RESTRICTED DISTRIBUTION REPORT

EVALUATION

OF THE

BLACK ROCK PROJECT's

PUMPED STORAGE

POWER COSTS AND BENEFITS

Created by

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Black Rock Water Storage Project -- Power Benefits Review

Introduction

The U.S. Bureau of Reclamation (the Bureau) together with numerous Washington State government officials and Yakima Valley irrigation interested parties has been studying the proposed Black Rock Reservoir project for many years. The idea of taking excess Columbia River water and conveying it to the Yakima Valley has been around since 1973 when the valley experienced an extreme drought. The listing of endangered salmon in the late 1990's further restricted natural water supplies to instream use to preserve salmon habitat. In extreme low water years, the Yakima River can't supply all of its current obligations, and junior water right holders are the first to be cut off.

An average water supply year in the Yakima River Basin is between 2.25 and 3.25 million acre-feet. Currently, the total Yakima River basin's average year water rights total about 870,000 acre-feet of irrigation demand. In dry years, the Basin's firm water rights drop to about 552,000 acre-feet. The Black Rock Project as envisioned would firm up interruptible water rights and leave freed up Yakima River water not diverted by irrigation participants for instream flow and future municipal supply needs.

This power requirements and benefits "Review" will be based on the Bureau's December 2004 "Summary Report Appraisal Assessment of the Black Rock Alternative" hereafter referred to as the "Report". This Bureau Report (Technical Series No. TS-YSS-7) is part of the "Yakima River Basin Water Storage Feasibility Study" conducted jointly by the State of Washington and the Bureau. The Report assumed a large reservoir of 1.3 million acre-feet of active storage at an elevation of 1,775 feet. The source of the water would be from the Columbia River at Grant PUD's Priest Rapids Dam reservoir. The pumping required to raise the water from 488 feet at the Priest Rapids Reservoir's full elevation to the Black Rock's Reservoir's 1,775 feet at full elevation would require an annual average of 172 Megawatt's (MW's). The size of the Project's pumping capacity is assumed to be approximately 500 MW's based on the Report's Table 5-5.

The Pump/Generation Alternative:

The Report looked at one alternative configuration of the Black Rock Project where power generators would be added along side the pumps at the Columbia River water intake facilities in the Priest Rapids Dam reservoir. This would convert the Black Rock from simply an irrigation water transfer project into a Pumped Storage hydroelectric project.

As some background information, the following diagrams and discussion are taken from the American Society of Civil Engineers' (ASCE) "Civil Engineering Guidelines for Planning and Designing Hydroelectric Developments – Volume 5 – Pumped Storage and Tidal Power", published in 1989, pages 1-1 and 1-2:

"Figure 1-1a (on the next page) shows that pumped storage plants exhibit the same characteristic features as a conventional hydroelectric plant, but the difference lies in the operation of the plant. Figure 1-1b illustrates the plant's operation in the power system. Water is pumped from a lower reservoir to a higher reservoir when low-cost pumping energy is available … It is released during periods of high power demand and displaces the use of inefficient, costly alternative sources of generation. The difference between the power values can be very large and, as a result, the process can show a profit."

The ASCE Guidelines go on to say on page 1-3: "In addition to the classic operation just described, pumped storage plants show a beneficial influence on the operation of other plants in the power and transmission system. The demand is highly variable and changes rapidly. Response to demand must also be rapid. Properly designed pumped storage plants are ideal for this operation. They can benefit the system operation by:

a. Taking over the steep upward and downward slopes of the network load diagram at the beginning and at the end of the daily working period.
b. Regulating frequency to meet sudden load changes in the network.
c. Serving as emergency power reserve.
d. Meeting weekly and seasonal peak power demands (as do some pumped storage schemes in Switzerland and Austria).
e. Improving the power factor of the network.
f. Improving the quality of alternative energy sources such as wind, small hydro, solar and tidal power that exhibit an intermittent supply characteristic."

The Columbia River Intake Pump/Generation (P/G) facilities analyzed in the Report came up short from an economic standpoint. The Report concluded that incremental cost of $190 Million to add P/G at the Project isn't feasible based on estimated benefits of **capacity service** using the Report's estimated Mid-Columbia power rates from Oct. 2004 through September 2006. (See page 134 of the Report).

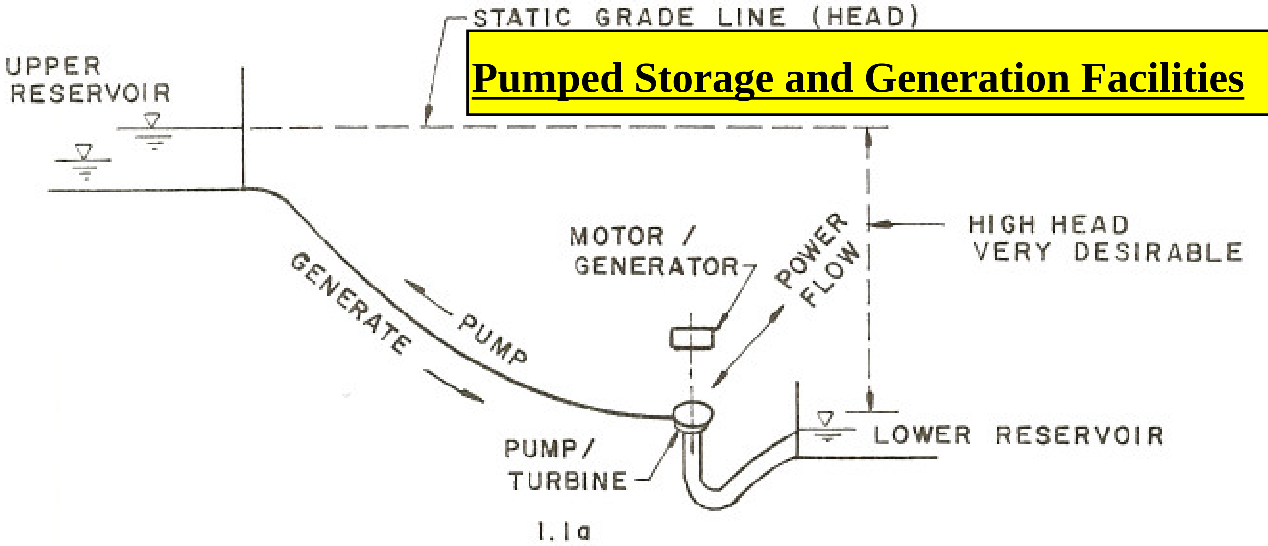
BPA defines **capacity service as:**

> The service whereby one utility delivers firm energy during a second utility's period of peak usage with return made during the second utility's offpeak periods; compensation for this service may be return energy or money.

The Report's estimated average daily peak usage or Heavy Load Hour (HLH) rate was 19.7% higher than the corresponding offpeak or Light Load Hour (LLH) rate. (HLH's run from hour ending 7 AM to 10 PM, Monday through Saturday; LLH's are from 11 PM through 6 AM and all day Sunday). In other words, the daily average value of capacity service provided roughly a 20% premium. The report says: "Therefore, to breakeven simply on an opportunity cost basis (for value of daily capacity service), there would need to be a heavy-load hour price premium of 28% over light-load hour prices." Later in on page 135 of the Report, it said" "… at this time, because the above returns are either negative or zero … pumped generation appears financially not viable."

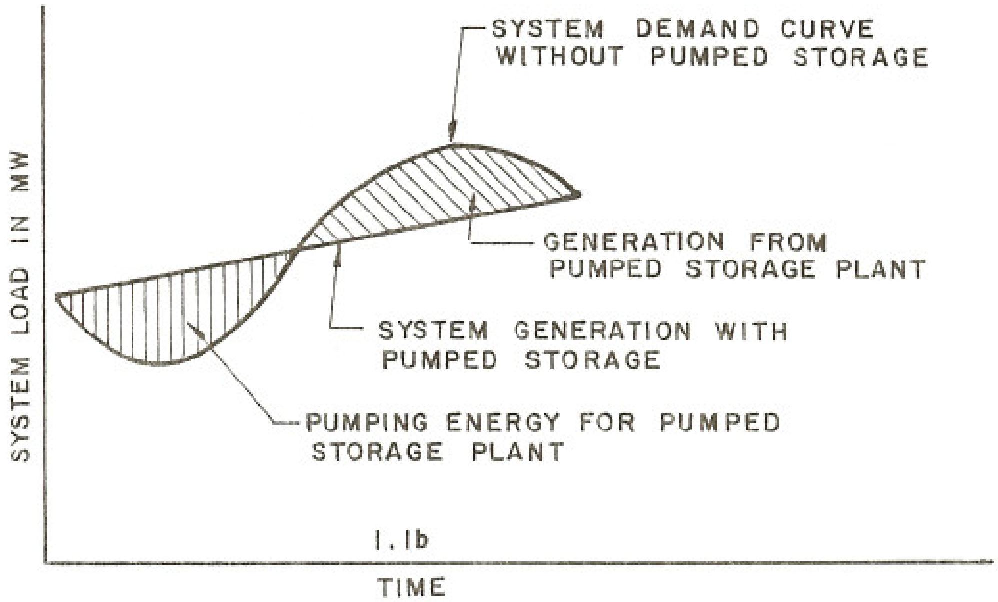
The report acknowledged with regard to possible wind integration opportunities: "It is possible, however, if pump/generation were developed with dynamic capability that was available at all times, there may be opportunities to partner with the Northwest's growing wind industry which has a great need for dynamic shaping services."

Pumped Storage and Generation Facilities



PUMP STORAGE PLANT SCHEMATIC

Example of levelizing system generation by pumping at night when power prices are "cheap" and then generating during the day time when power prices are more expensive. The net benefit of this practice is called "Capacity Service" which can offset the pump-generation cycle losses.



LOAD DEMAND CURVE

Figure 1–1. — Premise of pumped storage. [Logan, 1982 and 1984].

Some useful approximations:

- Pumping energy = 130% generating energy
- Stored energy = $\gamma \times$ volume $\times$ head $\times$ efficiency
- IAF of water dropping 1,000 ft = 900 kWh at 88% efficiency

Taking these pumped/generation parameters one at a time, this Black Rock Project power benefits review will show that P/G facilities deserve a second look to potentially reduce the power costs of the project.

Incremental Cost of Pump/Generation Facilities:

As stated above, the Report estimated the incremental cost of adding pumped/generation at Black Rock Project at $190 Million over the cost of just pumping facilities to fill the Black Rock Reservoir. One design assumption that needs further investigation is why there is separate pumping and generation facilities? Quoting the Nov. 15, 2001 “Black Rock Reservoir Study” by Washington Infrastructure Services, Inc. (W.I.S. 2001 Study), Section 6.12.2 “All pumped storage plants in the United States use single-stage reversible pump/turbines. This type of installation features a single stage reversible pump/turbine on a common shaft with a motor/generator.” There must have been an underlying assumption in the Report that lead to separate pumping and generation facilities, which greatly raised the cost of pumped storage. If the Black Rock Project’s proposed pumped storage facilities could use of single-stage P/G facilities, then the incremental costs of P/G should be greatly reduced.

Capacity Service Premium:
The 20% premium of capacity service to capture the HLH peak period’s value over LLH offpeak periods has been growing in the last three years. This trend will encourage pumped storage projects such as Black Rock to include generation potential. Power prices have risen over the last three years and so has the capacity service premium. The following table also shows the actual average power prices over the last three years at the Mid-Columbia Power Trading Hub.

Mid-Columbia Average Power Prices (Oct thru Sep)

$/MWh	HLH - Heavy Load Hour	LLH - Light Load Hour	Average	Difference =“Capacity Service” Value	**Difference in “Value” Percent**
FY 2004	$42.01	$36.29	$40.10	$5.72	**15.8%**
FY 2005	$52.40	$42.55	$49.12	$9.86	**23.2%**
FY 2006	$57.57	$45.00	$53.38	$12.57	**27.9%**

This trend is assumed to be in part because of further restrictions in the operation of the Federal Columbia River Power System (FCRPS) due to fish constraints. During certain times of the year (e.g. May and June) the River is run at fairly high flows to flush fish to the sea when there is a corresponding small demand for power in the market. Since hydroelectric project operators are not able to back off night time generation in these circumstances, then the market premium for capacity service goes up substantially. This happens at other times of the year as well when capacity is limited and unable to keep up with peak demands.

Pumped/Generation Cycle Loss Factor: The 28% quoted is a typical loss factor in a pumped storage project in a pump/generation cycle. The Report says that this hurdle doesn’t include assumptions about potential head losses (mainly in the 6.4 mile tunnel to Black Rock from the Columbia River) that would raise the HLH/LLH premium. An earlier study says that this premium would need to be 41% with estimated head losses included to "breakeven". (See Section 7.2.1 of the W.I.S. 2001 Study).

The following table shows that P/G can provide a capacity service benefit of about $5.6 million per year if the P/G cycle losses can be reduced to 20%. The table also shows that as the P/G cycle losses go up, the value of capacity service from the Project's P/G facilities goes down.

Value of Pumped/Generation (P/G) Capacity Service
(Assume year w/o BR pumping) **Assumed Generation of 400 MW**

P/G Cycle Losses>	Fiscal Year (Oct-Sep)	Days with HLH/LLH Premium Value Greater than P/G Cycle Losses	%Days/yr	Capacity Value	
20%	**Optimal**				
	FY05	148	40.5%	$ 3,910,881	
	FY06	165	45.2%	$ 7,331,256	
	Two Year Avg=	156.5	42.9%	**$ 5,621,069**	
Losses> 25%	FY05	106	29.0%	$ 2,683,391	Percent of
	FY06	140	38.4%	$ 6,301,966	Optimal
			Two Year Avg=	$ 4,492,678	79.9%
Losses> 30%	FY05	81	22.2%	$ 2,416,596	Percent of
	FY06	117	32.1%	$ 5,594,998	Optimal
			Two Year Avg=	$ 4,005,797	71.3%

(Later in this Review, the estimated Capacity Service annual benefit was reduced to $2.1 million per year for 20% the P/G efficiency scenario to take into account the Project's pumping requirements and potential conflicts with wind integration capacity requirements).

Potential Project Re-Configurations to Optimize Pumped Storage Power Benefits:

It is possible to reduce the loss cycle to 20% if the Project were designed from the beginning to optimize the Project's P/G potential. With 20% P/G cycle losses, then the Project's 500 MW pumping facilities could produce 400 MW's of generation with single stage reversible P/G units. Also with greater P/G efficiency, the amount of water pumped can increase as the losses decrease. This Review assumed a 4,000 cubic feet per second (cfs) configuration per the W.I.S 2001 Study.

One way to reduce the P/G loss cycle is to have a relatively high head upper reservoir close to the lower reservoir. As an example, the Grand Coulee – Banks Lake P/G, 55 MW units achieve an energy cycle loss of only 20% with a head of about 300 feet and flow of 2,000 cubic feet per second (cfs). This is possible because of the relatively high head versus horizontal distance between the upper reservoir and the lower one. (Personal communication with Steve Sauer, Electrical Engineer with Grand Coulee Power Office of the Bureau of Reclamation, 10-23-06).

Quoting from the 1989 "Civil Engineering Guidelines for Planning and Designing Hydroelectric Developments – Volume 5 Pumped Storage …" Section 3.21:

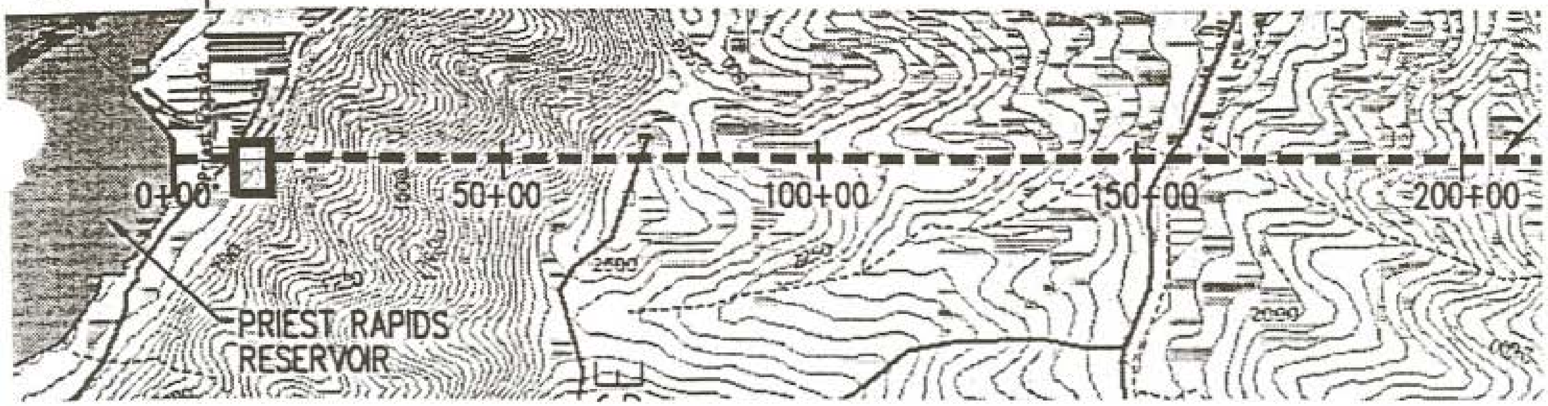
> "L/H Ratio: One of the most important parameters in the assessment of a pumped storage site is its ratio of the total length of the water conduits (L) to the head at the site (H).
>
> This is especially important if a surface type powerhouse is to be included in the design. A surface powerhouse with relatively long tunnels in comparison to its head will not be able to provide some of the dynamic benefits of pumped storage because its response time will be too slow. An underground powerhouse with a surge tank can allow the development of these types of sites with very good system response.
>
> Recent experience suggests the maximum acceptable L/H ratios range from 10 to 12 for high-head (1,200 to 1,500 ft) projects …."

The Grand Coulee P/G units have a horizontal length (L) divided by the Head (H) difference between the upper and lower reservoir of less than 3.5. In the case of the proposed Project, the length is 6.4 miles or about 34,000 feet. Since the design head for the 1.3 million ac-ft storage project is roughly 1,300 feet, the L/H ratio is about 26. This very high L/H effectively kills the feasibility of P/G units providing power benefits of pumped storage generation because of P/G cycle losses over 40%. If this L/H ratio could be reduced somehow closer to Grand Coulee's 3.5 L/H ratio then the P/G loss cycle could be reduced as well.

On the next page (take from W.I.S. 2001 Study, Figure 6.5-7) are profiles of two Project re-configuration options that could accomplish this goal. Following that is a map of the area with some of the Options' features, and then a picture of Grant PUD's Priest Rapids Dam and the Umtanum Ridge behind it looking South towards the Black Rock Project's location 6.5 miles away.

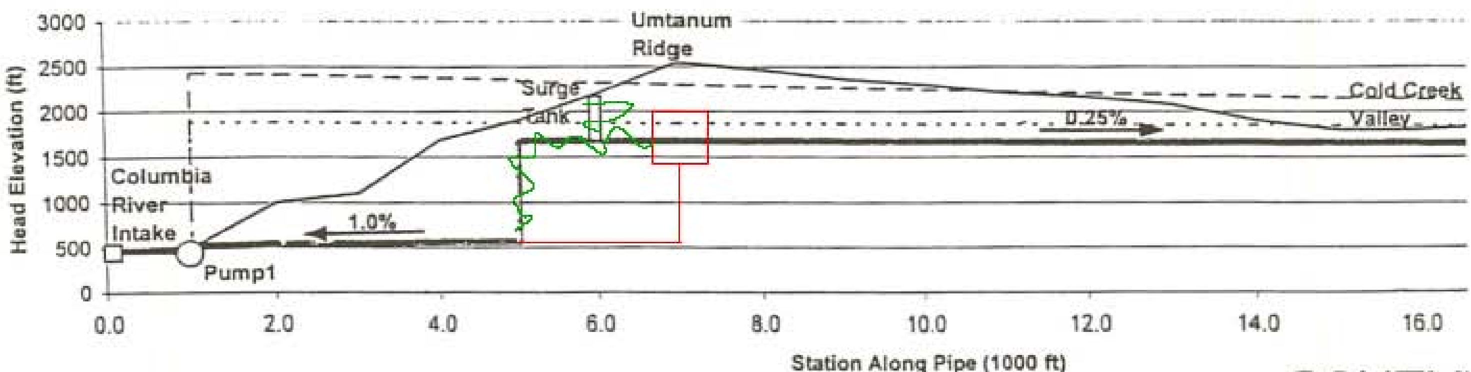
Option A would create a large underground reservoir at about the 1,800 foot elevation level and approximately the size of a cube with 700 foot sides with an L/H factor of 5.3 and an assumed loss cycle factor of 20%. This amount of underground storage would accept the assumed 500 MW's of pumping from the Priest Rapids Reservoir on the Columbia River over a 24 hour Sunday period for capacity service purposes. A smaller underground reservoir may be more practical to store eight hours of Light Load Hour pumping, but this limits the P/G facilities' ability to earn capacity service revenues.

Option B would develop an upper Reservoir #1 on the nearby Umtanum Ridge at 2,500 feet in elevation. (See map after the next page showing Option B's Reservoir #1 in relation to the Columbia River. An additional Reservoir #2 is shown on this map in the Cold Creek Valley could serve as another P/G source reservoir not connected directly to the Columbia River). It is much easier from an engineering standpoint to construct the surface reservoir in Option B than an underground one in Option A. Option B would have roughly the same L/H factor of 3.5 as the Grand Coulee P/G units with an assumed loss cycle factor of 20%. The additional power benefits of Option B could reduce the net pumping costs of the Black Rock Project further, especially with additional wind integration revenue.



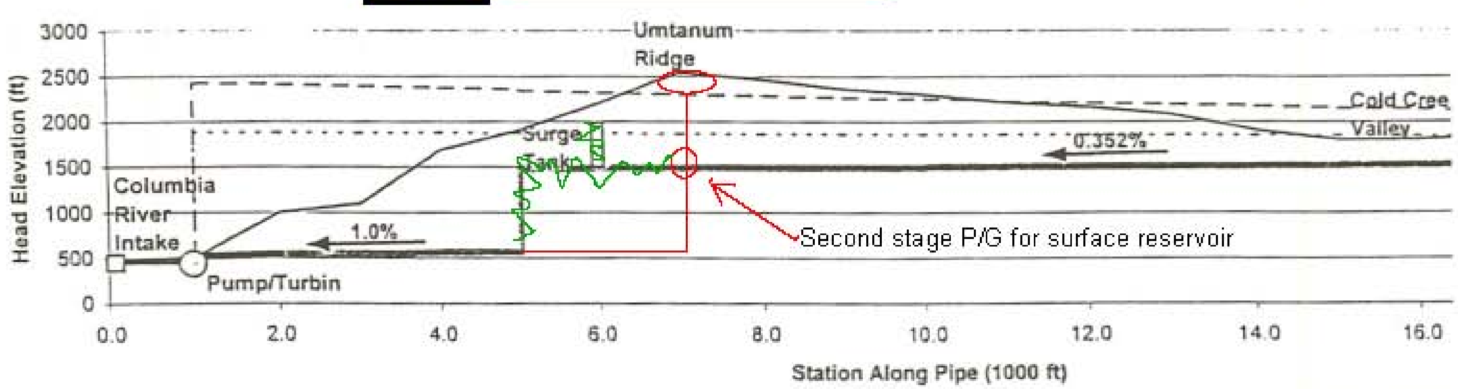
PLAN
SCALE: 1"=3000'-0"

Option A Large underground Reservoir



SCHEMI

Option B Surface Reservoir at 2,500 ft



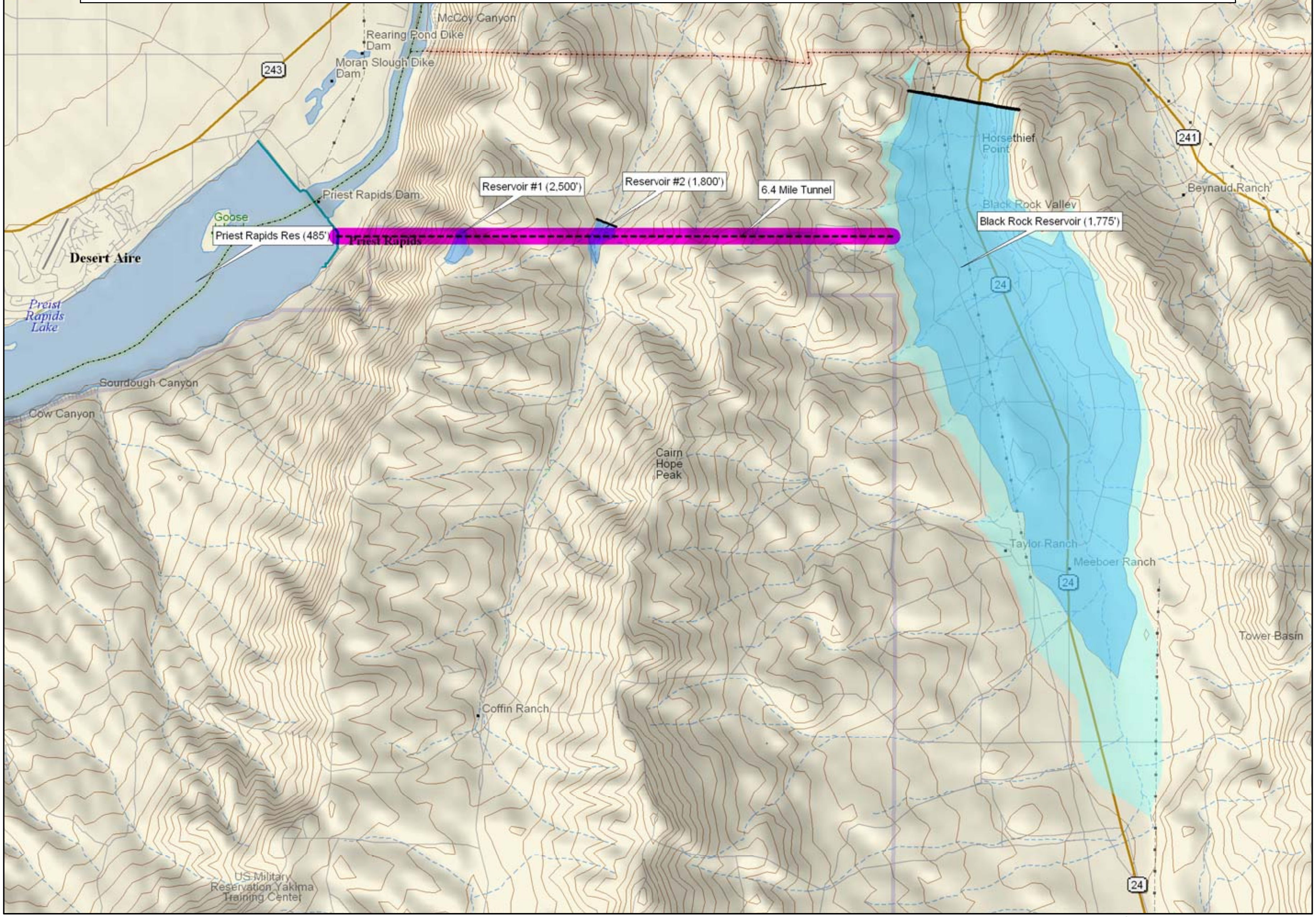
SCHEM

Black Rock Options A & B to Original Configuration for Purposes of Impoving the Project's Pump-Generation's Capabilities

Elevation Profile

- Pressure + Transient Head
- Pressure Head
- Pipe Elevation
- Ground Surface
- Concrete Lined Tunnel/Shaft
- Concrete & Steel Lined Tunnel

Black Rock Reservoir - Alternative Pumped Storage Sites



Scale 1 : 100,000

1" = 1.58 mi Data Zoom 11-0

Prepared by Energy Northwest

<u>View Looking South of Priest Rapids Dam & Umtanum Ridge</u>

<u>Close Up of Umtanum Ridge where Black Rock's Tunnel will go</u>

These Options A & B to the original configuration are for illustration purposes to show possible locations of intermediate storage near the pumping source to increase the dynamic capability of the P/G units and to lessen the losses in a cycle of pumping and then generation. There are many physical locations of intermediate storage or alternative designs of the original USBR Report that might be less expensive to pursue in a follow up study. The addition of either one of these intermediate reservoirs will better enable the pump/generation potential of the Black Rock Project than the original proposal. It is assumed that using single-stage P/G units for Option A or two-stage P/G units for Option B should save enough to help pay for these intermediate reservoir options versus the Report's incremental cost of $190 Million to add separate generation facilities. A thorough analysis of either option (or modifications to the original USBR Report configuration) is beyond the scope of this study, but none-the-less each concept should be looked into from an incremental cost/benefit standpoint.

Power benefits of Surplus Project Capacity:

The Bureau's Report used estimated October 2004 through September 2006 Mid-Columbia power market values to determine the Black Rock Project's pumping costs. This Review used actual daily Mid-Columbia market values for determining the Project's pumping costs and the power benefits associated with P/G facilities. The Project's monthly average pumping schedule came from the Report's Section 8.3.2 "Pumping Energy Requirements and Costs" on Page 130.

The **Roza Canal Power House** seems to be feasible as a matter of course, since it would be generating at 100% during the irrigation season. The **Sunnyside Power House** may be more problematic since this Review assumes it would be operated when irrigation canal requirements exceed the amount of water that can be delivered through the Roza power plant. (See page 135 in the Report for information on the outlet power generation facilities). The **Outlet Generation** facilities would produce about $11.4 Million per year based on an average of FY05 and FY06 Mid-Columbia market prices.

Potential Wind Integration Revenue: There is currently a vast amount of wind power projects in development. This trend is likely to put increasing upward pressure on capacity prices which would favor P/G facilities. The 6,000 MW's of wind capacity predicted for the Northwest will strain not only the BPA transmission system, but also provide the need for more capacity to back up and shape wind energy to match load requirements. BPA's Power Business Line's V.P., Paul Norman in an October 13, 2006 speech to the Oregon PUD Association confirmed that BPA will be hard pressed to meet such a high penetration of wind that is already staining the BPA's capability to accommodate wind. As an example of BPA's limitations to integrate new wind power, the BPA stopped offering a wind shaping product in August 2005 that charged $6/MWh to take in wind one week as generated, and deliver it back on a flat block basis a week later. BPA stopped this service because it is running out of the excess FCRPS capacity necessary to offer these wind integration services. Not a good sign, when several 1,000's of MW's of new wind projects are being planned for integration into the Northwest's power system.

If installed, the Black Rock Project's P/G facilities would be well-situated to provide wind integration services along the Columbia River, East of the Cascades, where most of the new wind power projects are located. The following table is an estimate of the wind integration revenue potential for the Project utilizing the 400 MW's of generation and 500 MW's of pumping, both of which can be used to help integrate wind power. The table assumes that the Project's P/G units' capabilities to perform wind integration services can also complement the Project's pumping requirements. (See Appendix I for key assumptions for this table).

Black Rock P/G Power Benefits	Million $ per year	Notes:
Wind Integration (tied to variable pumping)	20.4	Regulation and/or Operating Reserves
Transmission Congestion Management	0.9	300 hours/year for severe congestion mitigation
Capacity Service (Load Factoring)	2.1	Available 1/2 the time (wind blowing 20% or less)
Month to Month Exchange example	2.3	Assumed April to July every other year
Subtotal	**25.7**	
Plus Outlet Generation	**11.4**	
Total Black Rock Project Power Benefits	**37.1**	**Million $/year**

Pumping costs were calculated to be about $74 million/year.

Therefore, based on the Project's above estimated power benefits, the Black Rock Project's annual pumping costs would be cut in half.

The following table shows how the cost per acre-foot of active storage can be reduced by accounting for the power benefits of the Black Rock Project to offset the pumping costs to refill.

Power Costs for Black Rock Pumping Requirements

Based on FY 2005 & 2006
Without Power Benefits

Avg Power costs	$ 74 Million	= $ 57	per acre-ft
Storage - Million Acre-Ft	1.3	Million ac-ft	

Net Pumping Costs per Acre after subtracting Option A's Power Benefits

Avg Power costs	$ 37 Million	= $ 28.50	per acre-ft
Storage - Million	1.3		

Discussion of Black Rock Project's Option A & B effects on Power Benefits:

It should be noted that the above net pumping cost tables used the Option A "intermediate" reservoir configuration which places an underground reservoir at an elevation of about 1,800 within the nearby Umtanum Ridge. This Ridge rises to the South of the Priest Rapids reservoir which is the source of the pumped storage water. Another option would be Option B which creates an upper pumped storage surface reservoir at 2,500 feet of elevation. By doing so, about 213 MW's of additional pumped storage generation capacity can be obtained using a second single-stage P/G unit, which increases the P/G benefits of the intermediate reservoir over 50%. Since this second P/G unit utilizes a vertical shaft, the net loss cycle should be less than 20%. The following table shows the additional power benefits Option B's P/G units with two stages of P/G.

	Millions of $ per year	
Estimated Black Rock P/G Power Benefits with Option B's Additional 213 MW's of P/G	**$ 39.4**	
Plus Outlet Generation	**$ 11.4**	
Total Black Rock Project Power Benefits	**$ 50.8**	**With Option B**

Option B would reduce the net pumping costs of the Project even further as shown below:

Power Costs for Black Rock Pumping Requirements

Based on FY 2005 & 2006
Without Power Benefits

Avg Power costs	$ 74 Million	=	$ 57	per acre-ft
Storage - Million Acre-Ft	1.3	Million ac-ft		

Net Pumping Costs per Acre after subtracting Option B's Power Benefits

Avg Power costs	$ 23 Million	=	$ $18	per acre-ft
Storage - Million	1.3			

The P/G aspects of the Black Rock Project need additional review because the capacity service premium is increasing and new wind integration will require additional capacity sources. Wind integration should be an additional revenue source for the Black Rock Project.

If the configuration of the Black Rock Project was designed from the beginning for pumped storage to take advantage of capacity service and wind integration opportunities which didn't conflict with the pumping schedule, the project would certainly be more feasible than it currently is from a power standpoint. The pumping required uses the capacity roughly 34% of the time, the capacity service opportunities over the last two years occur roughly 43% of the time and wind power plants average production occurs roughly 32% of the time. By coordinating these uses of the Project's pumped storage capability, then the P/G facilities capacity factor could approach 100%, and thereby reduce the cost of the pumped generator facilities significantly.

Summary of Black Rock Project's Power Benefits Review:

- The Report's estimated $190 million in incremental capital costs for Pump-Generation (P-G) facilities seems high and the design should be revisited. For example, the Report assumes separate pumps from the generators when all of the pump generators in the U.S. currently are reversible pump-turbines.
- Another look at the design for P-G is also necessary to determine if the assumed energy loss in the P-G cycle of 41% can be lowered into the 20% range by using an a different Project configuration. With more efficient P-G units, the Project's dynamic response and integration capacity could support a share of the dramatically increasing wind power generation in the Northwest.
- Using actual market values over the last couple of years, the power costs of the Black Rock Pumped Storage Project are significant at about $74 Million per year.
- Adding generation at the Outlet structures at Roza and Sunnyside in the Yakima Valley can reduce the annual pumping costs by over $11 Million per year. (These Outlet power generation benefits were recognized in the USBR studies).
- However, the USBR studies showed very little additional power benefits with the addition of P-G units, in part because the Project wasn't designed for a more efficient energy loss cycle in the 20% range.
- With more efficient P-G units, the Project's value for wind integration and support for other ancillary power system services is estimated to be about $26 Million per year, although some of these benefits may conflict with each other from time-to-time.
- Therefore, the Black Rock Project's $37 Million per year in combined power benefits could cut the average pumping costs of the Project in half.
- Given that the State of Washington not only needs new critical water storage, it will also need to accommodate the tremendous amount of wind power resources that will be developed due to the recently passed Initiative 937. I-937 mandates that all utilities with 25,000 meters or more must have at least 15% of their power load served by renewable energy resources by 2020.
- The only renewable resource currently available at a reasonable price is wind power located in Eastern Washington. The Black Rock Project could help provide the new capacity needed to integrate the new wind power necessary to accomplish the I-937 Washington State goal for renewable power penetration.

Final notes on the benefits of the Black Rock Project from a power system standpoint:

The NW's transmission system and especially BPA's hasn't substantially changed in 20 years. New wind power generation projects are having a difficult time obtaining transmission access because of congested transmission paths from East to West. Most of the new wind projects are on the East side of the Cascades near the Columbia River and relatively near the Black Rock Project.

The Black Rock Project could help extend the life of certain congested transmission paths by acting as a strategic, centrally located dispatchable "load" when there is too much generation East of the Cascades trying to go to the West side. Installing P-G facilities in the Black Rock Project would add dynamic control benefits to the transmission system -- much like a shock absorber does for an automobile.

The Project could store excess wind power for economic reasons as well as transmission system benefits when wind storms arrive during low market price periods. These low market price periods tend to be when the Columbia River hydroelectric generators are at full capacity during the Spring Runoff and transmission East to West is congested. Once stored, this low value wind power could be released from storage during high market price periods in late summer when transmission is likely to be more available.

As a P-G project, it could also add critical new capacity to the Northwest during extreme peak load conditions in the same manner that Grand Coulee's P/G system presently does.

In summary, the Black Rock Storage Project's ability to generate power benefits needs a second look as a solution to many of the Northwest's looming power system problems. It would be especially useful as a means to integrate the new wind power potential near it in Eastern Washington into the Northwest's power grid, and the same time protect the grid's reliability.

Appendix I

Key Assumptions of Black Rock Project's Power Benefits:

1) Wind power has a 32% plant factor (based on Energy Northwest's Nine Canyon Wind Farm 2003 output).
2) Costs of pumping from the Priest Rapids Dam reservoir source are based on the average daily Mid-Columbia Firm Dow Jones power price index average of FY 2005 and 2006 market costs. (Fiscal Year – FY – used in this Review is from October through September of each year).
3) The market value of Power benefits was calculated on the same basis as #2 above.
4) The pumping schedule was from Table 8-7, page 130 of the Report. The average power required is 192 MW's and the assumed pumping capacity used is 500 MW's which produces a 34% plant factor.
5) The Wind Integration power benefit assumed that during the 34% of time the Project is in the pumping mode, the pumps could be tied to wind integration requirements. For example, when the wind power picked up rapidly, the pumps could back off to soften the impact of the wind power to the system and thereby provide regulation capacity.
6) The value of wind integration capacity is assumed to be the average of BPA's FY07 "Capacity Without Energy" and "Operating Reserves" rates, or $6.11 per KW-month.
7) Wind Integration power benefits calculations did assume some costs to purchase the 20% of P/G cycle losses during periods the pumps aren't pumping.
8) When the wind isn't blowing, then the Project's spare P/G capacity is used for other power benefits above. Other potential power benefits that were not invested include "generation imbalance" and the power value of significant annual water carry over benefits.
9) Nighttime pumping was utilized as much as possible to reduce power costs.
10) The Outlet Hydropower Projects (Rosa and Sunnyside irrigation canal outlets from the project) had 38 MW and 15 MW power plants respectively. The Rosa Power Plant was held at a constant 38 MW's and the Sunnyside Power Plant further down the canal carried additional water per the total irrigation requirements.
11) The Outlet Projects were assumed to be generation only in this review, but could provide additional pump-generation value if so designed.
12) Capacity Service values represent the daily economic gain by purchasing pumping energy at night and then generating during the day with no net energy purchased. This difference between day and night energy prices represents a proxy for capacity value.
13) Not shown are the estimated $4+ million per year loss in annual power generation capabilities of downstream Columbia River hydroelectric projects because of less water in the River due to the Black Rock Project. (See Page 133 of the Report).
14) This Review's goal was to utilize the Project's excess capacity to the maximum extent possible since the pumping requirement only averages 34% of the time. The other 66% of the time, the Project's excess capacity can help integrate wind power and provide other value as a P/G project selling capacity into the market place.