all future conditions examined over the 50-year planning period:

- Outback Scenario 1A with a PPA
- Outback Scenario 1B with NEM
- Outback Scenario 2B with Aggregated NEM
- Outback Scenario 4 with Partial Requirements Generation

Of these, only Outback Scenario 1A is estimated to be cost effective under the most likely future conditions, and even then only when capital incentives are in place. Pursuing recommended incentives improves the BCR for all project scenarios. All Outback scenarios make significant progress in meeting the City's Climate Action Goals. Awbrey Reservoir site and Outback Scenario 3 are only projected to be cost effective under the most generous future conditions but they do provide resiliency benefits that are not quantified in this analysis, and implementation helps meet the City's Climate Action Goals.

7. Conclusions and Recommendations

This feasibility study investigated the energy production potential, technical feasibility, and economic benefits of proposed in-conduit hydropower facilities at the Outback site, Awbrey Reservoir PRV site, Athletic Club PRV, and Overturf Reservoir PRV. The assessment provides a basis for the City to consider whether to proceed with developing in-conduit hydroelectric generation system at the four candidate sites. The study concludes the following:

- Two of the four candidate sites evaluated in Section 3, Preliminary Site Assessment, the Outback Site and Awbrey Reservoir Site, were found to be viable and recommended for further evaluation.

- The technical and economic feasibility of the Outback site and Awbrey Reservoir site were examined. The following information was developed:

  - Analyzing hydraulic conditions at each site allowed preliminary equipment selection and solicitation of budgetary quotations.

  - Feasibility study-level site layout and building layouts were developed.

  - Capital cost at each site was estimated based on the preliminary layout.

  - Institutional and regulatory features of in-conduit hydropower generation were investigated. Federal and local regulations, benefits, and permitting details were considered.

  - Economic feasibility of the two sites recommended for further evaluation was investigated while accounting for capital costs, ongoing O&M costs, economic incentives, and energy offsets and sale. Outback Scenario 1A with a PPA, Outback Scenario 1B with NEM, Outback Scenario 2B with aggregated NEM, and Outback Scenario 4 with Partial Requirements Generation agreement have the greatest economic feasibility under all future conditions examined over the 50-year planning period. Awbrey Reservoir site and Outback Scenario 3 are only projected to be cost effective under the most generous future conditions. All in-conduit hydropower implementation is consistent with the City's Community Climate Action Plan.

The study recommends the following:

- At the Outback site, Implement a single, dual nozzle horizontal Pelton turbine and generator. Pursue and implement "Partial Requirements" interconnection agreement with Pacific Power at the Outback site, with generator connected to new medium voltage switchgear as described in Outback

Scenario 3 electrical configuration. This approach will realize resiliency benefits and maximize value of all power produced.

- At the Awbrey Reservoir site, implement two pump-as-turbine generation units, and upgrade existing electrical infrastructure. The existing electrical equipment is outdated at the Awbrey Reservoir site and unreliable, and good design practice recommends that it be replaced before making a new in-conduit hydropower connection. Establish a net energy metering agreement with Pacific Power.

- For all turbine/generator purchases, consider an evaluated bid equipment proposal including life cycle costs, minimum performance standards and power production performance testing requirements (including consideration of variable speed turbine(s) for Awbrey Reservoir site). Consider operating performance guarantees with incentives or penalties associated with meeting specified requirements in field testing after startup.

- Pursuing the recommended economic incentives and federal benefits is necessary to realize the economic feasibility of in-conduit hydropower at the Outback site. Pursuing additional incentive opportunities concerning the Awbrey Reservoir site may allow the overall benefit of the project nearly equivalent to the cost of the proposed project.

- Establish and maintain an in-conduit hydropower implementation schedule, including permitting and licensing. Permitting would include Deschutes County land use, Oregon Water Resources Department water rights, and FERC Qualifying Facility notice of intent to construct.

- Coordinate closely with the planned capital improvement projects at the Outback WFF and the ongoing design of the Awbrey Butte Waterline Improvements. These are essential to the future success of the projects. Specific risks for coordination include equipment and piping elevations, and physical layout of the facilities to coordinate with planned and future improvements. Coordination between all relevant parties will maximize power production, facilitate optimal O&M access, and integrate the proposed in-conduit hydropower facilities into the City's water filtration and distribution systems.

- Conduct a surge analysis to thoroughly examine the risks associated with normal and emergency shut down conditions of the hydropower generation at Outback site and Awbrey Reservoir site.

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