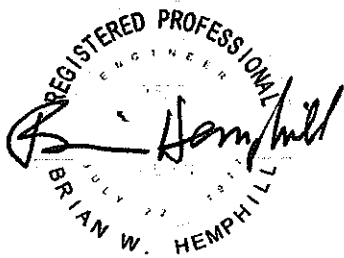




# City of Beaverton

## RENEWABLE ENERGY FEASIBILITY STUDY

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EXPIRES: 2/1/2011

Final Technical Memorandum

October 2009

# HDR

1001 SW 5<sup>th</sup> Ave, Suite 1800  
Portland, OR 97204  
503-423-3700

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# Executive Summary

This report evaluates two potential opportunities for energy recovery projects within the City of Beaverton's water distribution system. The two systems are (1) the altitude valves supplying the Sexton Mountain Reservoir, and (2) ASR #2.

## Sexton Mountain Altitude Valve Station

The energy recovery system for this system would consist of a turbine installed on the pipeline that feeds the altitude valve station (AVS), which would capture about 60-70 psi of lost pressure for flows going into the 15 MG reservoir. A new small building would be built to house the turbine and associated valves and controls

Table ES-1 shows the total estimated capital cost with and without incentives along with revenue projections. Even with the highest level of incentives the payback period exceeds 30 years, which is well beyond an acceptable level.

**Table ES-1: Simple Payback Analysis for Sexton AVS Turbine**

	Rate, \$/kWh	Un-Incentivized	Incentivized
Estimated Project Capital Costs		\$ 817,000	\$ 461,600
2010 Annual Revenue	\$0.048	\$ 7,300	\$ 7,300
2028 Annual Revenue	\$0.110	\$ 18,900	\$ 18,900
Average Revenue	\$0.085	\$ 13,900	\$ 13,900
Simple Payback Period, years		59	33

## ASR # 2

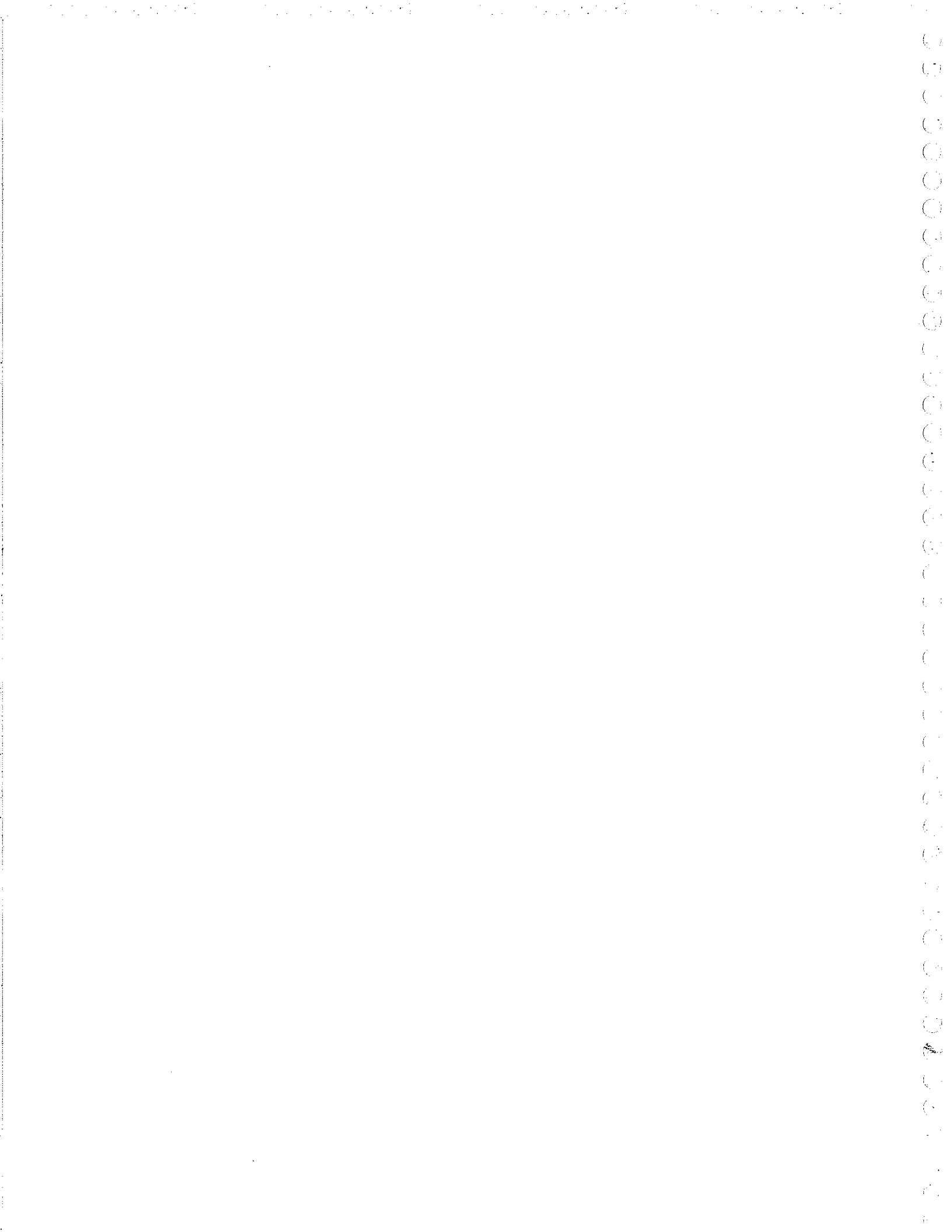
ASR #2 is a turbine pump well located near the Sorrento Reservoir. The energy recovery potential for this installation occurs during the period in which water is fed down the hole in the aquifer storage mode.

The best technique for this installation is "regenerative braking", in which the existing pump is allowed to spin backward under the influence of the falling water. The motor operates as a generator, and the power is conditioned through a motor inverter and line inverter and fed back into the local power grid.

The cost analysis is provided in Table ES-2. Again, the payback periods exceed acceptable levels.

**Table ES-2: Simple Payback Analysis for ASR #2 Regenerative Turbine**

	Rate, \$/kWh	Un-Incentivized	Incentivized
Estimated Project Capital Costs		\$ 225,000	\$ 127,000
2010 Annual Revenue	\$0.048	\$ 1,440	\$ 1,440
2028 Annual Revenue	\$0.110	\$ 3,300	\$ 3,300
Average Revenue	\$0.085	\$ 2,550	\$ 2,550
Simple Payback Period, years		88	50



# **Section 1 - Introduction**

## **1.1 Project Background**

The City of Beaverton water supply system serves a population of more than 60,000 people. The system is supplied from the Joint Water Commission, and also has interties with the Tualatin Valley Water District, the City of Tigard, and the City of Portland.

As is common with larger distribution systems, there are certain locations at which excess water pressure is available that is currently lost through pressure reducing devices or other means. In Beaverton's case, two of these locations are sites of aquifer storage and recovery (ASR) systems. At these locations treated water is fed through wells to underground aquifers for storage during the winter months, and then pumped out for use during the periods of higher demand during the summer.

This study was undertaken to provide an evaluation of the feasibility of capturing lost energy and converting it to electric power through use of mini-hydropower devices. The study was set up to conduct a detailed evaluation of one pressure reducing valve (PRV) station and one ASR site, following a review of alternative sites as described in Section 1.3.

The study was funded in part with Oregon State Lottery Funds administered by the Oregon Economic and Community Development Department through an agreement with the City of Beaverton.

## **1.2 Hydropower Overview**

Hydropower facilities within water distribution systems operate similarly to larger scale hydropower systems located on rivers. They use a turbine and a generator to convert available excess water pressure into electricity. This excess water pressure is typically defined as pressure in water distribution systems that is higher than needed or desirable to serve customers. Without an energy recovery (hydropower) system, this excess pressure is typically reduced through PRVs, which reduce the pressure by creating turbulence and friction head losses within the PRV.

There are notable differences in the energy recovery technology that can be applied to pressurized distribution systems versus surface water open channel discharges. In pressurized distribution systems, there cannot be a free, open discharge from the turbine because it is necessary to maintain a closed system that provides needed pressure to serve the downstream customers.

There is a wide variety of turbines that can be used in these systems. "Reverse-running pumps" are used for most distribution system applications. These are basically off-the-shelf water pumps that are operated in reverse so that the motor running backwards becomes a generator. These are used because they are economical and can operate with good efficiency.

Each turbine has a characteristic operating range in terms of flow and pressure drop (also known as "head"). Each turbine has a range of minimum to maximum operational head and flow. The turbine power generation efficiency is typically highest near the middle of this range and is lower at each end of the range.

Each distribution system also has a range of flows and available excess pressures that vary throughout the day and throughout the seasons. Beyond these diurnal and seasonal changes, there are often changes from year to year as demands grow or systems are reconfigured. Generally, because of system hydraulics there is less available excess pressure when flows are higher, and vice-versa.

Because the flow through turbines has a limited range, it is also necessary to operate PRVs in parallel with the turbines to provide the full capacity range for the station to meet system demands under all conditions. In addition, most installations also employ a PRV downstream of the turbine to provide additional pressure reduction beyond what the turbine can provide if needed.

Selecting the most efficient turbine/PRV system for any particular installation must take into account both the range and duration of flows and pressures. Smaller turbines could be operated during a higher percentage of low to high flow conditions but may be unable to capture all available energy from the higher flow conditions. Larger turbines may operate during a smaller percentage of the range of flow conditions (e.g. not be able to operate during lower flows), but could potentially generate more energy over the year because they can operate during higher flows. The selection process is a matter of simulating the range of pressures (heads) and flows through alternative configurations and sizes of prospective turbines to compare estimated system performance over an extended period and calculate the overall electrical energy production. The value of that electrical energy is then compared with the cost of installation of that turbine, and to calculate a net return on investment.

The full power generating potential of the turbine system is obtained only when the available head and flow are within the operation range of the turbine. During other conditions, either the turbine cannot operate, or part of the flow is being bypassed, with its energy lost in parallel or downstream PRVs.

### **1.3 Selection of Sites for Evaluation**

The project scope called for review of three PRV locations and three ASR locations to establish the two sites to be evaluated in detail.

#### **1.3.1 Selection of the PRV Study Site**

Three locations of pressure reducing valves were considered – known as the Shaw Street PRV, the 141<sup>st</sup> and Allen PRV, and the Sexton Mountain altitude valve (a form of PRV).

The 141<sup>st</sup> and Allen PRV was eliminated because of its location in a busy street, with no feasible location for installation of a turbine facility. The Shaw Street PRV was

eliminated because it has an average flow of only about one-third of the Sexton Mountain altitude valve, and because of the more difficult construction conditions.

### **1.3.2 Selection of the ASR Study Site**

The three ASRs within the city system were considered for detailed evaluation. ASR #1 and ASR #2 are both located at the Sorrento Water Works Facility and operate in the same aquifer, so the hydraulic conditions are similar. Of these two, ASR #2 is the more attractive candidate for retrofit because of its higher capacity (and therefore higher potential for energy recovery) and the relative ease with which the station could be modified for energy production.

ASR #4 has a similar capacity to ASR #2 and has similar operating characteristics. ASR #2 was selected because the installed down-hole valve system was considered to be more amenable to conversion to a generation facility from a construction standpoint.

## Section 2 - Sexton Mountain Altitude Valve Evaluation

### 2.1 System Description

At the Sexton Mountain complex, water from the JWC is supplied to a 15 MG reservoir. Supply pressure is higher than necessary, and excess pressure is depleted through an altitude valve station (AVS) that automatically maintains a set elevation in the reservoir by throttling incoming flows.

Downstream of the reservoir on the same site there is a booster pumping station that draws from the reservoir and supplies water to the Sorrento High Pressure System and to Cooper Mountain. There are plans to improve this system by changing the piping so that the pumps are fed directly from the JWC supply line, thereby bypassing the altitude valves and the reservoir. This will greatly reduce the power consumption of those pumps. Reducing flow through the altitude valve station also reduces the volume of water available for hydropower energy recovery. This reduction in flow volume was accounted for in the performance projections as described below.

### 2.2 Flow and Head Projections

HDR was provided with hourly operating data for year 2008 for the Sexton Mt. AVS. During that period the flow averaged 2.03 mgd (1,400 gpm). The 2008 seasonal trends for flow and pressure drop at the AVS are presented in **Figure 1**. Flow through the station increases during the peak demand months in the summer. As expected, available head (pressure drop) through the station declines as flow increases.

As described above, hourly operating data for the Sexton Mt. pump station for the same period was also provided. To arrive at projected energy recovery from a turbine installed ahead of the AVS, the flow from the pump station was subtracted from the AVS flow. Figure 1 shows the pump station flows.

Power generated by a turbine is a function of the instantaneous flow and head (pressure drop) available. The estimates of revenue associated with power generation presented in this report are based on hourly historical and projected flow and pressure data to capture diurnal and seasonal variations that affect turbine performance. To determine the estimated revenue stream during a turbine life cycle, flow projections for future years assumed a one percent per year growth rate.

To account for changes in pressure with varying flows, a linear regression was developed between flows and available pressure. The derived curve and the equation are shown in Figure 2. Applying the linear regression equation to hourly projected flows, the future pressure drops could be calculated.

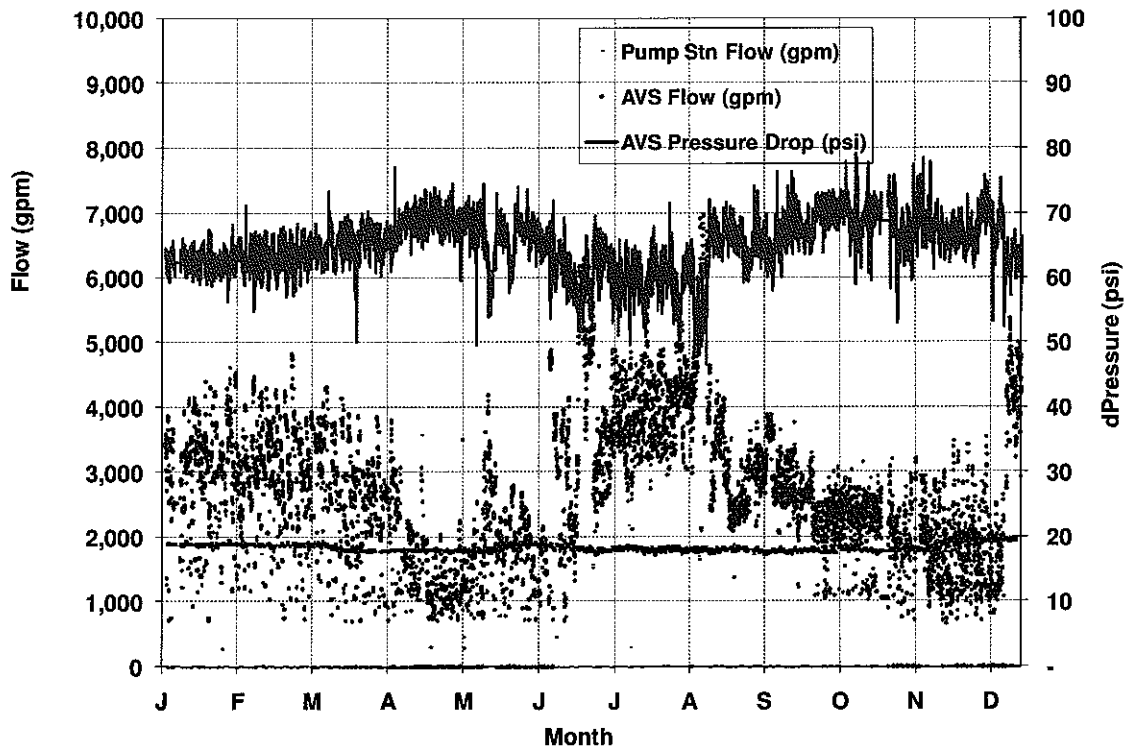


Figure 1. Sexton Mt. AVS and Pump Station 2008 Operating Conditions

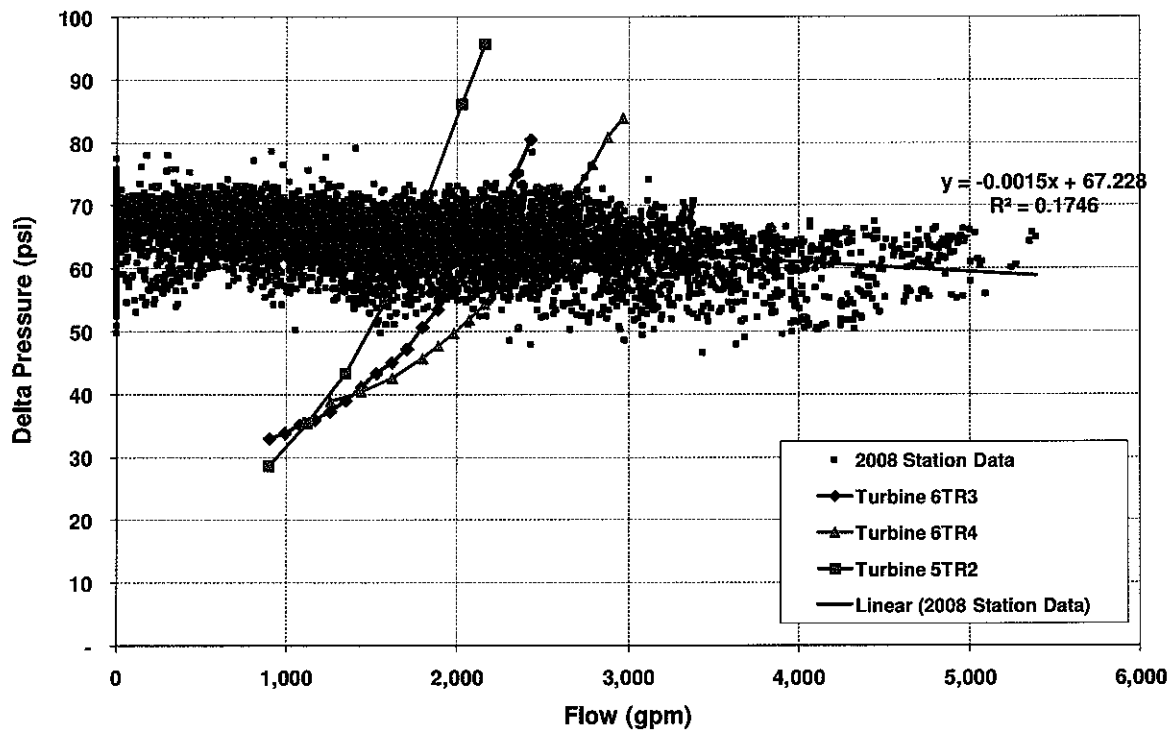


Figure 2. Sexton Altitude Valves Operation and Turbine Curves

## 2.3 Hydroelectric Energy Generation Model

Energy generation was calculated hourly using historical 2008 and projected flow and pressure data through 2028. The analysis assumed realistic performance from a turbine using the following methods:

- It assumed that the turbine does not generate power when the minimum pressure requirement (the lowest point on the turbine curve) is not met. However all of the selected turbines could operate at the minimum observed pressures.
- When the flow and pressure drop exceed the turbine capacity, the power is calculated using the maximum turbine flow and head capacity.
- When the flow rate is not sufficient to adequately reduce the downstream pressure, the downstream PRV serves to burn off the remaining head that the turbine is unable to remove at that point on its curve.
- Also, the analysis assumes that the turbine is operated to its full capacity at any time the hourly flow and pressure conditions are met or exceeded. Other factors, such as lack of automatic control, lack of reliable flow control, and system operation, will inevitably reduce total energy production somewhat.

## 2.4 Evaluation of Turbine Alternatives

### 2.4.1 Turbines Considered

Three potential turbines were evaluated, as listed in **Table 1**. These three represent a range of turbine sizes that fit within the most frequent operating points of the station.

**Table 1: Sexton Mt. PRV Station Turbines Alternatives**

<b>Alternative</b>	<b>Turbine Flow Range (gpm)</b>	<b>Generator Capacity (kW)</b>
1) Cornell Turbine 6 TR4	1200-3000	81
2) Cornell Turbine 6 TR3	900-2500	59
3) Cornell Turbine 5 TR2	900-2200	62

The curves for these three turbines are shown over a plot of the 2008 operating data in Figure 2.

### 2.4.2 Energy Generation

The analysis results for energy generation during the 20-year period 2009 through 2028 for each turbine alternative are presented in **Figure 3**. This shows the total energy in

kilowatt hours (kWh) projected to be produced during that period.

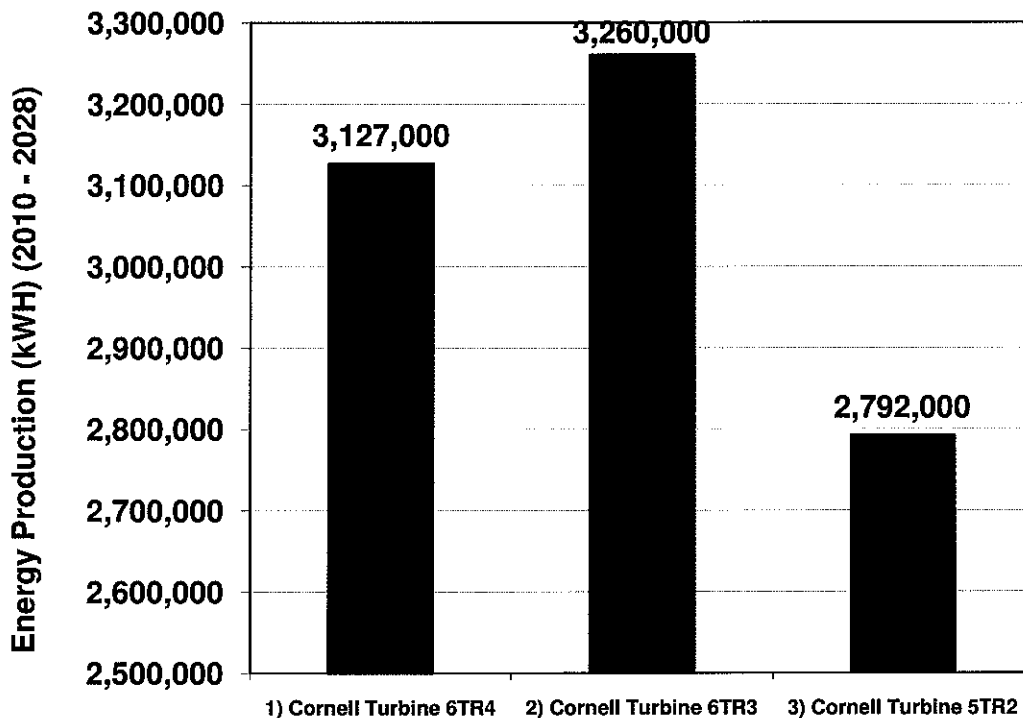


Figure 3. Estimated Energy Recovery (kWh) 2010 – 2028 for Turbines

Since the Model 6TR3 is the smallest (and lowest cost) turbine and also provides the highest energy production, it was selected as the representative turbine.

## 2.5 Proposed System Configuration

Figure 4 shows a sketch of an arrangement employing the 6TR3 turbine in the Sexton Mountain system. The feed pipe would be tapped upstream of the AVS with two new tees and valved so that the turbine system could be bypassed. As described above, the turbine must be installed with PRVs both downstream and in parallel with the turbine.

Normally all flow would be directed to the turbine system, and then into the AVS. The turbine, valves, and PRVs would be housed in either a vault or in a structure at grade. Because of the density of buried piping on site it was assumed that it would be a new building at grade.

## 2.6 Economic Analysis

### 2.6.1 Capital Cost

A planning level construction cost estimate was developed for the system shown in

Figure 4. The items included in the cost estimate include:

- Utility building to house the turbine system
- Turbine purchase and installation
- Piping and valve modifications
- Electrical improvements to deliver power to PGE
- Mechanical painting and supports

The costs were then adjusted to account for contractor overhead and profit, general conditions, contingency, and permitting.

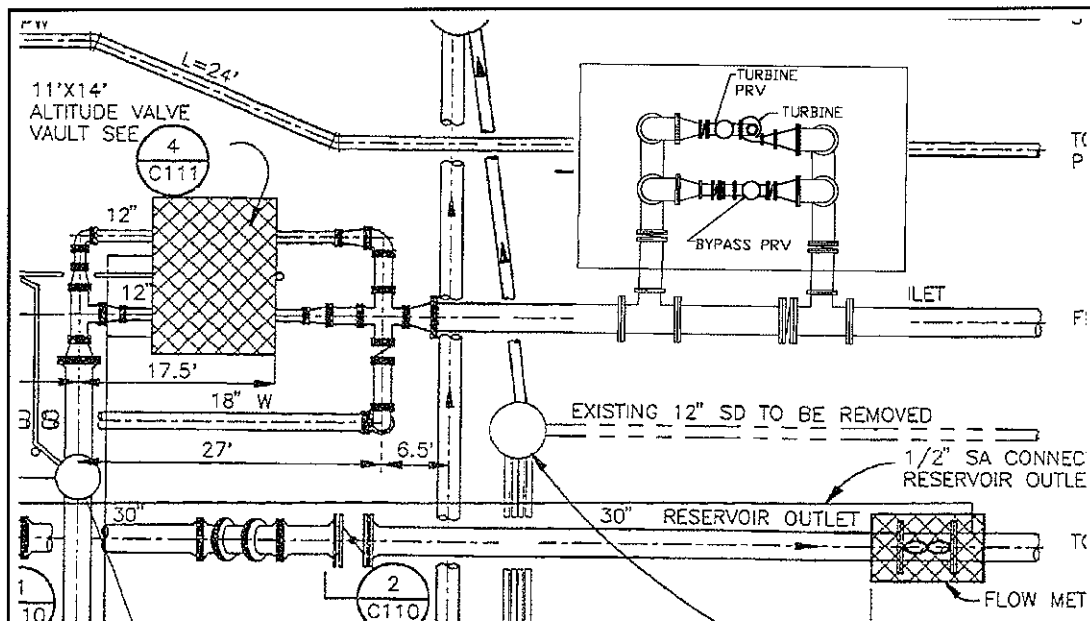


Figure 4. Layout of Turbine System at Sexton Altitude Valve Station

The estimated system capital cost is shown in **Table 2**.

There are financial incentives available for implementing renewable energy projects. The Business Energy Tax Credit provides an incentive of 33.5 percent of the project cost. Although the City of Beaverton does not pay taxes, it is possible to find a buyer and sell the tax credit created by this project. The Energy Trust of Oregon may provide additional subsidies. For the purposes of this study, an assumption was made that an additional 10 percent of the project cost is available from ETO.

**Table 2: Capital Cost Summary for Sexton AVS Turbine**

Description	Takeoff Quantity		Total Cost/Unit	Total Amount
<b>Division #2 - Site Work</b>				
Misc Site Work Allowance	1	LS	\$10,000	\$10,000
Turbine Building	500	SF	\$150	\$75,000
<b>Division #9 - Finishes</b>				
Painting Allowance	1	LS	\$5,000	\$5,000
<b>Division #11 - Equipment</b>				
Cornell Turbine	1	EA	\$104,000	\$104,000
<b>Division #15 - Mechanical</b>				
30" x 24" tee	2	EA	\$15,000	\$30,000
24" Pipe	20	LF	\$180	\$3,600
24" Elbow	4	EA	\$7,100	\$28,400
30" BFV	1	EA	\$6,000	\$6,000
24" BFV	2	EA	\$5,000	\$10,000
12" BFV	2	EA	\$1,700	\$3,400
24" Tee	2	EA	\$10,300	\$20,600
12" PRV	2	EA	\$14,300	\$28,600
24" x 12" Reducer	2	EA	\$3,700	\$7,400
12" x 6" Reducer	1	EA	\$700	\$700
Pipe Support Allowance	1	LS	\$3,000	\$3,000
<b>Division #16 - Electrical</b>				
Power Conduit and Wire	1	LS	\$20,000	\$20,000
Modifications to Existing Power Distribution Eqpmt	1	LS	\$2,500	\$2,500
Control Conduit and Wire	1	LS	\$5,000	\$5,000
Coordination Fees from PGE for Net Metering Agmt	1	LS	\$5,000	\$5,000
Install Generator SWGR/Controls Package	1	LS	\$5,000	\$5,000
Additional Circuit Breaker to Generator SWGR	1	LS	\$2,500	\$2,500
<b>Sexton AVS Turbine System SUBTOTAL</b>				<b>\$375,700</b>
<b>Additional Costs</b>				
<b>Description</b>	<b>Rate</b>		<b>Amount</b>	<b>Totals</b>
Contractor OH	10%		\$37,570	
Contractor Profit	5%		\$18,785	
Mob/Bonds/Ins.	6%		\$22,542	
General Conditions	3%		\$11,271	
			\$90,168	\$465,868
Contingency	30%		\$139,760	\$605,628
Engineering and Administration	30%		\$181,689	
Permitting	LS		\$30,000	
			\$211,689	\$211,689
<b>Total Capital Cost</b>				<b>\$817,000</b>

## 2.6.2 Value of Produced Energy

A detailed calculation of energy production was made as described in part 2.4.1 above. The value of the produced power was estimated based on Portland General Electric Company "SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION"<sup>1</sup>. This publication lists projected rates for power purchases by PGE from qualifying facilities. The rates vary by time of day, by month, and by year. For example, for year 2010 for the month of February (in the middle of the storage season), the off-peak (10:00 PM – 6:00 AM) rate is \$0.043/kWh, and peak periods the rate is \$0.048/kWh. By year 2020 these rates increase to \$0.068/kWh \$0.105/kWh, respectively.

For these estimates, the weighted average rates for November-May for the period of the table (through 2028) were used. This value is \$0.085/kWh. This simplified method was used since the payback analysis is based on a similarly simplified method.

## 2.6.3 Carbon Offset Potential

Based on Portland General Electric's methods, the estimate power savings equates to an annual carbon offset of 39 tons CO<sub>2</sub> per year the period studied (2010-2028).

## 2.6.4 Summary of Economic Analysis

Table 3 3 shows the un-incentivized and incentivized capital costs, the estimated annual returns from power sales, and the resulting payback periods. It is a simplified analysis, ignoring operation, maintenance, and replacement costs for the equipment.

**Table 3: Simple Payback Analysis for Sexton AVS Turbine**

	Rate, \$/kWh	Un-Incentivized	Incentivized
Estimated Project Capital Costs		\$ 817,000	\$ 461,600
2010 Annual Revenue	\$0.048	\$ 7,300	\$ 7,300
2028 Annual Revenue	\$0.110	\$ 18,900	\$ 18,900
Average Revenue	\$0.085	\$ 13,900	\$ 13,900
Simple Payback Period, years		59	33

As shown in the table, even with full incentives the simplified payback period is over 30 years. Typical acceptable simplified payback periods for a project like this would be on the order of ten years or less. Based upon this criterion, this project is not cost-effective.

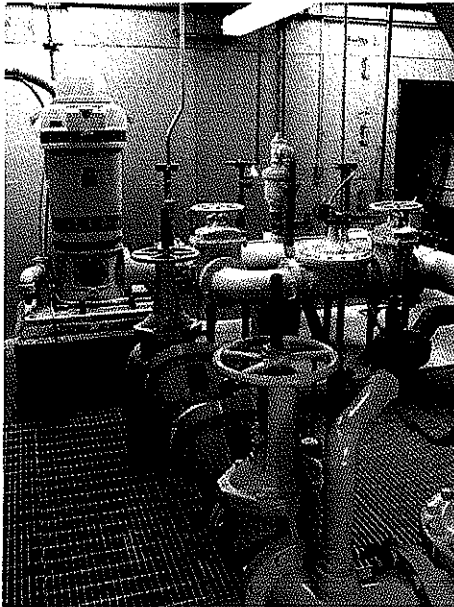
<sup>1</sup> [http://www.portlandgeneral.com/about\\_pge/regulatory\\_affairs/pdfs/schedules/sched\\_201.pdf](http://www.portlandgeneral.com/about_pge/regulatory_affairs/pdfs/schedules/sched_201.pdf).  
City of Beaverton  
Renewable Energy Feasibility Study  
October 2009

## Section 3 - ASR #2

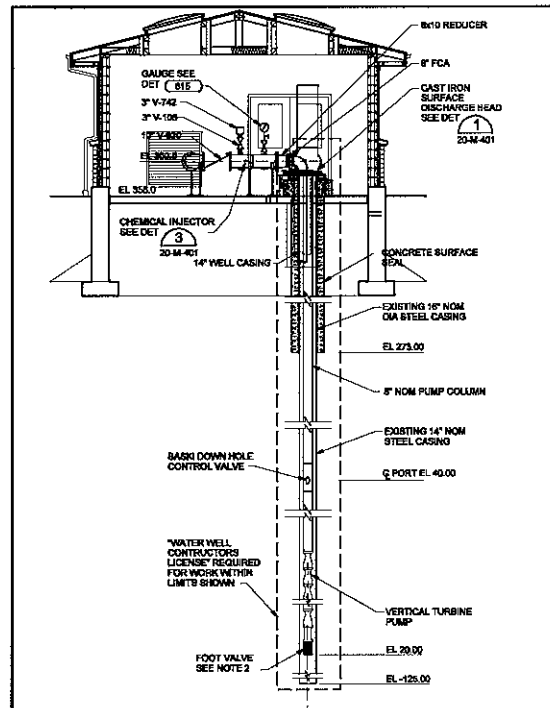
### 3.1 Description of Hydropower Alternative

ASR #2 was selected for evaluation for potential energy recovery. This turbine pump well, located near the Sorrento Reservoir, has a nominal output capacity of about 700 gpm, with a storage supply capacity of about 1,400 gpm.

A photograph of the well house interior is shown in **Figure 5** and a section of the well house and well is shown in **Figure 6**.



**Figure 5. ASR #2 Well House**

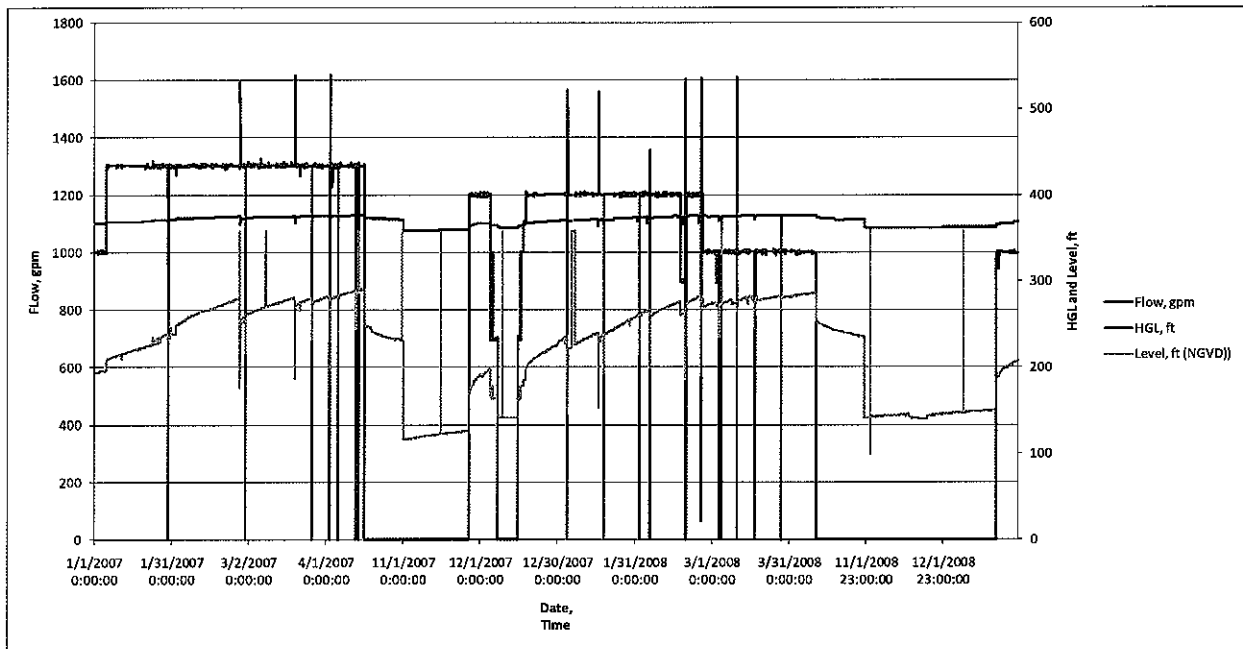


**Figure 6. Section of ASR #2 Well**

The well is installed with a 14-inch casing with an 8-inch pump column. The well house is at grade at elevation 358. The casing extends about 480 feet down to elevation -125. The pump column is fitted with a Baski down-hole control valve at elevation 40. The foot of the turbine is located at elevation 20.

The well is operated in storage mode (i.e., with system flows being sent down the column) during the wet season from approximately mid- to late-November through mid-April. Operation data provided for this analysis is shown in **Figure 7**. The red line shows the hydraulic grade line at the station as measured with a pressure gauge. The blue line is the flow being directed down the well in gallons per minute, and the green line shows the measured water surface elevation in the groundwater. The water level rises

approximately 100 feet over the winter season as a result of mounding of the injected water.



**Figure 7. ASR #2 Performance 2007-2008**

The energy recovery potential for this installation occurs during the period in which water is fed down the hole in the aquifer storage mode. The principle is that the water has more than sufficient head to make its way down the hole and into the aquifer, and the excess pressure could be captured and converted to energy.

There are two potential methods for capturing excess energy, described in the sections below. The first is to install a turbine at the well house, and the second uses the existing well pump itself as the turbine device.

### 3.2 Surface Turbine

This system would employ a turbine installed in the well house, which would capture available pressure at the surface. The discharge pressure from the turbine system would be at or near zero, and it would flow by gravity down the column, through the Baski valve and into the aquifer. This installation would be similar to, although smaller than, the one shown for the Sexton Reservoir facility in the previous section, incorporating a bypass PRV and another PRV downstream of the turbine. It is the same system that is being proposed for installation by the City of Pendleton, Oregon.

Unfortunately, this set of operating conditions does not match commercially available off-the-shelf turbines. While flows are adequate, there is only about 10 to 15 feet of head available, which is well below the range of available conventional turbines.

In spite of this limitation, preliminary estimates were developed for potential power generation. These were based on available flows and head, and assumed a typical turbine efficiency of 80 percent and a net turbine “availability” factor of 50 percent. This factor accounts for the potential power that is not captured due to flows that bypass the turbine or from pressure that is taken up by the downstream PRV. Both of these conditions are a result of operating conditions that do not fall directly on the turbine curve.

These provided a net estimate of only about 3,000 kWh/year, with approximate revenue of \$150/year at \$0.05/kWh. Since the equipment installation would easily exceed \$100,000, this option does not appear to be cost-effective.

### **3.3 Regenerative Braking System**

The second configuration would use the existing well pump itself as the turbine/generator device. This incorporates a technique called “regenerative braking”, in which the existing pump is allowed to spin backward under the influence of the falling water. The motor operates as a generator, and the power is conditioned through a motor inverter and line inverter and fed back into the local power grid. No modifications to the pump or motor are required, and it only requires installation of the electrical conditioning equipment. This technology is used in a lot of industrial applications, including braking systems on local MAX trains.

This system is able to use a greater portion of the overall available pressure head since the pump is located far below the surface. In addition, all flows through the pump contribute to power generation (as opposed to the conventional reverse-running pump described above in which a portion of head and/or flows is wasted). However, this is counteracted by a relatively inefficient generating system – reverse running turbines in this mode develop an efficiency only equal to about half of the efficiency achieved in the normal pumping mode. The net effect is that the resulting efficiency from water to power is approximately 40 percent, which is the value used to estimate the power generation.

The existing configuration would require modification for this system to work, since during the aquifer storage mode flows exit the column through the Baski valve and do not flow through the pump. It would be necessary to move the valve to a position below the pump bowl.

It is not known if the existing pump can safely be operated in the reverse mode without damage or excessive wear. This would need to be verified with the pump manufacturer before proceeding with this plan.

#### **3.3.1 Project Capital Costs**

The estimated costs for providing a regenerative braking system are shown in **Table 4**. The same incentives described in the previous section could apply to this system as well, as discussed below.

**Table 4: Capital Cost Summary for ASR #2 Regenerative Braking System**

Description	Total Amount		
Regenerative braking system, installed			\$50,000
Pull column and move Baski valve			\$25,000
<b>Electrical</b>			
Power conduit and wire			\$10,000
Control conduit and wire			\$3,000
Coordination Fees from PGE for Net Metering Agmt			\$5,000
<b>SUBTOTAL</b>			<b>\$93,000</b>
Description	Rate	Amount	Totals
Contractor OH	10%	\$9,300	
Contractor Profit	5%	\$4,650	
Mob/Bonds/Ins.	6%	\$5,580	
General Conditions	3%	\$2,790	
		\$22,320	\$115,320
Contingency	30%	\$35,600	\$149,920
Engineering and Administration	30%	\$44,975	
Permitting	LS	\$30,000	
		\$74,975	\$211,689
<b>Total Capital Cost</b>			<b>\$225,000</b>

### 3.3.2 Value of Produced Energy

As described above, the 24 months of hourly system operating data were analyzed to develop estimates of the power that would be generated for this configuration. Because of the variation in the groundwater level, the available head during this period ranged from 85 to 240 feet, with an average of about 150 feet. The total flow over the two year period was about 400 million gallons.

This analysis calculated an average annual power production of about 30,000 kWh. The revenue projections listed below were based on the PGE Schedule 201 as described in Section 2.6.2.

### 3.3.3 Carbon Offset Potential

Based on Portland General Electric's methods, the estimate power savings equates to an annual carbon offset of 7 tons CO<sub>2</sub> per year.

### 3.3.4 Summary of Economic Analysis

Table 5 shows the un-incentivized and incentivized capital costs, the estimated annual returns from power sales, and the resulting payback periods. This is a simplified analysis that doesn't consider maintenance costs and doesn't account for the fact that

the projected remaining life of the well is less than 50 years.

This estimated simple payback period is about 50 years, even with incentives. As mentioned earlier, typical acceptable simplified payback periods would be on the order of ten to fifteen years or less. Based upon this criterion, this project is not cost-effective.

**Table 5: Simple Payback Analysis for ASR #2 Regenerative Braking System**

	Rate, \$/kWh	Un-Incentivized	Incentivized
Estimated Project Capital Costs		\$ 225,000	\$ 127,000
2010 Annual Revenue	\$0.048	\$ 1,440	\$ 1,440
2028 Annual Revenue	\$0.110	\$ 3,300	\$ 3,300
Average Revenue	\$0.085	\$ 2,550	\$ 2,550
Simple Payback Period, years		88	50

## **Section 4 - Permitting Issues**

### **4.1 Permitting Overview**

This section provides a summary of issues relating to permitting of a newly developed hydroelectric generating facility. Please refer to the related Memorandum issued by GSI Water Solutions, Inc. dated September 11, 2009 for additional details.

Under the authority of the Federal Power Act (FPA), as amended, the Federal Energy Regulatory Commission (FERC) has the exclusive authority to regulate non-federal hydropower projects located on navigable waterways or federal lands, or connected to the interstate electric grid (FERC, 2004).

The Oregon Water Resources Department (OWRD) is responsible for ensuring that sufficient and sustainable water supplies are available to meet current and future needs. Under Oregon law, all water is publicly owned. With some exceptions, cities, farmers, factory owners and other users must obtain a permit or water right from the OWRD to use water from any source.

The City of Beaverton's proposal to construct a small hydropower facility in conjunction with improvements to the City's water system would require FERC, OWRD, local, and Portland General Electric (PGE) involvement and approval to generate electrical energy and distribute that energy via the interstate electric grid.

### **4.2 Exemption from FERC Licensing**

#### **4.2.1 Exemption Criteria**

An exemption from FERC licensing can be obtained for municipal hydroelectric facilities that utilize a conduit. Section 4.30(b)(28) of FERC's regulations defines "small conduit hydroelectric facility" as an existing or proposed hydroelectric facility that is constructed, operated, or maintained for the generation of electric power, and includes all structures, fixtures, equipment, and lands used and useful in the operation or maintenance of the hydroelectric facility, but excludes the conduit on which the hydroelectric facility is located or the transmission lines associated with the hydroelectric facility and which:

- Uses for electric power generation the hydroelectric potential of a conduit;
- Is located entirely on non-federal lands;
- Has an installed capacity of 40 MW or less in the case of a municipal water supply project;
- Is not an integral part of a dam;
- Discharges the water it uses for power generation either:
  - Into a conduit;
  - Directly to a point of agricultural, municipal, or industrial consumption; or
  - Into a natural water body if a quantity of water equal to or greater than the quantity discharged from the hydroelectric facility is withdrawn from that water body downstream into a conduit that is part of the same water supply system

- as the conduit on which the hydroelectric facility is located; and
- Does not rely upon construction of a dam, which construction will create any portion of the hydrostatic head that the facility uses for power generation unless that construction would occur for agricultural, municipal, or industrial consumptive purposes even if hydroelectric generating facilities were not installed.

Both of the proposed small hydroelectric projects would meet all of the criteria for a Conduit Exemption.

#### **4.2.2 Exemption Application Process**

The Application for Conduit Exemption must include:

- An Introductory Statement;
- Exhibits A (Project Description), E (Environmental Report), F (Engineering Drawings), and G (Map of the Project and Boundary);
- An appendix containing documentary evidence showing that the applicant has the real property interests required; and
- Identification of all Indian Tribes that may be affected by the project.

The procedural steps associated with a Conduit Exemption application are similar to those for an application for license and require a three-stage consultation process that includes (FERC, 2001):

1. Notice of Intent and initial information
2. Studies and draft application preparation, and
3. Application filing and acceptance by the FERC Commission.

After comments and recommendations from fish and wildlife agencies have been received regarding the proposed project, the FERC staff will conduct an environmental analysis based upon the existing record, but will not prepare an Environmental Assessment (EA) or Environmental Impact Statement (EIS) per the National Environmental Policy Act (NEPA). Conduit Exemptions are Categorically Exempt (CE) from the preparation of an EA or EIS under 380.4(a) (14). The FERC will then decide if the exemption will be granted. Upon granting an exemption from licensing, the FERC will set certain terms and conditions. If an application for a Conduit Exemption is denied, the applicant can convert the application into an application for license (FERC, 2001).

### **4.3 State Permitting Requirements**

If electrical energy generated by the hydroelectric facility is incorporated into an existing delivery system and the water used is either certificated or decreed (i.e., "perfected") for municipal use and the electrical energy is an ancillary benefit, then a Develop Hydroelectric Use as Part of an Existing Certificated Water Right Application (Oregon Revised Statute (ORS) 543.760 - 543.990) would need to be applied for from the

OWRB.

#### **4.3.1 Oregon Revised Statutes (ORS) Chapter 543 – Hydroelectric Projects**

Under ORS 543.765 Certificate to use water for hydroelectric purposes; expedited application process the holder of a water right may apply to the OWRD for a certificate to use water for hydroelectric purposes within an artificial delivery system under the applicant's existing water right. If the proposed hydroelectric project qualifies for a FERC exemption, the applicant may use the expedited application process under this section. The OWRD will then issue a final order and certificate to use water for hydroelectric purposes upon making a final determination that the proposed hydroelectric use does not impair, or is not detrimental to, the public interest in the manner provided in ORS 537.170 (8).

#### **4.3.2 Application Process**

The Application to Develop Hydroelectric Use as Part of an Existing Certificated Water Right must include:

- The certificate number, or decree reference if no confirming certificate has been issued, of the applicant's existing water right associated with the proposed hydroelectric project.
- A copy of a FERC exemption application, if applicable.
- A proposed schedule of annual water use and an estimate of the maximum power generation of the proposed hydroelectric project.
- A statement by the applicant that the amount of water used by the proposed hydroelectric project will not exceed the amount authorized and used under the applicant's existing water right for beneficial use without waste.
- A statement that the applicant owns or otherwise controls the water conveyance system.
- A map or drawing and all other data concerning the proposed hydroelectric project, as may be prescribed by the department. The map or drawing must be of sufficient quality and scale to establish the location of the existing point of diversion and the proposed location of the hydroelectric facility.
- If the water to be used for the proposed hydroelectric project is delivered by a public entity other than the applicant for a certificate under this section, a statement from that entity that the entity will be able to deliver water as described in the application.
- Evidence that the water has been used over the past five years according to the terms and conditions of the applicant's existing water right described in paragraph (a) of this subsection.

The OWRD will provide notice to both the Oregon Department of Fish and Wildlife (ODFW) and the public, and provide a 30-day period for public comment. The OWRD would then issue a final order and certificate to use water for hydroelectric purposes upon making a final determination that the proposed hydroelectric use does not impair, or is not detrimental to, the public interest in the manner provided in ORS 537.170 (8).

## 4.4 Local Permitting Requirements

The City of Beaverton would be the local approval agency for site development and building permits. Under the City of Beaverton Code (BC), Chapter 9.05 Site Development, 9.05.025 Permit Exemptions, a permit provided for in BC 9.05.020 shall not be required for the following; (A) Site development work in connection with a public improvement or public work for which inspection is provided by the City or other public agency as approved by the city engineer in an area other than a Significant Natural Resource Area.

An Electrical Permit may need to be obtained because the City of Beaverton requires electrical plans for “complex structures” to be reviewed and approved before issuance of an electrical permit. For the purpose of this rule, “complex structures” means an electrical installation involving one or more of the following:

- Ampacity:
  - A service or feeder beginning at 400 Amps where the available fault current exceeds 10,000 Amps at 150 Volts or less to ground or exceeds 14,000 Amps for all other installations; or
  - Installation of a 75 KVA or larger separately-derived system as defined in Article 100 of the National Electrical Code (NEC); or
  - Addition of a new motor load of 100 HP or more; or
  - A service or feeder rated at 600 Amps or over.
- Voltage: More than 600 supply volts nominal.

Neither of the projects under consideration would be classified as “complex structures”.

## 4.5 Portland General Electric (PGE)

PGE will purchase power from customers who install eligible renewable generation up to 1.5 MW in size. Eligible renewable generation is defined by the Public Utility (PU) Code Section 399.12. PU Code Section 399.12 defines renewable generation as meeting Public Resources Code 25741, which describes renewable generation as an in-state facility using biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current.

Once customers who meet the eligibility criteria and PGE both sign the Power Purchase Agreement and the customers interconnect to PGE’s grid, PGE will pay them for energy they generate but do not apply to serve on-site load. The tariffs that are available to customers are provided in Schedule E-PWR for public water and wastewater customers.

## 4.6 Permitting Summary Table

**Table 5** at the end of this section provides a summary of permit types typically required

for the presented alternatives in this hydroelectric feasibility study.

## **4.7 References**

FERC (Federal Energy Regulatory Commission)

2001 Hydroelectric Project Handbook for Filings Other Than License and Exemptions. Washington D.C. April, 2001.

2004 Handbook for Hydroelectric Project Licensing and 5 MW Exemptions from Licensing. Washington D.C. April, 2004.

2009 Small/Low-Impact Hydropower Projects, Tri-fold Brochure. Website: <http://www.ferc.gov/industries/hydropower/gen-info/licensing/small-low-impact/small-hydro.pdf>. Accessed August 6, 2009.

**Table 5: Federal, State, Local, and Selling Permitting Requirements for Small Hydroelectric Projects**

Permit	Submittal Requirements	Permit Fees	Approx. Timeline	Notes
<b>FERC</b>				
<b>SMALL CONDUIT HYDROELECTRIC FACILITY EXEMPTION</b>				
	<p>Introductory Statement, as described in 18 CFR Part 4 §4.92(b)</p> <p>Exhibits A, E, F, and G, as described in 18 CFR Part 4 §4.92(c), (d), and (f)</p> <p>Appendix containing documentary evidence that the applicant has the real property interest required under § 4.31 (b)</p> <p>Identification of all Indian tribes that may be affected by the project</p>	<p>Fish and wildlife agency reimbursement fees as estimated during comment period.</p>	<p>18 to 24 months</p>	<p>The length of time may be longer or shorter depending on the complexity of the environmental issues involved. Successfully expedited projects may have exemptions issued in as little as 10 months (FERC, 2009).</p>
<b>OWRD</b>				
<b>DEVELOP HYDROELECTRIC USE AS PART OF AN EXISTING CERTIFICATED WATER RIGHT</b>				

Permit	Submittal Requirements	Permit Fees	Approx. Timeline	Notes
	<ul style="list-style-type: none"> <li>Application form</li> <li>Permit fee</li> </ul>	\$500	90 days	<p>Application also needs to include:</p> <ul style="list-style-type: none"> <li>The certificate number or decree reference of existing water right.</li> <li>Copy of FERC exemption application, if applicable.</li> <li>Proposed schedule of annual water use and an estimate of the maximum power generation of the proposed hydroelectric project.</li> <li>A statement that the amount of water used by the proposed hydroelectric project will not exceed the amount authorized and used under the applicant's existing water right for beneficial use without waste.</li> <li>A statement that the applicant owns or otherwise controls the water conveyance system.</li> <li>Evidence that the water has been used over the past five years according to the terms and conditions of the applicant's existing water right.</li> </ul>

**City of Beaverton**  
**BUILDING/LAND USE PERMITS**

	<ul style="list-style-type: none"> <li>No local land use or building permits needed if contained within existing structure and use and electricity is sold to a franchise.</li> </ul>			
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**ELECTRICAL PERMIT (MAY BE NEEDED)**

	<ul style="list-style-type: none"> <li>Electrical Permit Application Form</li> <li>Site Plans</li> </ul>	\$637 (max)	30 to 45 days	
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**PGE**  
**PGE (SMALL POWER PRODUCTION [1000 KW OR LESS])**

**HDR**

Permit	Submittal Requirements	Permit Fees	Approx. Timeline	Notes
	<ul style="list-style-type: none"> <li>• Project Developer's Facility Description</li> <li>• Schedule 201 or Negotiated Power Purchase Agreement Attachment 2</li> <li>• Interconnection Request Application</li> </ul>	No Fee	90 days	

