Summary Report
Investigation of Multiple Benefit Water Storage Projects in the Mid Columbia

Reconnaissance Level Study

HDR, Chelan PUD to Washington Department of Ecology Office of the Columbia River

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Office of Columbia River

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Executive Summary

In 2009, Chelan PUD, with funding from the Washington State Department of Ecology Office of the Columbia River (OCR), hired HDR to conduct an investigation of sites that could be suitable for multiple purpose water storage facilities. Specifically the study investigated sites that may be suitable for a facility that would be operated as both a pumped storage facility and a water storage facility with periods of drawdown to provide downstream water benefits. HDR developed cost estimates for nine sites and identified potential sources of revenue. These were used as inputs for an economic model developed for this study. The model was used to assess the different sites under several operational scenarios. The model was also used to segregate water storage and pumped storage costs and pump storage revenues and to analyze alternative methods to allocate costs and revenues between the two different uses. This was done in order to determine if a site could be made more economically attractive to both an entity interested in water storage and an entity interested in the products generated from pumped storage. Results indicate the total quantified benefits of the projects may range from $1.1 billion to $3.7 billion with total costs ranging from $1.2 billion to $3.9 billion. The total cost per acre-foot of water ranged from $21,000/AF to $70,000/AF. Analysis conducted on segregating costs and revenues, and investigating alternative allocation scenarios suggests running a pumped storage facility for water storage benefits may enhance the overall economics of the project from both a pumped storage and water storage perspective. But this would be highly dependent on the operational requirements added to this joint use facility to meet the water storage features, balanced with how much of a cost burden the water storage business line is able to bear.

Background

In 2008, Bonneville Power Administration integrated less than 2,000 mW of renewable power into the BPA transmission grid. By 2010 this increased to approximately 3,000 mW and is expected to grow to almost 10,000 mW by 2016 although not all of it is expected to be in the BPA balancing authority.[1] This large increase in the amount of intermittent renewable energy can pose challenges to the transmission grid due to quick changes in the amount of energy that is being produced. Although integrating wind is being accomplished with current regional resources (the hydro system and natural gas peaking plants), a time may come where additional resources, such as large scale energy storage facilities (pumped storage), are needed to provide balancing services. Given the current resource mix used to integrate wind and the constraints on the hydro system, there is the question that if new integrating resources are needed, does the region want to accomplish this with new fossil fuel facilities, or would there be value in integrating one renewable resource with another renewable resource such as a pumped storage facility.

Negative energy prices are another challenge that can occur when wind power projects can continue to produce power profitably even when market prices decrease to less than $0/mWh. This is caused by the tax structures that have been implemented to incentivize the development of intermittent renewable resources through the utilization of Production Tax Credits. However, these market conditions may also

[1] http://transmission.bpa.gov/PlanProj/Wind/documents/Wind_Forecast_Graph_2015-September2010.pdf

provide an opportunity to increase revenues through the sale of ancillary services, although these markets are immature at this time. To better prepare for both the risks and opportunities the challenges of integrating intermittent renewable generation presents to the region, Chelan PUD conducted a high level pumped storage study in 2008.

In June 2008, Devine Tarbell and Associates Inc. (now HDR/DTA) was retained by Chelan PUD to perform a reconnaissance level "site identification and screening" study to evaluate potential opportunities for constructing a new, yet to be sized pumped storage project within Chelan and Douglas counties. The study provided rough order of magnitude (ROM) cost estimates. Early in the study, HDR/DTA concluded that that areas located adjacent to the Columbia River and Lake Chelan offered the most potential for pumped storage development. Five sites were identified that ranged in size from 20,000 to 80,000 acre-feet.

In 2006, the OCR was directed by the Washington State legislature to identify new sources of water in order to fulfill requests for new water rights and to transform interruptible water rights into uninterruptible water rights in the Columbia River Basin. Funding allocated to OCR from the legislature provided an opportunity for OCR and Chelan PUD to investigate multiple purpose facilities that could meet both the needs of OCR and the potential future needs of Chelan PUD or some other utility. In 2009, Chelan PUD and the OCR signed an Agreement in Principal that outlined how the two entities would work together to investigate the development of new water supplies with funding provided to WDOE by the state legislature through RCW 90.90. The funding and the AIP provided an opportunity to build on the 2008 HDR/DTA work by looking for additional suitable sites. The five previous sites and any newly identified sites would be investigated from both a pumped storage and water storage perspective. HDR was hired in the spring of 2010 to provide high level answers to these questions and to provide Chelan PUD and the WDOE with an economic model that would allow further analysis by either entity on existing sites or future yet to be identified sites.

Introduction

Chelan PUD hired, with funding from WDOE Office of the Columbia River (OCR), HDR to conduct reconnaissance level studies of nine multi-purpose water storage project sites. Five of the sites had been evaluated in a prior study while four of the sites were identified in this effort. The sites were located adjacent to Lake Chelan (4 sites) and adjacent to the Columbia River between Wells Dam and Rock Island Dam (5 sites). For each of these sites, the benefits and costs associated with the following were evaluated:

- Flow augmentation for agricultural and irrigation; protection and enhancement of fishery resources; and domestic uses including commercial, municipal, and industrial purposes;
- Flexibility to respond to the water needs under different climatic conditions and changes;
- The integration of wind and other renewable energy sources;
- Power production, energy demand load following, peak shaving, and grid stabilization;
- Reconnaissance level cost opinions;
- Downstream benefits to hydro owners (increasing heavy load hour flows and increasing flows during low flow months);

This information was used to build an economic model using the software @Risk© which was used to evaluate each sites economic results against the other sites. The questions the study was designed to answer were: (1) Which sites, if any, should be investigated further? (2) Can it make sense to build a multiple-benefit project that supports the capacity markets (whether they are ancillary services and/or wind integration markets), the transmission system, and in-stream and out-of-stream uses? (3) Do the combined social and economic benefits increase the viability of a project? ; and (4) Are there cost and revenue allocation methods that make both the pumped storage component and the water storage component more economically viable to the respective interested entities.

This document is intended to be a summary of the report "*Investigation of Multiple Benefit Water Storage Projects in the Mid-Columbia Reconnaissance Level Study, HDR/DTA November 2010".*

Methodology

For each site, HDR performed the following reconnaissance level study element:

Data Collection- Physical site data and project related information from public sources identified and collected, including the U.S. Geological Survey (USGS) and quadrangle mapping/topographic sources;

Site Identification, Screening, Conceptual Layout, and Preliminary Sizing- Using the data collected; various potential upper reservoir sites were identified within Chelan and Douglas counties. For each site identified, various upper reservoir configurations were considered. For each reservoir alternative, the amount of embankment fill, reservoir area volume curves, drawdown characteristics, energy storage, and installed capacities for various hours of storage were estimated.

Geologic/Seismic Screening-A high level geologic study was conducted to evaluate potential fatal flaws that could challenge the development of the propose pumped storage projects.

Environmental, Regulatory and Licensing Study-The reconnaissance level design of the proposed pumped storage projects were evaluated to identify the necessary licensing and environmental permitting process requirements, including requirements under RCW 90.90 triggered funding of the project for the OCR. An reconnaissance level analysis of potential fatal flaw environmental impacts was completed.

Conceptual Layout and Cost Evaluation Studies-Using the information collected and developed from aforementioned elements, conceptual configurations were developed for the selected sites, various features sized, and reconnaissance level capital estimates were developed using both published information and recent quotes for similar civil works and equipment. The direct costs represent a Rough Order of Magnitude estimate (-50% to +100% of estimate) .Indirect costs were allocated based on an allowance of 25% and cover preliminary engineering and studies, license and permit applications processing, detailed engineering and studies, construction and project management, and bonds and insurance.

Economic Analysis-Two phases of economic analysis were conducted. HDR conducted the first phase that included development of an economic model that utilized cost information from above mentioned elements and several sources of revenue. Revenues used in the model came from sources such as ancillary service products, wind integration charges, energy arbitrage, and a $/AF fee assessed to out-of-stream water users. For service products where a well defined market does not exist in the Pacific Northwest, as is the case for many ancillary service products, proxy markets were used such as CAISO or NYISO. Also, as a general revenue indicator break-even capacity values are computed in the economic model. The following approach was used:

- For each site, HDR utilized a Sustainable Return on Investment approach which attempts to take into account the economic, social, and environmental benefits and impacts which included, but was not limited to:
    - Peak and off-peak energy prices;
    - Wind integration;
    - Ancillary benefits; irrigation and municipal benefits;
    - Carbon markets;
    - Displacement of fossil fuels;
    - Fishery, aquatic, and ecological benefits; and
    - Social, economic, health benefits, as well as benefits to downstream hydro owners from an increase of high load hour flows and increasing flows during normal low flow times.

- A sensitivity analysis was conducted on one of the sites to assess the impacts to project economics of changes to different variables. Examples of the variables assessed include the inclusion of production tax credits and the ancillary service market used as a proxy for an as yet mature Pacific Northwest market.

- The Net Present Value (NPV), Benefit Cost Ratio (B/C), dollar per acre foot, dollar per megawatt installed capacity and other economic indicators were developed and report for each of the site under three different alternatives. The alternatives were:

    - **Alternative 1:** The facility would operate as a pumped storage facility during normal water years, with storage releases occuring only during drought years as defined in WAC 173-563-056(1)(c)1. Probabilistically this occurs approximately 3% of the time. During water releases, 2/3 of the water would be used for out-of-stream purposes and 1/3 of the water would be used for in-stream purposes. The withdrawal would likely occur during July-August.

    - **Alternative 2:** The facility would be operated as both a water storage and pumped storage facility with annual water withdrawals. Two water release schedules were evaluated: (1) 1/3 of the storage would be released from April-June for in-stream purposes and 2/3 of the

water would be released from July to August for out-of-stream purposes; and (2) all the storage would be released in July thru August with 1/3 designated for in-stream use and 2/3 designated for out-of-stream use. The usable volume of the storage reservoir will be assumed as zero. Refill of storage could start as early as September 1 in most years.

- Costs and benefits were segregated according to whether they were generation costs such as turbines, transmission facilities, etc.; and water storage costs such as reservoir.

The second phase of the economic analysis was conducted by Chelan PUD with input from OCR. The purpose of this analysis was to evaluate additional cost and revenue allocation concepts to investigate if different methodologies could be identified that could facilitate the building of a multi-purpose project. Two sites were chosen as a "proof of concept". Six allocation methodologies were analyzed for the two sites. They are:

- WDOE and a utility share the profits (defined as project NPV) 50/50.
- WDOE pays a flat fee of $5,500/acre/foot
- The difference in project NPV is analyzed between a project that is operated as a pumped storage year round and one that provides water releases. WDOE would pay the difference between the two as a fee for the water release.
- WDOE pays for 100% of water-storage capital and 50% of annual O&M; a utility pays 100% of generation capital and 50% annual O&M. Profits, defined as project NPV, apportioned to entity that creates it.
- WDOE pays for 100% of water-storage capital; a utility pays 100% of generation capital and 100% annual O&M. Revenues apportioned to entity that creates it.
- WDOE pays for 100% of water-storage capital and 50% of annual O&M; a utility pays 100% of generation capital and 50% annual O&M. Profits, defined as project NPV, are split 50/50.

Additionally, one upside sensitivity was conducted on each of the two sites that included an increase to the capacity value of 50%.

Downside sensitivities were also conducted on four of the nine sites. This analysis used a no water release schedule. This was intended to evaluate the sensitivity of overall project economics to changes in costs, captured as increases to capacity costs of installed mW, and changes to revenue, captured as capacity value in $/kw-mo (see Attachment 4) since both of these input are highly variable at reconnaissance level investigation.

Results

Site Identification, Screening, Conceptual Layout, and Preliminary Sizing-HDR considered different upper reservoir locations and estimated the following characteristics for each: embankment volumes, reservoir area-volume curves, drawdown characteristics and energy storage, installed capacities, generating discharge, and water conveyance elements. Tables 1 and 2 provide a summary of the results of this analysis.

Table 1 Pumped Storage Alternatives - Preliminary Site Characteristics

Assumed Feature (Conceptual)	Pumped Storage Alternatives																
	1A	**1B**	**1C**	**1D**	**2A**	**2B**	**2C**	**3A**	**3B**	**3C**	**4**	**5A**	**5B**	**6**	**7**	**8**	**9**
Max Upper Reservoir Elev (msl)	1,800	1,860	1,860	2,200	3,400	3,400	3,400	3,600	3,550	3,300	2,400	2,600	2,435	1,580	1,620	1,840	1,620
Min Upper Reservoir Elev (msl)	1,600	1,650	1,650	1,950	3,300	3,330	3,300	3,400	3,300	3,100	2,200	2,350	2,350	1,420	1,435	1,690	1,440
Estimated Dam Volume (CY)	11,700,000	19,900,000	15,600,000	20,600,000	7,800,000	4,400,000	12,000,000	27,000,000	35,000,000	24,300,000	22,400,000	21,606,000	4,000,000	13,030,000	19,400,000	7,960,000	22,600,000
Lower Reservoir Elev (msl)	606	606	606	606	720	720	720	1,098	1,098	1,098	1,098	1,098	1,098	707	707	1,098	710
Upper Reservoir Drawdown (ft)	200	210	210	250	100	70	100	200	250	200	200	250	85	160	185	150	180
Min Head / Max Head Ratio (>.80)	0.83	0.83	0.83	0.84	0.96	0.97	0.96	0.92	0.90	0.91	0.85	0.83	0.94	0.82	0.80	0.80	0.80
Approx. Static Head (ft) (<2650 ft)	1,094	1,149	1,149	1,469	2,630	2,645	2,630	2,402	2,327	2,102	1,202	1,377	1,295	793	821	667	820
Maximum Dam Height (ft) (<500ft)	390	420	370	430	210	150	230	480	500	450	500	380	215	440	420	460	380
Horiz. Dist. Intake-Discharge (ft)	9,000	9,000	9,000	8,000	15,000	15,000	15,000	18,500	18,000	18,500	6,000	8,000	8,000	11,900	3,700	7,900	5,500
Required Submergence Below TW (ft)	660	660	660	660	200	200	200	220	242	230	540	660	210	660	660	660	660
Est. Conductor Length (L)	11,653	11,714	11,714	10,966	19,943	19,960	19,943	23,542	22,910	23,212	8,472	10,865	10,774	14,512	5,523	9,974	7,502
Conductor Length (L) / Static Head (H)	10.65	10.19	10.19	7.46	7.58	7.55	7.58	9.80	9.85	11.04	7.05	7.89	8	18	7	15	9
L/H General Acceptance Criteria	< 12	< 12	< 12	< 12	< 12	< 12	< 12	< 12	< 12	< 12	< 12	< 12	< 12	Not Met	<12	Not Met	<12
Upper Reservoir Usable Vol (acre-ft)	30,407	39,754	28,018	26,881	19,000	14,517	49,054	15,851	19,535	23,581	71,259	78,548	20,245	102,200	79,800	53,100	75,900
Energy Storage (MWh)	29,273	40,196	28,330	34,750	43,974	33,790	113,531	33,505	40,003	43,619	75,375	95,181	23,062	71,319	57,619	31,168	54,769
Assumed Hours of Storage	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Resulting Installed Capacity (MW)	1,464	2,010	1,416	1,737	2,199	1,689	5,677	1,675	2,000	2,181	3,769	4,759	1,153	3,566	2,881	1,558	2,738
Assumed Hours of Storage	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Resulting Installed Capacity (MW)	1,220	1,675	1,180	1,448	1,832	1,408	4,730	1,396	1,667	1,817	3,141	3,966	961	2,972	2,401	1,299	2,282
Assumed Hours of Storage	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**	**30**
Resulting Installed Capacity (MW)	**976**	**1,340**	**944**	**1,158**	**1,466**	**1,126**	**3,784**	**1,117**	**1,333**	**1,454**	**2,512**	**3,173**	**769**	**2,377**	**1,921**	**1,039**	**1,826**
Assumed Hours of Storage	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Resulting Installed Capacity (MW)	732	1,005	708	869	1,099	845	2,838	838	1,000	1,090	1,884	2,380	577	1,783	1,440	779	1,369

Table 2 Pumped Storage Alternatives-Water Conveyance Charachteristics

Alternative	General Site Characteristics				Water Conveyance System - Preliminary Characteristics								Comments
	Assumed Installed Capacity (MW) [1]	Approx Static Head (H)	Est Water Conductor Length (L)	Generating Discharge (cfs)	Tunnel Diameter (ft)	Number of Headrace Tunnels	Penstock Diameter (ft)	Number of Penstocks	Draft Tube Diameter (ft)	Number of Draft Tubes	Tailrace Tunnel Diameter (ft)	Number of Tailrace Tunnels	
1A	976	1,094	11,653	12,240	29	1	12	4	17	4	23	2	
1B	1,340	1,149	11,714	16,001	34	1	14	4	20	4	26	2	
1C	944	1,149	11,714	11,272	28	1	12	4	17	4	22	2	
1D	1,158	1,469	10,966	10,815	28	1	12	4	16	4	21	2	
2A	1,466	2,630	19,943	7,648	23	1	10	4	14	4	18	2	
2B	1,125	2,645	19,960	5,836	20	1	9	4	12	4	16	2	
2C	3,784	2,630	19,943	19,740	26	2	10	10	14	10	18	5	
3A	1,117	2,402	23,542	6,380	21	1	9	4	12	4	16	2	
3B	1,333	2,327	22,910	7,859	24	1	10	4	14	4	18	2	
3C	1,454	2,102	23,212	9,490	26	1	11	4	15	4	20	2	
4	2,512	1,202	8,472	28,673	32	2	14	8	19	8	25	4	
5A	3,173	1,377	10,865	31,615	33	2	14	8	20	8	26	4	
5B	769	1,295	10,744	8,147	24	1	10	4	14	4	19	2	
6	2,377	793	14,512	41,131	27	4	16	8	22	8	30	4	
7	1,921	821	5,523	32,116	34	2	14	8	20	8	26	4	
8	1,039	667	9,974	21,370	27	2	16	4	23	4	30	2	
9	1,826	820	7,502	30,546	33	2	14	8	19	8	25	4	

Notes:
[1] Based on a 30-hour run time.

Geologic/Seismic Screening- A high level geology and seismic screening of the following elements was conducted for all nine sites:

- Regional Geology
- Site Geology
- Regional Seismicity
- Site Seismicity
- Constructability

Based on reconnaissance level study, it does not appear there are geological/seismological fatal flaws associated with the nine sites. If there is a next phase of this study, a thorough review of the technical geological and seismological literature as well as field reconnaissance of preferred sites should be conducted to evaluate geologic conditions.

Environmental, Regulatory and Licensing Study- A reconnaissance level environmental, regulatory and licensing assessment of the following elements was conducted for all nine sites:

Environmental Impact Fatal Flaw Analysis

- Endangered Species Act (ESA) listed species
- Cultural and archaeological resources

Wetlands

- Regulatory screening
- Initial Licensing Steps

Based on a limited level of study, there does not appear to be environmental, regulatory, or licensing fatal flaws associated with the nine sites. ESA, cultural, and archaeological regulations pose the most substantial hurdle to permitting should such resources exist on-site. As a result, careful attention to ESA related topics given, and cultural and archaeological records searches and subsequent field assessments should be completed if additional investigation is conducted.

Cost Opinion and Project Schedules- A summary of the estimated direct costs, (i.e. cost of materials, labor for construction, and supply and installation of permanent equipment) for each of the reservoir alternatives is provided in Table 3. These costs are level 5 engineering estimates with a range of -50% to +100%.

Indirect costs were estimated at 25 percent of the direct costs. The costs intended to be covered by this include preliminary engineering and studies, license and permit application and processing, detailed engineering and studies, construction management, and bonds, insurance, taxes, etc.

Table 3 Opinion of Probable Cost Summary

Item	Alternative 1A	Alternative 1B	Alternative 1C	Alternative 1D	Alternative 2A	Alternative 2B	Alternative 2C	Alternative 3A	Alternative 3B	Alternative 3C	Alternative 4	Alternative 5A	Alternative 5B	Alternative 6	Alternative 7	Alternative 8	Alternative 9
Approximate Installed Capacity (MW)	976	1,340	944	1,158	1,466	1,125	3,784	1,117	1,333	1,454	2,512	3,173	769	2,377	1,921	1,039	1,826
Assumed Number of Units	4	4	4	4	4	4	10	4	4	4	8	8	4	8	8	4	8
Assumed Static Head (ft)	1,094	1,149	1,149	1,469	2,630	2,645	2,630	2,402	2,327	2,102	1,202	1,377	1,295	793	821	667	820
Assumed Usable Storage Volume (acre-ft)	30,407	39,754	28,018	26,881	19,000	14,517	49,054	15,851	19,535	23,581	71,259	78,548	20,245	102,200	79,800	53,100	75,900
Energy Storage (MWH)	29,273	40,196	28,330	34,750	43,974	33,790	113,531	33,505	40,003	43,619	75,375	95,181	23,062	71,319	57,619	31,169	54,769
Hours of Storage	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Tunnel Diameter (ft)	1 @ 29 ft	1 @ 34 ft	1 @ 28 ft	1 @ 28 ft	1 @ 23 ft	1 @ 20 ft	2 @ 26 ft	1 @ 21 ft	1 @ 24 ft	1 @ 26 ft	2 @ 32 ft	2 @ 33 ft	1 @ 24 ft	4 @ 27	2 @ 34 ft	2 @ 27 ft	2 @ 33 ft
Penstock Diameter (ft)	4 @ 12 ft	4 @ 14 ft	4 @ 12 ft	4 @ 12 ft	4 @ 10 ft	4 @ 9 ft	10 @ 10 ft	4 @ 9 ft	4 @ 10 ft	4 @ 11 ft	8 @ 14 ft	8 @ 14 ft	4 @ 10 ft	8 @ 16 ft	8 @ 14 ft	4 @ 16 ft	8 @ 14 ft
Land and Land Rights	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1
Temporary Facilities & Site Prep	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000	$ 50,000,000
Upper Reservoir and Dams																	
Dam	$ 351,000,000	$ 597,000,000	$ 468,000,000	$ 618,000,000	$ 234,000,000	$ 132,000,000	$ 360,000,000	$ 810,000,000	$1,050,000,000	$ 729,000,000	$ 672,000,000	$ 648,180,000	$ 120,000,000	$ 390,900,000	$ 582,000,000	$ 238,800,000	$ 678,000,000
Stream Diversion	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000	$ 7,500,000
Spillway	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000
Civil Works																	
Power Station - Civil	$ 131,760,000	$ 144,720,000	$ 127,440,000	$ 142,430,000	$ 131,940,000	$ 101,340,000	$ 340,560,000	$ 100,530,000	$ 119,970,000	$ 130,860,000	$ 256,220,000	$ 323,650,000	$ 87,670,000	$ 299,100,000	$ 265,100,000	$ 168,320,000	$ 251,990,000
Upper Reservoir Intake	$ 7,500,000	$ 12,000,000	$ 6,900,000	$ 6,600,000	$ 4,500,000	$ 3,000,000	$ 12,600,000	$ 3,300,000	$ 4,500,000	$ 5,700,000	$ 21,000,000	$ 24,000,000	$ 5,280,000	$ 18,000,000	$ 19,800,000	$ 10,200,000	$ 18,000,000
Vertical Shaft	$ 18,050,000	$ 22,120,000	$ 18,330,000	$ 23,100,000	$ 34,720,000	$ 30,555,000	$ 81,000,000	$ 29,720,000	$ 32,000,000	$ 31,790,000	$ 44,950,000	$ 53,030,000	$ 17,800,000	$ 43,600,000	$ 29,700,000	$ 18,350,000	$ 28,420,000
Horizontal Power Tunnel	$ 49,500,000	$ 61,875,000	$ 47,850,000	$ 45,375,000	$ 136,620,000	$ 109,890,000	$ 380,160,000	$ 106,722,000	$ 127,050,000	$ 155,001,000	$ 124,740,000	$ 123,750,000	$ 34,650,000	$ 271,656,000	$ 203,280,000	$ 135,300,000	$ 142,560,000
Penstocks	$ 13,070,000	$ 17,230,000	$ 14,160,000	$ 19,540,000	$ 40,330,000	$ 38,610,000	$ 100,820,000	$ 34,850,000	$ 34,850,000	$ 29,110,000	$ 35,640,000	$ 43,430,000	$ 11,580,000	$ 52,800,000	$ 47,520,000	$ 25,870,000	$ 47,520,000
Draft Tube Tunnels & DT Gates	$ 24,950,000	$ 33,660,000	$ 25,740,000	$ 25,740,000	$ 27,720,000	$ 19,800,000	$ 69,300,000	$ 19,800,000	$ 27,720,000	$ 29,300,000	$ 63,360,000	$ 75,240,000	$ 19,800,000	$ 67,320,000	$ 67,320,000	$ 33,660,000	$ 67,320,000
Tailrace Tunnels	$ 92,000,000	$ 124,480,000	$ 86,590,000	$ 83,890,000	$ 118,270,000	$ 101,380,000	$ 295,680,000	$ 129,890,000	$ 151,540,000	$ 167,770,000	$ 142,560,000	$ 146,120,000	$ 48,110,000	$ 573,330,000	$ 145,730,000	$ 146,520,000	$ 121,440,000
Discharge Structure & Channel	$ 22,000,000	$ 22,000,000	$ 22,000,000	$ 22,000,000	$ 22,000,000	$ 22,000,000	$ 55,000,000	$ 22,000,000	$ 22,000,000	$ 22,000,000	$ 44,000,000	$ 44,000,000	$ 22,000,000	$ 44,000,000	$ 44,000,000	$ 22,000,000	$ 44,000,000
Surge Chamber	$ 59,271,000	$ 77,809,500	$ 57,801,000	$ 59,293,500	$ 107,298,000	$ 90,070,500	$ 278,088,000	$ 96,294,600	$ 111,948,000	$ 123,891,300	$ 123,375,000	$ 132,471,000	$ 39,582,000	$ 302,611,800	$ 148,065,000	$ 107,910,000	$ 122,178,000
Draft Tube / Transformer Gallery	$ 27,000,000	$ 27,000,000	$ 27,000,000	$ 27,000,000	$ 27,000,000	$ 27,000,000	$ 69,000,000	$ 27,000,000	$ 27,000,000	$ 27,000,000	$ 55,000,000	$ 55,000,000	$ 27,000,000	$ 55,000,000	$ 55,000,000	$ 27,000,000	$ 55,000,000
Access Tunnels	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000	$ 36,000,000
Underground Haul Tunnels	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000
Site Roads	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 11,100,000	$ 11,100,000	$ 11,100,000	$ 11,100,000	$ 11,100,000	$ 11,100,000	$ 11,100,000	$ 11,100,000	$ 11,100,000	$ 11,100,000
Miscellaneous civil works and structures	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000	$ 25,000,000
Power Plant Equipment	$ 494,830,000	$ 574,860,000	$ 478,610,000	$ 496,780,000	$ 628,910,000	$ 483,050,000	$1,623,340,000	$ 522,760,000	$ 571,860,000	$ 623,770,000	$1,077,650,000	$1,361,220,000	$ 389,880,000	$1,252,000,000	$1,011,410,000	$ 567,290,000	$ 961,390,000
Switchyard	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 8,400,000	$ 5,600,000	$ 5,600,000	$ 5,600,000	$ 8,400,000	$ 8,400,000	$ 5,600,000	$ 8,400,000	$ 8,400,000	$ 5,600,000	$ 8,400,000
Transmission	$ 630,000	$ 630,000	$ 630,000	$ 630,000	$ 2,520,000	$ 2,520,000	$ 2,520,000	$ 67,200,000	$ 67,200,000	$ 67,200,000	$ 67,200,000	$ 67,200,000	$ 81,800,000	$ 13,440,000	$ 13,440,000	$ 20,160,000	$ 10,080,000
Subtotal Direct Costs	$1,438,261,000	$1,862,084,500	$1,527,751,000	$1,717,078,500	$1,662,528,000	$1,307,915,500	$3,817,568,000	$2,122,266,600	$2,499,838,000	$2,294,592,300	$2,882,695,000	$3,252,291,000	$1,057,352,000	$3,538,757,800	$2,787,365,000	$1,673,580,000	$2,702,898,000
Contingency (25%)	$ 359,565,250	$ 465,521,125	$ 381,937,750	$ 429,269,625	$ 415,632,000	$ 326,978,875	$ 954,392,000	$ 530,566,650	$ 624,959,500	$ 573,648,075	$ 720,673,750	$ 813,072,750	$ 264,338,000	$ 884,689,450	$ 696,841,250	$ 418,395,000	$ 675,724,500
Indirect Costs (25%)	$ 359,565,250	$ 465,521,125	$ 381,937,750	$ 429,269,625	$ 415,632,000	$ 326,978,875	$ 954,392,000	$ 530,566,650	$ 624,959,500	$ 573,648,075	$ 720,673,750	$ 813,072,750	$ 264,338,000	$ 884,689,450	$ 696,841,250	$ 418,395,000	$ 675,724,500
Total Construction Costs (2) (3)	$2,157,391,500	$2,793,126,750	$2,291,626,500	$2,575,617,750	$2,493,792,000	$1,961,873,250	$5,726,352,000	$3,183,399,900	$3,749,757,000	$3,441,888,450	$4,324,042,500	$4,878,436,500	$1,586,028,000	$5,308,136,700	$4,181,047,500	$2,510,370,000	$4,054,347,000
Estimated Cost ($/MW)	$ 2,210,442	$ 2,084,423	$ 2,427,570	$ 2,224,195	$ 1,701,086	$ 1,743,887	$ 1,513,307	$ 2,849,955	$ 2,813,021	$ 2,367,186	$ 1,721,354	$ 1,537,484	$ 2,062,455	$ 2,233,124	$ 2,176,495	$ 2,416,141	$ 2,220,343
Estimated Cost / New Annual Gen ($/ MWh)	$ 1,009	$ 952	$ 1,108	$ 1,016	$ 777	$ 796	$ 691	$ 1,301	$ 1,284	$ 1,081	$ 786	$ 702	$ 942	$ 1,020	$ 994	$ 1,103	$ 1,014

1. Costs to be estimated by Chelan PUD.
2. Cost estimates are AACE Class 5 estimates with 25 percent contingency.
3. Cost estimates are in 2010 US dollars and exclude cost for pumping, life cycle operations and maintenance, lost revenue due to any plant outage, time cost of money, and escalation for labor/material.

Annual O&M for the nine sites range from $10 million to $23 million. Additionally general and administration costs are estimated to range from $3.5 million to $8 million annually. Major maintenance was estimated to cost $10 million per unit for a major unit overhaul at year 20 of operation.

The project schedule will be dependent on many factors such as site conditions, technology, and regulatory environment. However a 10-year development schedule appears to be reasonable at this level of project development.

Economic Analysis

Phase 1

Economic indicators were evaluated in two ways for each site. First the economics of each site were assessed by looking at the combined costs for both water storage and pump storage operations and revenues for pump storage. Second, the economics for each site were evaluated by dividing the costs and benefits between water storage and pumped storage components. This was done for two reasons; first OCR is interested in identifying the cost of the storage components with a $/acre-foot (AF) metric so they can compare to other options they are investigating. Second, Chelan PUD and OCR are interested in understanding how the economics of a site could change for entities interested in either the water storage or pumped storage components. If the economics from the pump storage component was enhanced, then additional options may be available.

The total quantified benefits of the projects may range from $1.1 billion to $3.7 billion with total costs ranging from $1.2 billion to $3.9 billion. Under current assumptions and evaluating the sites from a combined cost and benefit perspective, the BC ratios ranged from 0.65 to 1.24, with four of the nine sites having BC ratios greater than 1 (See Attachment 1). When the costs were divided between pumped storage and water storage components, the BC ratios for pumped storage only ranged from 1.44 to 2.64 while the BC ratios for water storage only ranged from 0.02 to 0.07. The cost per AF of water ranged from $21,000/AF, to $70,000/AF. The NPV for the sites evaluated with costs and benefits combined ranged from -$1100 million to $750 million over 50 years. When the components were divided, the NPV for pumped storage facilities located at the sites ranged from approximately $200 million to $2,200 million while the NPV of water storage ranged from -$500 million to -2,200 million.

Approximately 7 percent of the benefits from the plant come from arbitrage opportunities while 92 percent comes from ancillary services. Since so much of a projects value is derived from selling products into the ancillary service markets, it's important to note these markets are immature in the Pacific Northwest so the benefits associated with these markets are highly uncertain at this time. A small percentage of revenue would also come from the sale of water-rights on a per AF basis. The choice of ancillary services market used for pricing was the variable results were most sensitive to. Other major sensitivities included the decision to include or not include a production tax credit or an investment tax credit, the water release alternative used, the hours of generation, and the plant efficiency. Site 4 was used to show how these major sensitivities can impact the value of the project; the results are reported in Table 4. Interestingly, in many of the scenarios, the social and environmental costs and benefits were very small and did not appreciably add to or take away from site viability.

Table 4 Major Sensitivities Using Site 4 as Example

Variable	Worst Cased Value	Best Case Value	Worst Case Median NPV ($M)	Best Case Median NPV ($M)
Choice of Ancillary Service Market	CAISO	NYISO for Regulation/ERCOT for Reserves	$729	$3,688
Production Tax Credit Rate	No	Yes 1.1C/kWh	$653	$729
Investment Tax Credit Rate	No	Yes 30%	$729	$1,695
Water Release Alternative	2a	1	$-298	$729
Hours of Generation	6	10	$729	$1,790
Plant Efficiency	75%	80%	$729	$770

Phase 2

Two sites (5B and 4) were selected to show how different cost and benefit allocation concepts could influence the economic viability of a project from both the water storage and pump storage perspective. The sites were also evaluated using different release scenarios. Site 5B was analyzed using an annual release during July and August. Site 4 was analyzed with water releases only occurring during drought years. This is intended to show a range of possible outcomes.

The results (See Attachment 2 and 3) do not include any economics evaluating the potential benefits of the use of that water. The scenarios show two metrics from a OCR perspective: a) NPV of the cash outflows for the noted cost allocations to water storage and b) The related NPV applied to the installed reservoir capacity, a $ / AF (acre foot) metric. For site 5B, the various allocations of cash flows to OCR yield's NPV of costs ranging from -$111 million to -$572 million, with corresponding installed capacity costs of $5,500/AF to $28,232/AF. For site 4, the various allocations of cash flows to OCR yield's NPV of costs ranging from 132 million to -$1,642 million, with corresponding installed capacity costs of -$1,850/AF to $23,039/AF. The plus position of the NPV indicates that OCR could take in revenue in excess of costs.

Additional sensitivities were also conducted using sites 5B and site 4 to identify how changes in costs and benefits would affect the overall economics of a project. The NPV of the base case for site 5B was -$83 million. This was reduced to -$458 million with an increase in the installed capacity cost going from $1.44 million/mW to $2.0 million/mW. Reducing the revenues received estimate from $9.24 / kW-month base down to $1.29 / kW-month , which is the current BPA wind integration charge rate, dropped the NPV to -$886 million. The NPV of the base case for site 4 was $283 million. This was reduced to -$1,381 million with an increase in the installed capacity cost going from $1.44 million/mW to $2.0 million/mW. Reducing the revenues received estimate from $9.24 / kW-month base down to $1.29 / kW-month, which is the current BPA wind integration charge rate, dropped the NPV to -$2,324 million.

Caveat

From the reconnaissance level study: "The economic analysis is a high-level screening of the proposed sites. The purpose is concept screening to identify sites with the most potential for further study. As is emphasized later in this report, costs and benefits are at this level of project definition highly uncertain."

Cost estimates range from an accuracy of ~-50% to +100%. An example of this is projected cost of $100 could range from $50 to$200. "As important to note in this analysis is that the revenues are as, if not more uncertain. Wind integration charges are just starting to be developed and established liquid ancillary services markets are not yet available in this region."[2]

Conclusion

The results of the study indicate that there may be an opportunity for a combined pumped storage and water storage facility to provide positive economic benefits. Specifically site 2A (on the Columbia River) and 4 and 5B (on Lake Chelan) may warrant further investigation since these three sites had positive economic results from a combined perspective. Additionally, OCR may want to further investigate sites 6 and 9 since these sites may have lower costs per AF, have BC ratios close to 1.0, and provide relatively large amounts of water storage. Although the initial cost of a pump storage facility is high when compared to other current technologies that are used to integrate wind and other intermittent renewable generation sources, a pump storage facility is able to produce additional grid friendly ancillary services that could increase the economic value of the facility.

There may also be value from a regional perspective for a facility that can back up renewable generation with an emission free source. The economics of a project may change for the positive if the project can receive increased capacity value from Renewable Energy Credits by being identified as a renewable generation source in state or federal renewable portfolio standards. Both sites 4 and 5B showed an increase in the economic metrics when additional capacity values were evaluated.

The Phase 2 analysis indicates that running a pump storage facility for water storage benefits may enhance the overall economics of the project to participants. This is highly dependent on the operational requirements added to the facility to meet the water storage needs, balanced with how much of a cost burden the water storage component is able to bear. Additionally, if a facility qualifies under RPS statutes, additional value may be obtained. The overall economics of a project are also highly dependent on the prices that can be obtained for products that a pump storage facility can provide including ancillary services and wind integration. The potential revenue stream for a pumped storage facility located in the Pacific Northwest is highly uncertain. Sensitivities using current BPA prices in the Pacific Northwest would not support the development of a pump storage facility. However, given the immaturity of the markets, future prices are difficult to forecast. The manner in which these markets evolve will need to be closely watched as decisions to move from one project phase to the next are considered. Some market maturity may be on the horizon since the development of ancillary services and associated markets has been identified as a primary tactic to address wind integration challenges[3].

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[2] 2010. HDR/DTA. Investigation of Multiple Benefit Water Storage Project in the Mid-Columbia.
[3] The Oregonian. Wednesday January 26. Questions and Answers by Jon Wellinghoff.
http://www.oregonlive.com/business/index.ssf/2011/01/ferc_commissioner_jon_wellingh.html

Attachment 1 Phase 1 Economic Analyses Electrical Products and Water Storage Results

Site 1B

39,754 acre-feet

	Combined				Water Storage				Pump Storage		
Alternative	Cost ($M)	NPV ($M)	BC	IRR (%)	Cost($M)	$/AF	NPV ($M)	BC	Cost($M)	NPV ($M)	BC
1	$2,083	$22	1.01	4.47	$1,328	$33,414	-$1,265	.05	$755	$1,174	2.58
2a	$2,117	-$533	.75	3.24	$1,328	$33,414	-$1,219	.05	$788	$610	1.78
2b	$2,101	-$233	.89	3.85	$1,328	$33,414	-$1,219	.05	$773	$890	2.17

Site 2A

19,000 acre-feet

	Combined				Water Storage				Pump Storage		
Alternative	Cost ($M)	NPV ($M)	BC	IRR (%)	Cost($M)	$/AF	NPV ($M)	BC	Cost($M)	NPV ($M)	BC
1	$1,871	$394	1.21	5.40	$1,078	$56,718	-$1,047	.03	$793	$1,316	2.68
2a	$1,906	-$239	.87	3.76	$1,078	$56,718	-$1,025	.03	$829	$701	1.85
2b	$1,890	$88	1.05	4.65	$1,078	$56,718	-$1,025	.03	$813	$1,007	2.26

Site 3C

23,581 acre-feet

	Combined				Water Storage				Pump Storage		
Alternative	Cost ($M)	NPV ($M)	BC	IRR (%)	Cost($M)	$/AF	NPV ($M)	BC	Cost($M)	NPV ($M)	BC
1	$2,528	-$276	.89	4.47	$1,655	$70,198	-$1,618	.02	$872	$1,219	2.42
2a	$2,563	-$899	.65	3.24	$1,655	$70,198	-$1,591	.02	$908	$609	1.68
2b	$2,547	-$574	.77	3.85	$1,655	$70,198	-$1,591	.02	$892	$913	2.04

Site 4

71,259 acre-feet

	Combined				Water Storage				Pump Storage		
Alternative	Cost ($M)	NPV ($M)	BC	IRR (%)	Cost($M)	$/AF	NPV ($M)	BC	Cost($M)	NPV ($M)	BC
1	$3,190	$758	1.24	5.54	$1,823	$25,581	-$1,710	.06	$1,367	$2,254	2.67
2a	$3,240	-2763	.91	3.97	$1,823	$25,581	-$1,627	.06	$1,418	$1,205	1.86
2b	$3,217	$282	1.09	4.87	$1,823	$25,581	-$1,627	.06	$1,394	$1,27	2.25

Site 5B

20,245 acre-feet

	Combined				Water Storage				Pump Storage		
Alternative	Cost ($M)	NPV ($M)	BC	IRR (%)	Cost($M)	$/AF	NPV ($M)	BC	Cost($M)	NPV ($M)	BC
1	$1,156	$45	1.04	4.61	$620	$30,626	-$588	.05	$536	$569	2.09
2a	$1,180	-$279	.76	3.28	$620	$30,626	-$564	.05	$560	$242	1.44
2b	$1,169	-$106	.91	3.94	$620	$30,626	-$564	.05	$549	$405	2.76

Site 6

102,200 acre-feet

	Combined				Water Storage				Pump Storage		
Alternative	Cost($M)	NPV ($M)	BC	IRR (%)	Cost($M)	$/AF	NPV ($M)	BC	Cost($M)	NPV ($M)	BC
1	$3,914	-$124	.97	4.25	$2,366	$23,154	-$2,204	.07	$1,547	$1,878	2.23
2a	$3,963	-$1,061	.73	3.17	$2,366	$23,154	-$2,086	.07	$1,596	$884	1.56
2b	$3,941	-$534	.86	3.71	$2,366	$23,154	-$2,086	.07	$1,574	$1,378	1.89

Site 7

79,800 acre-feet

	Combined				Water Storage				Pump Storage		
Alternative	Cost ($M)	NPV ($M)	BC	IRR (%)	Cost($M)	$/AF	NPV ($M)	BC	Cost($M)	NPV ($M)	BC
1	$3,092	-$35	.99	4.35	$1,837	$23,021	-$1,710	.07	$1,255	$1,511	2.22
2a	$3,135	-$798	.75	3.21	$1,837	$23,021	-$1,618	.07	$1,298	$707	1.55
2b	$3,115	-$372	.88	3.80	$1,837	$23,021	-$1,618	.07	$1,278	$1,108	1.88

Site 8

53,100 acre-feet

	Combined				Water Storage				Pump Storage		
Alternative	Cost ($M)	NPV ($M)	BC	IRR (%)	Cost($M)	$/AF	NPV ($M)	BC	Cost($M)	NPV ($M)	BC
1	$1,863	-$197	.89	3.86	$1,129	$21,270	-$1,045	.07	$734	$761	2.06
2a	$1,892	-$602	.68	3.06	$1,129	$21,270	-$984	.07	$762	$322	1.43
2b	$1,879	-$369	.80	3.42	$1,129	$21,270	-$984	.07	$749	$540	1.74

Site 9

75,900 acre-feet

	Combined				Water Storage				Pump Storage		
Alternative	Cost ($M)	NPV ($M)	BC	IRR (%)	Cost($M)	$/AF	NPV ($M)	BC	Cost($M)	NPV ($M)	BC
1	$2,999	-$94	.97	4.25	$1,801	$23,733	-$1,681	.07	$1,198	$1,431	2.21
2a	$3,040	-$819	.73	3.17	$1,801	$23,733	-$1,593	.07	$1,239	$667	1.54
2b	$3,022	-$414	.86	3.71	$1,801	$23,733	-$1,593	.07	$1,220	$1,048	1.87

Notes

-All figures include externalities, and are based on discounted output values

-All monetary values expressed in millions of dollars, real

-All cost values include all direct and indirect costs (capital, O&M, indirect, and societal costs)

Comparison of Water Storage Costs Associated with Foster Creek Conservation District Water Storage Study

Combined Costs				Water Storage Costs		Pumped Storage Costs
Site	Cost ($M)	Volume Of Water (AF)	$/AF	Cost($M)	$/AF	Cost($M)
Lower Rock Island Creek	864	85,300	10,100	$474	$5,600	390
Upper Rock Island Creek	$1,168	65,900	17,700	$271	$4,100	897
Foster Coulee	$705	69,700	10,100	$78	$1,100	627

Attachment 2 Phase 2 Economic Analyses on Different Benefit/Cost Allocation Methodologies Site 5B

Site Information	
All dollars are $M real	
Site	5B
Water Release Alternative	2b-Annual release in July and August
Reservoir Capacity (AF)	20,245
Capacity (mW)	769
Upfront 1-off costs	1,110
Capacity Value $/kW-mo	8.77
Time Period	50 Years
Capacity Cost/mW installed	1.47

Scenario Description	% WDOE OCR pays storage upfront costs	% WDOE OCR pays annual O&M	% share of profit (NPV)WDOE OCR Receives	Combined NPV	Combined IRR nominal	Utility NPV	WDOE OCR NPV	WDOE OCR $/AF installed
WDOE OCR pays $5,500/acre foot	22%	0%	0%	(241)	5.97%	**(129)**	(111)	5,500
WDOE OCR and utility share the profits (defined as project NPV) 50/50	0%	0%	50%	(241)	5.97%	(120)	(120)	5,945
WDOE OCR pays the difference in NPV between a facility operated for pumped storage only and a facility that releases water for downstream uses	31%	0%	0%	(241)	5.97%	(83)	(158)	7,790
WDOE OCR pays 100% water storage capital, 50% annual O&M, recieves 50% of pumped storage product profits	100%	50%	50%	(241)	5.97%	165	(406)	20,061
WDOE OCR pays 100% water storage capital, 0% annual O&M	100%	0%	0%	(241)	5.97%	270	(511)	25,234
WDOE OCR pays 100% water storage capital, 50% annual O&M	100%	50%	0%	(241)	5.97%	331	(572)	28,232
Upside Sensitivity-Capacity Value $14.09/kW-mo								
WDOE OCR pays 100% water storage capital, 50% annual O&M, recieves 50% of pumped storage product profits with 50% greater capacity value from REC.	100%	50%	50%	170	7.6%	370	(200)	9,893

***There is no revenue from a water storage fee included in the above results**

Attachment 3 Phase 2 Economic Analysis on Different Benefit Cost Allocation Methodologies Site 4

Site Information	
All dollars are $M real	
Site	4
Water Release Alternative	1-Drought release in July and August
Reservoir Capacity (AF)	71,259
Capacity (mW)	2,512
Upfront 1-off costs	3,209
Capacity Value $/kW-mo	9.24
Time Period	50 Years
Capacity Cost/mW installed	1.28

Scenario Description	% WDOE OCR pays storage upfront costs	% WDOE OCR pays annual O&M	% share of profit (NPV)WDOE OCR Receives	Combined NPV	Combined IRR nominal	Utility NPV	WDOE OCR NPV	WDOE OCR $/AF installed
WDOE OCR and utility share the profits (defined as project NPV) 50/50	0%	0%	50%	264	7.33%	**132**	132	(1,850)
WDOE OCR pays the difference in NPV between a facility operated for pumped storage only and a facility that releases water for downstream uses	1%	0%	0%	264	7.33%	**283**	(20)	274
WDOE OCR pays $5,500/acre foot	26%	0%	0%	264	7.33%	656	(392)	5,500
WDOE OCR pays 100% water storage capital, 50% annual O&M, recieves 50% of pumped storage product profits	100%	50%	50%	264	7.33%	953	(689)	9,670
WDOE OCR pays 100% water storage capital, 0% annual O&M	100%	0%	0%	264	7.33%	1,787	(1,523)	21,374
WDOE OCR pays 100% water storage capital, 50% annual O&M	100%	50%	0%	264	7.33%	1,905	(1,642)	23,039
Upside Sensitivity-Capacity Value $14.04/kW-mo								
WDOE OCR pays 100% water storage capital, 50% annual O&M, recieves 50% of pumped storage product profits with 50% greater capacity value from REC.	100%	50%	50%	1,858	9.12%	1746	112	(1,568)

***There is no revenue from a water storage fee included in the above results**

Attachment 4 Downside Sensitivity to Cost and Revenue of Four Sites

$ M Real
No Water Release

Scenario Description	Site	Reservoir Capacity (AF)	Capacity (MW)	Upfront 1-off costs	Capacity Cost/mW	Capacity Value $/kW-mo	NPV	IRR
Base	5B	20,245	769	1,129	1.47	9.24	(83)	6.50%
Increase Cost	5B	20,245	769	1,538	2.00	9.24	(458)	5.49%
Decrease Revenue	5B	20,245	769	1,129	1.47	1.29	(866)	NA
Base	4	71,259	2,512	3,209	1.28	9.24	283	7.35%
Increase Cost	4	71,259	2,512	5,024	2.0	9.24	(1,381)	5.62%
Decrease Revenue	4	71,259	2,512	3,209	1.28	1.29	(2,324)	1.64%
Base	2A	19,000	1,466	1,877	1.28	9.24	160	7.34%
Increase Cost	2A	19,000	1,466	2,932	2.00	9.24	(808)	5.62%
Decrease Revenue	2A	19,000	1,466	1,877	1.28	1.29	(1,366)	NA
Base	6	102,200	2,377	3,989	1.68	9.24	(591)	6.30%
Increase Cost	6	102,000	2,377	4,754	2.00	9.24	(1,292)	5.64%
Decrease Revenue	6	102,000	2,377	3,989	1.68	1.29	(3,059)	NA