RECLAMATION
Managing Water in the West

Pumped Storage Evaluation Special Study

Yellowtail, Seminoe, and Trinity Sites

Final Phase 2 Report

U.S. Department of the Interior
Bureau of Reclamation Power Resources Office
Denver, Colorado

July 2013

Mission Statements

The mission of the Department of the Interior is to protect and provide access to our Nation's natural and cultural heritage and honor our trust responsibilities to Indian Tribes and our commitments to island communities.

The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.

Pumped Storage Evaluation Special Study

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Volume 1 Phase 2 Report

Prepared by

United States Department of the Interior
Bureau of Reclamation
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Abbreviations and Acronyms

AF	acre-feet
AGC	Automatic Generation Control
BIA	Bureau of Indian Affairs
BLM	Bureau of Land Management
BMPs	Best Management Practices
CAISO	California Independent Systems Operators
cfs	cubic feet per second
CO_2	carbon dioxide
CREAT	Climate Resiliency Evaluation and Awareness Tool
CY	cubic yards
DEQ	Department of Environmental Quality
DFIM	Double-Fed Induction Machine
DOE	Department of Energy
EO	Executive Order
EPA	U.S. Environmental Protection Agency
EPDM	ethylene propylene diene monomer
ESA	Endangered Species Act
FERC	Federal Energy Regulatory Commission
FPP	flexible polypropylene
ft	feet
GCL	Geosynthetic Clay Liner
GIS	Geographic Information System
GTO	Gate Turn Off
HDPE	high density polyethylene
HVAC	Heating, Ventilation, and Air Conditioning
IEGT	Injection Enhanced Gate Transistor
IGBT	Insulated Gate Bipolar Transistor
kW	kilowatts
LLDPE	linear low-density polyethylene
MAAQS	Montana Ambient Air Quality Standards
MCE	Maximum Credible Earthquakes
MEPA	Montana Environmental Policy Act
MOU	Memorandum of Understanding
msl	mean sea level
MW	megawatts
MWh	megawatts per hour
NAAQS	National Ambient Air Quality Standards

NMFS	National Marine Fisheries Service
NPS	National Park Service
NRA	National Recreation Area
NREL	National Renewable Energy Laboratory
O&M	operating and maintenance
OASIS	Open Access Same-Time Information System
PVC	polyvinyl chloride
PWM	Pulse Width Modulated
Reclamation	Bureau of Reclamation
RPS	Renewable Portfolio Standard
SHPO	State Historic Preservation Office
SWRCB	State Water Resources Control Board
TMDL	Total Maximum Daily Loads
USACE	U.S. Army Corps of Engineers
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
VS	Voltage Source
WDH	Wyoming Department of Health
WGFD	Wyoming Game and Fish Department
WHMA	Wildlife Habitat Management Area
WSA	Wilderness Study Area
WSPCR	Wyoming Department of State Parks and Cultural Resources
WSPHST	Wyoming State Parks, Historic Sites, and Trails
WRIM	Wound Rotary Induction Motor

Executive Summary

Introduction and Background

The Bureau of Reclamation (Reclamation) is the largest water supplier in the United States, owning and operating 188 projects across the western states with dams, reservoirs, canals, and other distribution infrastructure. Reclamation is the second largest producer of hydropower in the United States, behind the U.S. Army Corps of Engineers (USACE), and owns and operates 53 hydropower plants that produce over 40,000,000 megawatt hours (MWh) of generation each year.

Reclamation is interested in the potential to develop pumped storage projects at existing facilities. Pumped storage is an efficient means to store energy when the demand for power is low and to generate power with the stored energy when the demand is high. A pumped storage project includes an upper and a lower reservoir. During periods of low demand, water is pumped from the lower reservoir to the upper reservoir. During high demand periods, water from the upper reservoir is released through turbines to the lower reservoir to generate power.

Pumped storage is also recognized as one of the most useful methods for regulating intermittent renewable generation resources, such as wind and solar. Wind and solar energy sources are subject to natural variability that can create challenges for integration into the larger power grid. Wind generation can change suddenly which affects moment-to-moment power output and increases the balancing requirements of dispatchable resources. Peak wind generation also typically occurs during off-peak demand periods and cannot support peak loads. Increased energy storage provided by a pumped storage project would improve grid reliability, avoid transmission congestion periods, and avoid potential interruptions in energy supply.

Reclamation has initiated this *Pumped Storage Evaluation Special Study* to evaluate if a new pumped storage project at existing facilities could be technically and economically viable to support renewable energy integration and energy storage. A viable pumped storage project could help further federal and state renewable energy strategies and objectives.

For this Special Study, Reclamation initially identified four existing reservoir sites within its service area for potential pumped storage. These initial sites were chosen due to their existing infrastructure which included existing upper and lower storage reservoirs, and existing power plant infrastructure. These sites were: Yellowtail/Bighorn Lake, Seminoe and Pathfinder reservoirs in the Great Plains Region, and Trinity Reservoir in the Mid-Pacific Region. After a preliminary screening analysis, Reclamation has selected to continue evaluating potential pumped storage at Yellowtail, Seminoe, and Trinity reservoirs.

Site Descriptions

Yellowtail 5A

The conceptual Yellowtail 5A pumped storage project is approximately 5 miles southwest of Fort Smith in south-central Montana in Reclamation's Great Plains Region (Figure ES-1). As currently configured, the Yellowtail pumped storage project would utilize the existing Bighorn Lake as the lower pool and a newly constructed upper reservoir. New features of the Yellowtail Pumped Storage project includes an upper reservoir, subsurface water conveyance system and below ground power complex, transmission lines, and other appurtenant facilities.

Seminoe 5A2, 5A3 and 5C

The conceptual Seminoe pumped storage projects are approximately 50 miles southwest of Casper, Wyoming in Reclamation's Great Plains Region (Figure ES-2). As currently configured, the Seminoe pumped storage projects would utilize the existing Seminoe Reservoir as the lower pool and a newly constructed upper reservoir. New features would be the same as the Yellowtail Project.

Trinity 5G2A

The conceptual Trinity pumped storage project is approximately 40 miles northwest of Redding, California in Reclamation's Mid-Pacific Region (Figure ES-3). As currently configured, the Trinity pumped storage project would utilize the existing Trinity Lake as the lower pool and a newly constructed upper reservoir. New features would be the same as the Yellowtail Project.

Figure ES-1. Yellowtail 5A Pumped Storage Site Vicinity Map

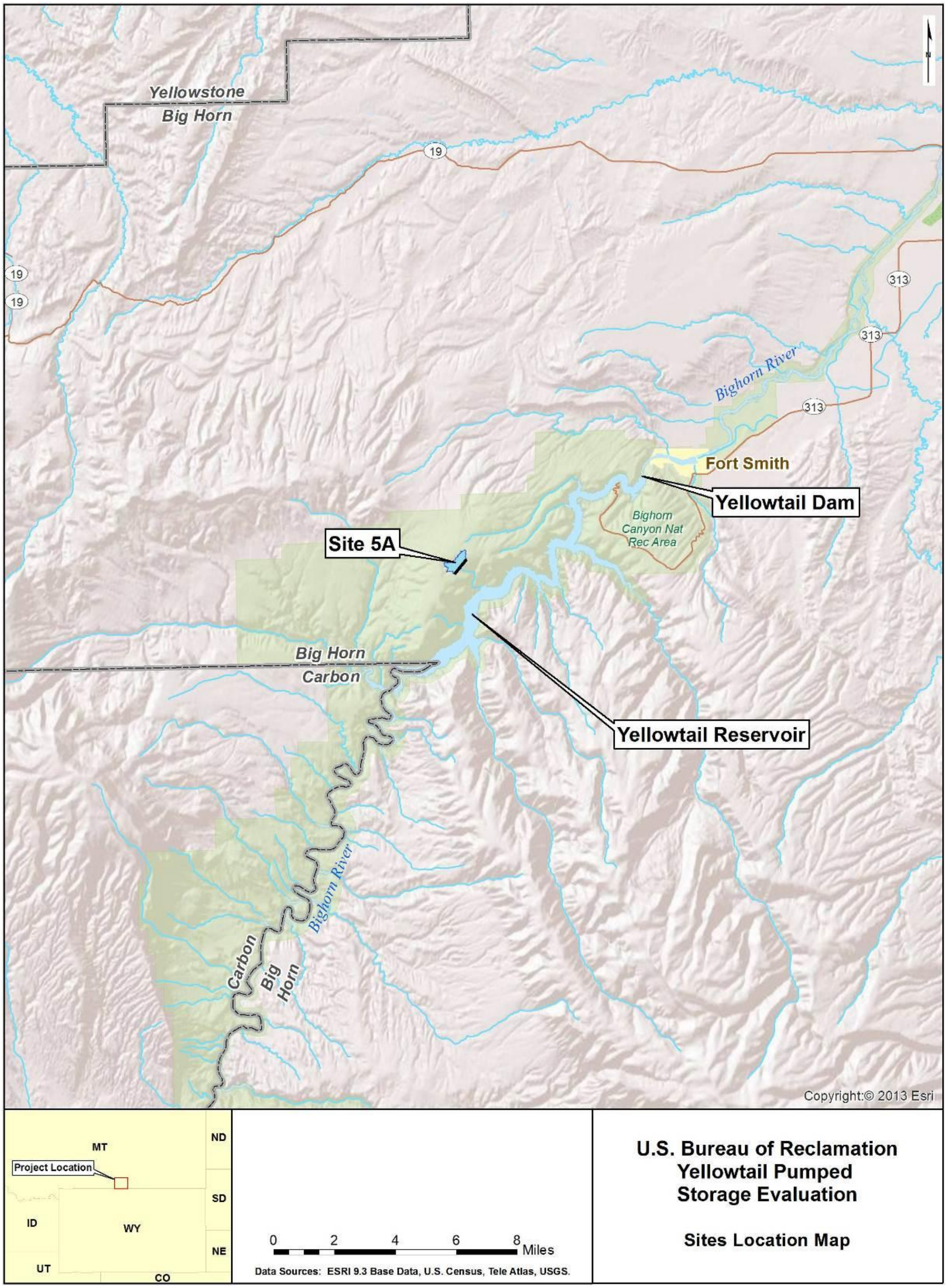


Figure ES-2. Seminoe 5A2, 5A3, and 5C Pumped Storage Site Vicinity Map

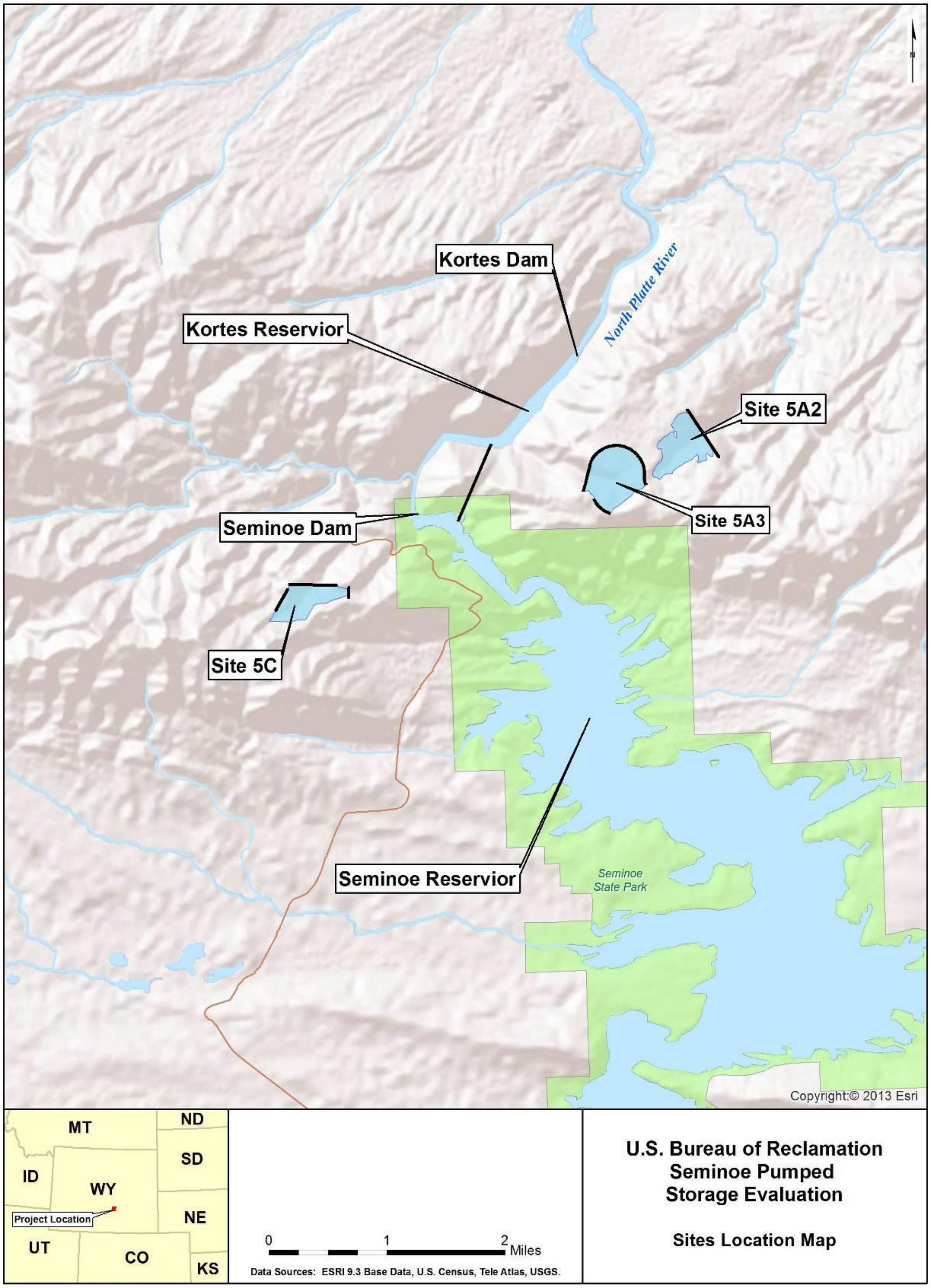
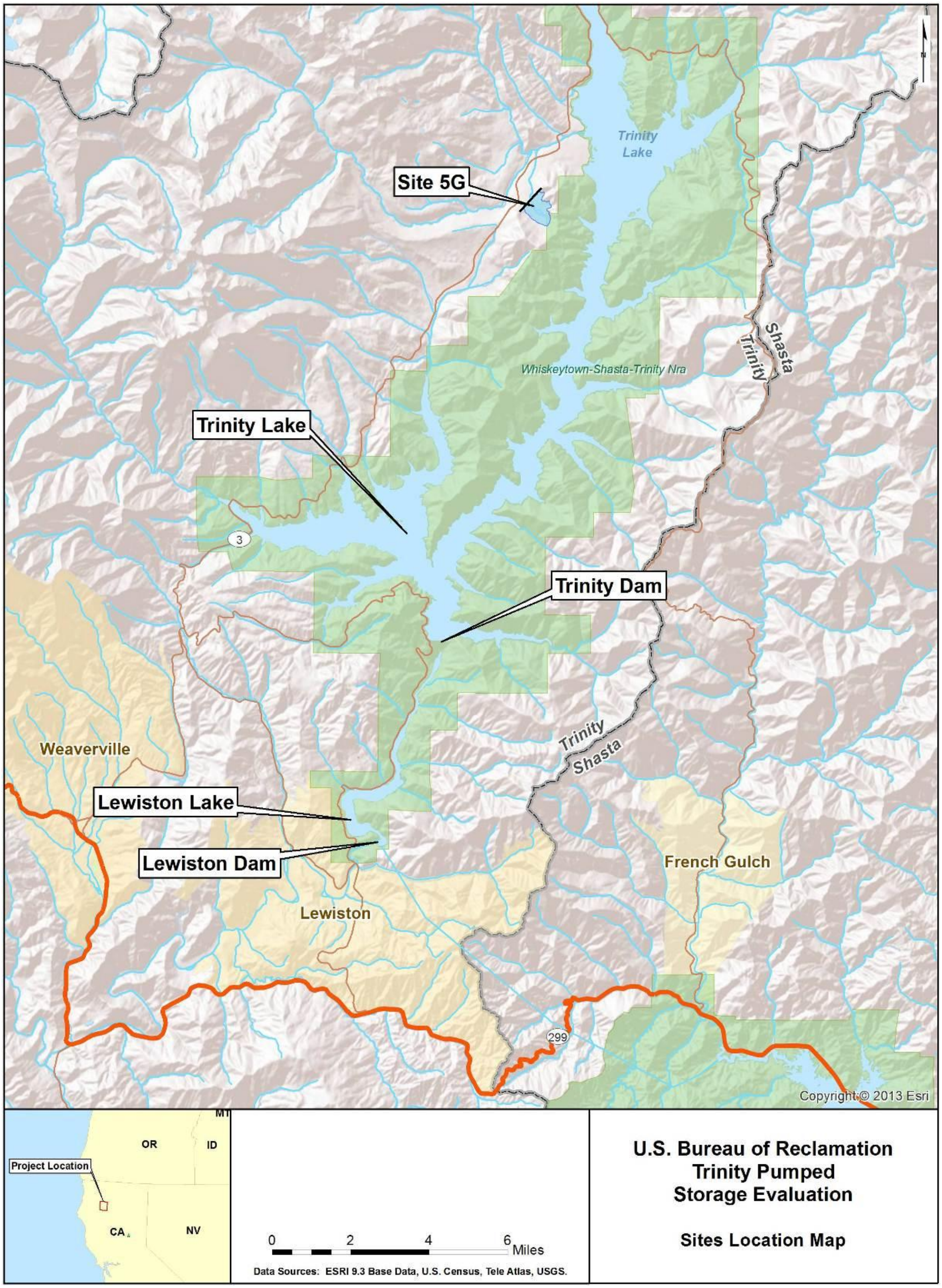


Figure ES-3. Trinity 5G2A Pumped Storage Site Vicinity Map



Site Summary

Table ES-1 contains a list of preliminary site characteristics for each proposed pumped storage project.

Table ES-1. Pumped Storage Project Alternatives - Preliminary Site Characteristics

Assumed Feature (Conceptual)	Yellowtail 5A	Seminoe 5A2	Seminoe 5A3	Seminoe 5C	Trinity 5G2A
Max Upper Reservoir Elev (msl)	5,260	7,290	7,440	7,300	3,105
Min Upper Reservoir Elev (msl)	5,100	7,100	7,250	7,165	3,015
Estimated Dam Fill Volume (CY)	5,987,000	7,000,000	7,380,000	7,231,000	2,912,000
Max Lower Reservoir Elev (msl)	3,657	6,357	6,357	6,357	2,370
Min Lower Reservoir Elev (msl)	3,580	6,290	6,290	6,290	2,200
Upper Reservoir Drawdown (ft)	160	190	190	135	90
Min Head / Max Head Ratio (>.70)	0.86	0.74	0.78	0.80	0.71
Approx. Static Head (ft) (<2650 ft)	1,562	872	1,022	909	775
Maximum Dam Height (ft) (<400ft)	298	407	371	336	139
Required Submergence Below TW (ft)	270	205	205	180	130
Est. Conductor Length (L)	7,950	8,700	6,625	7,160	8,875
Conductor Length (L)/Static Head (H)	5.09	9.98	6.49	7.88	11.45
L/H General Guideline Criteria	< 12	< 12	< 12	< 12	< 12
Upper Reservoir Usable Vol (acre-ft)	12,081	11,202	12,277	7,145	15,022
Lower Reservoir Usable Vol (acre-ft)	336,103	985,603	985,603	985,603	1,859,688
Energy Storage (MWh)	16,601	8,591	11,036	5,716	10,245
Assumed Hours of Storage	10	10	10	10	10
Resulting Installed Capacity (MW)	1,660	859	1,104	572	1,024
Assumed Number of Units	4	4	4	2	4
Tunnel Diameter	1 @ 31 ft	1 @ 38 ft	1 @ 37 ft	1 @ 31 ft	2 @ 30 ft
Penstock Diameter	4 @ 13 ft	4 @ 15 ft	4 @ 14 ft	2 @ 17 ft	4 @ 17 ft

Geology and Seismicity

The sites considered in Phase 2 would require construction of a new off-stream dam and reservoir. Studies at each potential site examined the geology and seismicity to determine fatal flaws or features that could increase construction costs. No fatal flaws related to geology/seismology were identified during this study phase at the proposed Seminoe, Yellowtail, and Trinity sites. Of the three sites, the Seminoe site has the fewest geologic challenges. The following potential geologic/seismologic challenges were identified:

- Yellowtail Site
  - Availability of suitable construction materials is not known at this time and would need to be verified via additional studies.

  - A number of concerning and potentially costly geologic issues were identified related to the presence of soluble limestone underlying the proposed reservoir and dam sites and occurring in the proposed underground excavations.

- Seminoe Sites
  - The sites are in an area of low to moderate seismic risk. Late Quaternary movement has occurred on two sections of the South Granite Mountain fault system to the northwest of the Seminoe Sites. Additional geologic/seismic studies will be needed to assess the potential for strong ground motion at the sites.

- Trinity Site
  - Highly fractured bedrock in the proposed new reservoir rim and underlying the reservoir may present leakage issues.
  - A large area under the footprint of the proposed dam is underlain by alluvial materials; it will require removal before construction of any type of dam due to foundation strength, liquefaction potential, and seepage under the dam.
  - Suitable construction materials for a concrete-faced rock fill dam are not present in the reservoir area.

Single-Speed versus Variable-Speed Technology

A typical pumped storage plant uses electricity to pump water to the upper reservoir during periods of low-cost, off-peak power and generates electricity during periods of high-cost, on-peak power. In the case of conventional synchronous (single, constant speed) pump-turbine units, during generating mode, the individual units are operated to support grid requirements including load following; however, during pumping, the units are operated at best pumping gate (most efficient operation) with no capability for load following or regulation. During pumping mode, the wicket gate positions may need to be decreased as the reservoir water elevation increases in order to keep the units on the best pumping gate curve and to prevent cavitation and vibration (net head control). Deviation from this best pumping gate operation results in low efficiency and rough operation, with minimal change in power input requirements.

In the case of variable-speed (asynchronous) pump-turbine units, load following is possible during both the generating and pumping modes, and hence the primary difference between the two technologies. Variable-speed operation in this context normally means that the rotating speed of a unit does not vary by more than +/-10% of its synchronous speed. The varying output frequency of the generator is converted to the grid frequency through a special frequency conversion system. Other advantages of variable-speed units are higher and flatter generator efficiency curves, wider generating and pumping operating ranges, and easier start-up process. The main disadvantage of this technology is the higher capital costs, which are on average about 30% greater than conventional single-speed units.

Table ES-2 provides a summary comparing the operational characteristics and advantages/disadvantages of single and variable-speed units for this particular project. Actual benefits will vary depending on specific site characteristics. Because of the multiple advantages, variable-speed units have been incorporated into the facility designs.

Table ES-2. Example Comparison of Primary Characteristics

Characteristic	Single-speed	Variable-speed
Proven Technology	45+ years - Worldwide	10+ years - Europe and Japan
Equipment Costs		Approximately 30% to 50% Greater
Powerhouse Size		Approximately 25% to 30% Greater
Powerhouse Civil Costs		Approximately 20% Greater
Project Schedule		Longer - Site Specific
O&M Costs		Greater
Operating Head Range	80% to 100% of Max. Head	70% to 100% of Max. Head
Generating Efficiency		Approximately 0.5% to 2% Greater
Power Adjustment Generation Mode	Approximately 60% to 100%	Approximately 50% to 100%
Power Adjustment Pump Mode	None	+/- 20%
Operating Characteristics		
Idle to Full Generation	Generally Less than 3 Minutes	Generally Less than 3 Minutes
100 Percent Pumping to 100 Percent Generation	Generally Less than 6 to 10 Minutes	Generally Less than 6 to 10 Minutes
100 Percent Generation to 100 Percent Pumping	Generally Less than 6 to 10 Minutes	Generally Less than 6 to 10 Minutes
Load Following	Seconds (i.e., 10 MW per Second)	Seconds (i.e., 10 MW per Second)
Reactive Power Changes	Instantaneously	Instantaneously
Automatic Frequency Control	No	Yes

Operating Characteristics

The potential pumped storage projects will produce energy arbitrage and ancillary services. Energy arbitrage refers to the practice of utilizing electric energy during the lower priced, off-peak hours to pump water from a forebay into the new upper reservoir. The water is then stored in the upper reservoir for potential use. When energy prices are higher, water is released from the upper reservoir through the turbines, and electricity is generated and sold at these higher prices. Energy arbitrage results in higher net income when the difference between on-peak and off-peak prices is greatest. Typically, energy prices are lowest during off-peak hours and are highest during the on-peak hours.

The projects would also provide ancillary services. The Federal Energy Regulatory Commission defined ancillary services as, “those services necessary to support the transmission of electric power from seller to the purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system” (FERC 1995). As described above, variable-speed units are more suitable for providing ancillary services than single-speed units, particularly regulation. The projects could provide the following services:

- Spinning Reserves - Reserved capacity provided by generating resources that are running (i.e., “spinning”) with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours. Spinning Reserves are needed to maintain system frequency stability during emergency operating conditions and unanticipated variations in load.
- Non-Spinning Reserves - Generally, reserved capacity provided by generating resources that are available but not running. These generating resources must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then be able to run for at least two hours. Non-Spinning Reserves are needed to maintain system frequency stability during emergency conditions.
- Regulation - Reserved capacity provided by generating resources that are running and synchronized with the grid, so that the operating levels can be increased (incremented) or decreased (decremented) instantly through Automatic Generation Control to allow continuous balance between generating resources and demand.

Table ES-3 shows the total market products for each site. The sections below describe additional operational issues in more detail.

Table ES-3. Summary of Preliminary Total Station Market Products

	Generate Mode			Pump Mode		
	Min MW	**Max MW**	**Incremental Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**
Yellowtail 5A						
@ Min. Head	166	1604	1438	328	1808	1480
@ Max Head	85	1660	1575	380	1808	1428
Seminoe 5A2						
@ Min. Head	86	542	456	167	860	693
@ Max Head	43	860	817	177	936	760
Seminoe 5A3						
@ Min. Head	110	776	665	226	1,140	914
@ Max Head	55	1,104	1,049	239	1,202	963
Seminoe 5C						
@ Min. Head	114	407	293	223	590	367
@ Max Head	57	572	515	252	622	370
Trinity 5G2A						
@ Min. Head	102	847	744	218	1,064	846
@ Max Head	51	1,024	973	224	1,119	895

Spinning and Non-Spinning Reserves

The units will have the capability to be in a constant spin state. When not generating or absorbing power, the units can be in synchronous condense mode and be eligible for spinning reserves consideration. The units will be able to reach full range of operations for spinning reserves in less than three minutes in the generation mode and less than four minutes in the pump mode. The units will be able to reach full range of operations for non-spinning reserves in less than six minutes in the generation mode and less than eight minutes in the pump mode.

Generating and Pumping Flexibility

The Yellowtail and Seminoe sites have only one power tunnel; therefore, all units must be moving water in the same direction. In other words, if one unit is in generation mode, the remaining units can provide additional generation capability, or be in synchronous condense mode (either generating or pumping mode). These projects, as currently conceived, do not have the capability to allow simultaneous generating and pumping.

The Trinity site has two power tunnels, with two units for each tunnel. For a given power tunnel, if one unit is in generate mode, the remaining unit can provide additional generation capability, or be in synchronous condense mode (either generating or pumping mode). The project, as currently conceived, has the capability to allow simultaneous generating and pumping.

Transmission Studies

The transmission studies evaluated transmission limits at each of the existing facilities and required upgrades to connect each potential pumped storage site to the transmission grid. Detailed analysis of system impacts and transmission deliverability was not considered in this high level study, but will need to be confirmed through additional study for the projects to proceed. The studies generally considered options to construct a short 230 kV line to connect to existing facilities at the sites, a longer 230 kV line to connect to facilities with more capacity, or a 500 kV line. The first transmission line (the shorter 230 kV line) is capacity-limited at all sites, and would not allow the pumped storage sites to operate at full capacity. The studies found the following transmission options to maximize transmission capacity and minimize costs:

- **Yellowtail:** The 500 kV transmission option is superior to the 230 kV transmission options considered for Yellowtail 5A. A single-circuit 500 kV line provides better voltage regulation, reduced losses, and is slightly less expensive than the multiple 230 kV circuits. Interconnection at the Broadview 500 kV switchyard would require one 500 kV bay at the Broadview 500 kV bus, and one 500 kV line approximately 60 miles connecting to the Yellowtail 5A site with new 500 kV GSU. Deliverability of the project output across the Colstrip 500 kV system will need to be confirmed by additional system impact studies.

- **Seminoe:** The 500 kV transmission option and the 230 kV transmission option perform about equally well for the Seminoe sites; however, the 500 kV option costs nearly twice as much as the 230 kV option. In this scenario, the 230 kV option requires only a single double circuit 230 kV line for a significant cost savings. One double circuit line with breakers at each end would provide line and generator protection, leading to 40 miles of double circuit 230 kV line. The study also assumed four 230 kV line bays: two each at the new Seminoe sites and at the Aeolus 230 kV switchyard. Deliverability of the project output across the Gateway 500 kV system will need to be confirmed by additional system impact studies.
- **Trinity:** The 500 kV transmission option and the 230 kV transmission option perform equally well for the Trinity 5G2A site, but the 230 kV option is slightly less expensive. One double-circuit line with breakers at each end would provide line and generator protection, leading to 60 miles of double circuit 230 kV line. The study also assumed four 230 kV line bays: two each at the new site and at the Olinda 230 kV switchyard. The analysis of the interconnection at the Olinda 230/500 kV Substation did not consider transmission deliverability across the grid, which may be an issue in this location. The transmission system comprising the California-Oregon Border interface is often congested due to high imports from the northwest, so the addition of this large project will require additional detailed studies to determine regional transmission system impacts.

Opinion of Probable Costs

Table ES-4 shows the opinion of probable cost based on conceptual layouts and transmission facilities for each site. Table ES-5 shows potential operations and maintenance costs.

Project Schedule

The project schedule will be dependent on many factors such as technology, site characteristics and subsurface conditions, as well as environmental and regulatory complications. However, the following development schedule could be reasonably assumed:

Phase	**Schedule**
Engineering studies, site characterization, and permits	2+ years
Detailed engineering and construction planning	2+ years
Construction and startup testing	3-5 years

Table ES-4. Opinion of Probable Cost Summary (Million $)

	Yellowtail 5A	**Seminoe 5A2**	**Seminoe 5A3**	**Seminoe 5C**	**Trinity 5G2A**
Land and Land Rights	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1
Upper Reservoir and Dams					
Dam	$134.71	$157.50	$166.05	$162.70	$65.52
Stream Diversion	$5.00	$5.00	$5.00	$5.00	$5.00
Upper Reservoir Liner	$4.00	-	-	-	-
Spillway	$5.00	$5.00	$5.00	$5.00	$5.00
Civil Works					
Power Station - Civil	$199.21	$164.95	$180.99	$125.75	$225.39
Upper Reservoir Intake	$6.60	$12.00	$11.70	$6.60	$13.20
Vertical Shaft	$26.10	$12.60	$19.95	$12.35	$26.51
Horizontal Power Tunnel	$65.10	$96.00	$60.00	$46.50	$144.00
Penstocks	$27.00	$15.12	$18.00	$9.72	$20.28
Draft Tube Tunnels & DT Gates	$24.90	$23.10	$21.00	$14.70	$28.80
Tailrace Tunnels	$51.60	$73.50	$52.50	$31.35	$109.20
Discharge Structure & Channel	$39.00	$35.40	$39.00	$22.50	$49.20
Surge Chamber	-	$66.10	-	-	$98.64
Draft Tube / Transformer Gallery	$26.00	$26.00	$26.00	$13.00	$26.00
Access Tunnels	$21.60	$18.72	$18.72	$18.72	$19.44
Underground Haul Tunnels	$12.00	$12.00	$12.00	$12.00	$12.00
Site Roads	$5.60	$5.60	$5.60	$11.10	$11.10
Miscellaneous civil works and structures	$25.00	$25.00	$25.00	$25.00	$25.00
Power Plant Equipment	$697.24	$463.92	$573.87	$310.93	$545.03
Switchyard	$42.00	$24.00	$24.00	$10.50	$24.00
Transmission - Plant to Interconnect	$15.00	$2.40	$3.00	$3.60	$18.00
Transmission - Infrastructure Upgrades	$122.50	$41.60	$41.60	$41.60	$70.60
Subtotal	$1,555.16	$1,285.50	$1,308.99	$888.62	$1,541.90
Temporary Facilities & Site Prep	$77.76	$64.27	$65.45	$44.43	$77.10
Subtotal Direct Costs	$1,632.92	$1,349.77	$1,374.43	$933.05	$1,619.00
Contingency (20%)	$326.58	$269.95	$274.89	$186.61	$323.80
Indirect Costs (20%)	$326.58	$269.95	$274.89	$186.61	$323.80
Total Construction Costs (2) (3)	$2,286.08	$1,889.68	$1,924.21	$1,306.27	$2,266.60
Estimated Cost (million $/MW)	$1.38	$2.20	$1.74	$2.29	$2.21
Cost Ranking (based on $/MW)	1	3	2	5	4

1. Costs not included at this level of analysis.
2. Cost estimates are AACE Class 4 estimates with 20 percent contingency.
3. Cost estimates are in 2012 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.

Table ES-5. Estimated O&M Costs

Alternative		Installed Capacity (MW)	Annual Energy (GWh)	1985 O&M Costs ($)	Index Factor	2012 Total Est. Costs($)
Yellowtail	5A	1,660	3,636	5,600,000	2.5	4,000,000
Seminoe	5A2	859	1,881	3,600,000	2.5	9,000,000
	5A3	1,104	2,417	4,300,000	2.5	10,750,000
	5C	572	1,252	2,800,000	2.5	7,000,000
Trinity	5G2A	1,024	2,244	4,100,000	2.5	10,250,000

Operational Studies

The operations studies of the potential pumped storage sites used an operations model to simulate potential operations and income. The operations model is fundamentally a mass balance model that tracks the storage of the new reservoir and existing forebay reservoir, as well as any pumped or generation flows exchanged between the two reservoirs, for each model time step. Operation schedules – the timing and duration of pumped and generation operation – can be established to take advantage of electricity price differentials during a day to maximize revenue. The operations model also includes the assessment of income generated from 4 ancillary services: regulation up and down, spinning and non-spinning reserves.

For each site, the modeling for the baseline scenario provided information to optimize how much of the facility would be used for energy arbitrage and ancillary services. Generally, arbitrage helped maximize income during the hotter months with a higher peak and off-peak differential, but the winter months only included ancillary services. Figures ES-4 through ES-6 show the average weekly income at each site. Only Seminoe 5A3 is included here because it provides the greatest income and has the lowest costs; Chapter 9 includes baseline information for Seminoe 5A2 and 5C sites as well.

Figure ES-4. Average Weekly Income for Yellowtail under Baseline Scenario

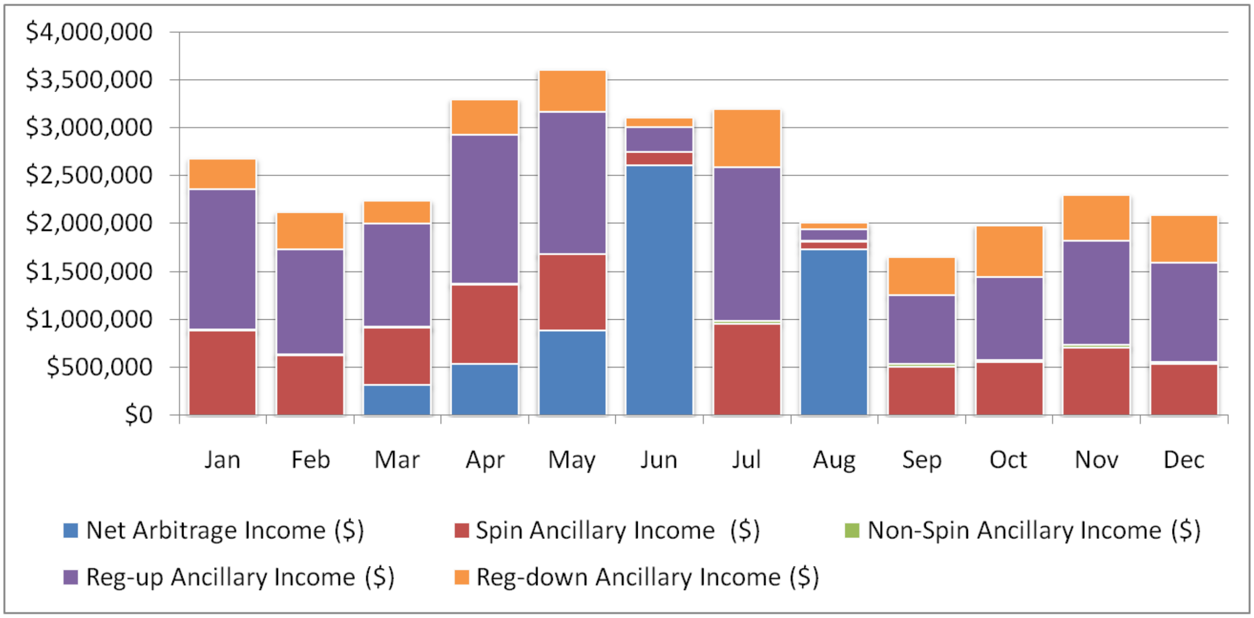


Figure ES-5. Average Weekly Income for Seminoe 5A3 under Baseline Scenario

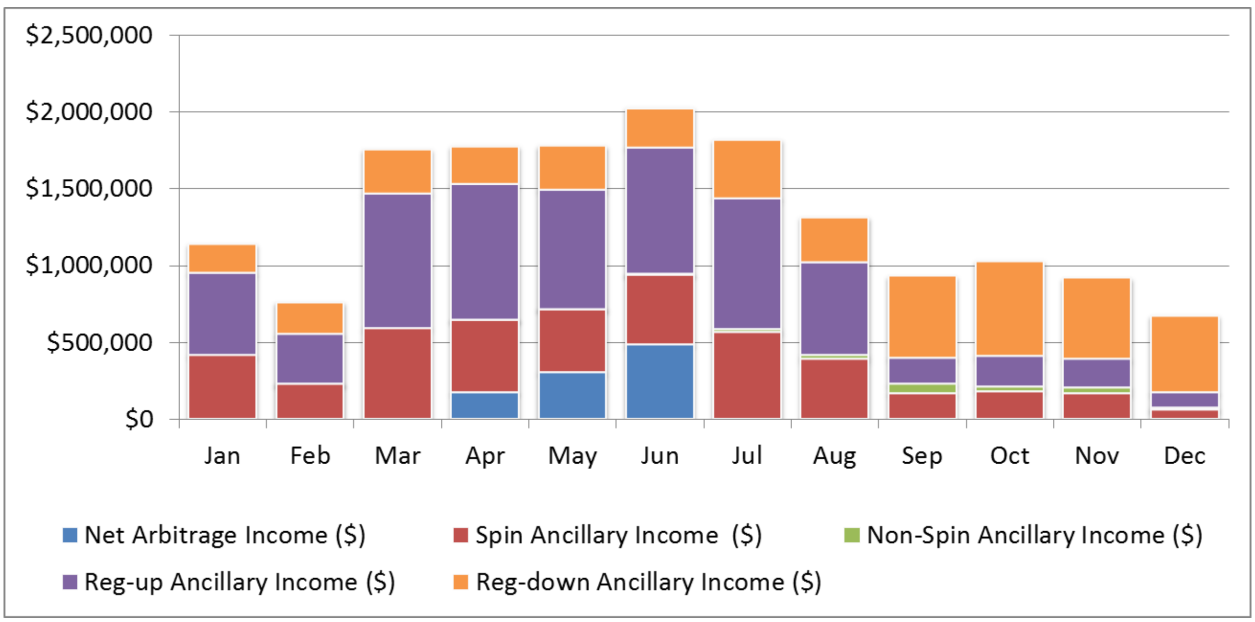
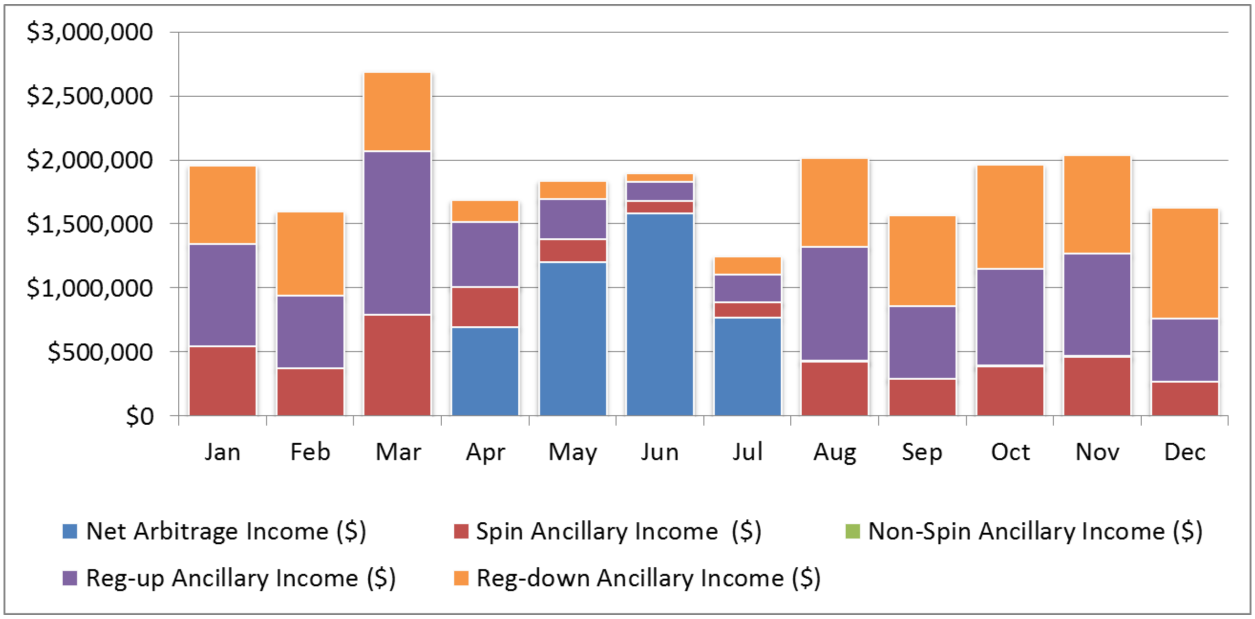


Figure ES-6. Average Weekly Income for Trinity under Baseline Scenario



The operational studies also considered five different scenarios to understand the sensitivity of the operations model to different parameters. Analysis of these scenarios contributed to the following conclusions:

- Pumped storage projects would result in very small changes to water levels in the existing forebay reservoirs, even in very dry hydrologic conditions. Maximum water level changes would be approximately one foot at most sites and up to two feet in dry years at the Yellowtail site.
- At most sites, arbitrage only represents the best way to maximize income in one or two hotter months. The baseline scenario, however, incorporated arbitrage in other months because it was profitable based on energy prices (though may not maximize income relative to an ancillary services only operation). These months were included because it is assumed that local utilities would need additional energy in the future to meet peaking demands. Additionally, having some level of pumping or generating can help the system respond instantaneously for regulation services.
- Changes in energy prices associated with increased costs to meet carbon dioxide regulatory requirements would have relatively small effects on total income. These changes, however, would reduce the difference between peak and non-peak energy prices in some months and would reduce the use of arbitrage compared to the baseline scenario.
- Results are sensitive to changes in ancillary service prices. There is much uncertainty in future ancillary service prices because markets are

young or not yet established. If ancillary service prices increase at a similar rate than energy costs to meet carbon dioxide regulatory requirements, pump storage projects would be more economically viable, but still may not generate a positive net income.

- Climate change projections for each reservoir site predict a range of changes in precipitation, but they would generally have a relatively small effect on reservoir levels in the existing forebay reservoirs. Given the minimal projected impact of climate change in precipitation and runoff, climate change conditions (as predicted by the models used in this analysis) would most likely not have an impact on the pumped storage operations.

Economic Evaluation

The economic evaluation compares the costs and benefits of the proposed pumped storage projects and calculates a benefit-cost ratio under various operating scenarios. The economic evaluation also discusses existing energy market conditions and how the proposed projects would fit into existing market conditions.

Costs and Benefits

Economic benefits are accrued when the pumped storage project sells energy or provides ancillary services. The operations model estimates the amount of energy generated through arbitrage and the level of ancillary services available. Costs include the net present value of costs for construction, transmission upgrades, O&M, replacement, and pumping energy over the 50-year period of analysis. The economic analysis calculates a benefit-cost ratio and net benefits (or costs) for each of the proposed projects. The benefit-cost ratio compares the present value of benefits to costs over the 50-year period, using the 2013 federal discount rate of 3.75 percent. A benefit-cost ratio greater than 1.0 indicates that the project could be economically viable and may warrant further study. Table ES-6 shows the base case benefit and cost calculations for each site.

Table ES-6. Benefit and Cost Summary (Million $)

	Yellowtail 5A	Seminoe 5A2	Seminoe 5A3	Seminoe 5C	Trinity 5G2A
Present Value Costs	$2,402.39	$1,935.7	$2,002.20	$1,354.2	$2,310.6
Present Value Benefits	$2,216.41	$667.3	$1,174.46	$557.4	$1,672.3
Net Benefits/(Costs)	($185.98)	($1,268.4)	($827.74)	($796.8)	($638.3)
Benefit/Cost Ratio	0.92	0.34	0.59	0.41	0.72
Annualized Costs	$107.08	$86.3	$89.25	$60.4	$103.0
Annualized Benefits	$98.79	$29.7	$52.35	$24.8	$74.5

The economic evaluation also considered how the costs and benefits would change under the different scenarios modeled with the operations model. Some of these scenarios (particularly those that escalated prices for the ancillary services) resulted in increased benefits. For the Seminoe and Trinity sites, the benefit-cost ratios were still well under 1.0 for all scenarios. For the Yellowtail site, the scenario with escalated ancillary services at the same rate as energy prices with CO_2 regulatory costs yielded a ratio above 1.0. This is the most favorable price scenario tested and is not expected to occur in the near future.

Market Evaluation

Reclamation has indicated that the primary objective for the proposed pumped storage projects would be to market ancillary services; selling arbitrage energy would be a secondary objective. The operations model results support this objective showing that providing ancillary services would be the more profitable operation relative to energy arbitrage. The base case scenarios for each site typically include little arbitrage only when energy prices support the operation. Given that the projects would target marketing ancillary services, it is important for them to be in areas with high development of renewable resources, which require energy storage.

Yellowtail

Montana’s renewable energy goals are being met by proactive policies of Northwestern Energy, the major public utility in the state, and other local utilities. There is no developed ancillary services market in the state, which makes it difficult to support a large capital investment for pumped storage. Montana also does not have the urban demand centers that would justify a pumped storage project the scale of Yellowtail. Substantial investment would need to be realized in transmission facilities in order to market arbitrage and ancillary services to load centers in the Northwest power markets.

Seminoe

Wyoming is a state with substantial wind generation potential. For the potential to be developed, major increases in bulk storage for load management would be required in the future. However, Wyoming currently does not have an established ancillary services market, which is a significant challenge to implementing a large-scale energy storage project. Wyoming does not have the population base to support a large scale increase in power production. Therefore, increases in new electrical capacity, over and above load growth, would need major increases in transmission capacity to load centers in the Northwest and Southwest. The project could connect to the planned Gateway West Transmission Line Project, but further system impact studies need to be completed to confirm.

Trinity

The existence of an ancillary services market in California supports the potential for a pumped storage project to support renewable energy integration, more so than in Montana and Wyoming. The Trinity site would be connected to the California-Oregon intertie, which is often congested due to high imports. There may need to be substantial transmission infrastructure upgrades to support his large of a project.

Environmental Considerations

The proposed volume of water that would be pumped into the new reservoir would be very small relative to the volume of water in the existing reservoirs, so it would not noticeably change the volume of water in storage or flow downstream from the reservoirs. Therefore, pumped storage operations would not be likely to substantially affect resources dependent on reservoir volume or downstream flow, such as fisheries, surface water resources, and water-related recreation. Some other key resources would experience similar effects at all sites:

- Vegetation and Wildlife: the three sites for new reservoirs are natural, undeveloped areas, and the new reservoirs would inundate areas that contain a wide variety of vegetation and wildlife. Construction would also cause temporary impacts from removal of vegetation, as well as dust, noise, and vibration impacts.
- Water Quality: construction could increase sediment contributions to the waterways, but implementation of Best Management Practices would limit these contributions. Long-term pumped storage operations could cause slight increases in temperature as water is conveyed between reservoirs.
- Cultural Resources: construction activities such as excavation and tunneling have the potential to damage or unearth cultural and/or paleontological resources. Creation of the new reservoirs may

permanently inundate known or previously unknown cultural or paleontological resources.

The sections below summarize unique and challenging environmental issues at each site.

Yellowtail

Construction of the new reservoir would occur on the Crow Tribe's land holdings within the Bighorn Canyon National Recreation Area (NRA). The tribe could be affected by temporary, construction-related impacts (such as dust, noise, traffic, and disturbance of artifacts) and permanent impacts associated with inundation of the land and vegetation under the reservoir.

No roads provide direct access to the pump storage site, so the alternative would require a new permanent access road constructed through difficult terrain because of changes in elevation. The access road would likely need to be constructed on the Crow Reservation and on the Crow Tribe's land holdings within Bighorn Canyon NRA. Reclamation must also obtain a water rights permit to operate the pumped storage project, which cannot conflict with the Montana-Crow Tribe Compact that defines water rights for Bighorn Lake.

Seminoe

Seminoe 5C would be within the Morgan Creek Wildlife Habitat Management Area (WHMA), managed by the Wyoming Game and Fish Department. The new reservoir could have construction-related impacts and long-term impacts (associated with the presence of a new dam, reservoir, and associated facilities) to vegetation and wildlife in this area. Construction would also limit access to recreational opportunities within the Morgan Creek WHMA.

Seminoe 5A2 would be constructed on Bureau of Land Management lands in the Bennett Mountain Wilderness Study Area (WSA). The WSA is meant to remain in a natural state without man-made structures and should allow for solitude and primitive recreation. The Bennett Mountain WSA was not recommended for wilderness status in a 1992 report to Congress; however, Congress has not made a ruling on any of the WSAs. Until Congress makes a final determination on a WSA, the Bureau of Land Management continues to manage the area to preserve its suitability for designation as wilderness.

Construction of Seminoe 5A2 could conflict with the WSA designation. The presence of a new dam, reservoir, and associated facilities would be considered a long-term adverse effect on the overall wilderness recreation experience. Construction of this site would require a new permanent access road through the Bennett Mountain WSA, which would impair suitability of the wilderness area and would not be compatible with its current designation as a WSA.

Trinity

The Trinity River Restoration Program was established in 2000 in response to multiple studies on the decline of salmon and steelhead populations in the Trinity River following the construction and operation of the Trinity River Division of the Central Valley Project in 1964. The Trinity River Restoration Program established a variable flow management regime to mimic more natural flows along with channel rehabilitation, sediment management and watershed restoration actions to improve habitat suitability for the salmon and steelhead populations. Fish populations in the Trinity River and Klamath River downstream are still however susceptible to stresses from high water temperatures and low water flows. In September 2002, at least 33,000 adult salmon, many of which were headed to the Trinity River to spawn, died in the mainstem of the Klamath River downstream of the Trinity River. Later studies on the die-off identified low flows and high water temperatures and their promotion of a fish disease as the primary cause of this event. While the temperature increases associated with the Trinity pumped storage site are likely to be very small, they would be of great concern because of the current efforts for fish restoration within the basin.

Conclusions

The five sites analyzed in this study (Yellowtail 5A, Seminoe 5A2, Seminoe 5A3, Seminoe 5C, and Trinity 5G2A) have an ability to generate power through energy arbitrage and ancillary services; however, none of the sites have positive net benefits under the base case scenario. The Yellowtail site shows some potential if ancillary services would increase at unusually high escalation rates. All sites have geologic and environmental concerns that could increase costs or the difficulty of permitting and construction. Each site also requires some transmission infrastructure upgrades to transmit energy to demand centers. None of these sites are recommended to move forward for additional study at this time.

For the next steps in the process, the analysis is recommended to build on the lessons learned from this analysis to decrease costs or increase benefits from the projects. Reclamation should continue to monitor ancillary service markets and prices to understand how they might further develop or change in the future. An initial screening effort could focus on these topics to try to narrow down a broad list of sites to a smaller list for more detailed evaluation:

- **Identify sites with a suitable L/H (operating head over water conductor length) ratio**. Finding a site that has a large elevation change at a short distance from the existing forebay reservoir would help reduce costs of the facilities.

- **Use large existing reservoirs**. The operations model found that pumped storage operations result in very small changes to water levels or volumes in the existing forebay reservoirs because the reservoirs are much larger than the proposed new reservoirs. Using a smaller reservoir would increase the likelihood that pumped storage operations could affect water supply for downstream environmental needs and water users.
- **Focus on sites in the Pacific Northwest, California, or Arizona**. These areas have a widespread transmission system that would help reduce the high transmission costs associated with the sites in this study. Additionally, ancillary service markets are likely to be established in these areas because of the large demand centers and focus on renewable energy.
- **Locate projects in areas with high potential for wind power development**. Pumped storage projects have maximum benefits when they can integrate with other renewable resources, such as wind power.

Chapter 1 Introduction

1.1 Project Background

The Bureau of Reclamation (Reclamation) is the largest water supplier in the United States, owning and operating 188 projects across the western states with dams, reservoirs, canals, and other distribution infrastructure. Reclamation is the second largest producer of hydropower in the United States, behind the U.S. Army Corps of Engineers (USACE), and owns and operates 53 hydropower plants that produce over 40,000,000 megawatt hours (MWh) of generation each year..

Reclamation is interested in the potential to develop pumped storage projects at existing facilities. Pumped storage is an efficient means to store energy when the demand for power is low and to generate power with the stored energy when the demand is high. A pumped storage project includes an upper and a lower reservoir. During periods of low demand, water is pumped from the lower reservoir to the upper reservoir. During high demand periods, water from the upper reservoir is released through turbines to the lower reservoir to generate power.

Pumped storage is also recognized as one of the most useful methods for regulating intermittent renewable generation resources, such as wind and solar. Wind and solar energy sources are subject to natural variability that can create challenges for integration into the larger power grid. Wind generation, particularly, can change suddenly, which affects moment-to-moment power output and increases the balancing requirements of dispatchable resources. Peak wind generation also typically occurs during off-peak demand periods and cannot support peak loads. Increased energy storage provided by a pumped storage project would improve grid reliability, avoid transmission congestion periods, and avoid potential interruptions in energy supply.

Reclamation has initiated this *Pumped Storage Evaluation Special Study* to evaluate if a new pumped storage project at existing facilities could be technically and economically viable to support renewable energy integration and energy storage. A viable pumped storage project could help further federal and state renewable energy strategies and objectives.

For this Special Study, Reclamation initially identified four existing reservoir sites within its service area for potential pumped storage. These initial sites were chosen due to their existing infrastructure which included existing upper and lower storage reservoirs, and existing power plant infrastructure. These sites were: Yellowtail/Bighorn Lake, Seminoe and Pathfinder reservoirs in the Great

Plains Region, and Trinity Reservoir in the Mid-Pacific Region. After a preliminary screening analysis, Reclamation has selected to continue evaluating potential pumped storage at Yellowtail, Seminoe, and Trinity reservoirs.

1.1.1 Federal Memorandum of Understanding for Hydropower

On March 24, 2010, the U.S. Department of the Interior, Department of Energy and the Department of the Army (through USACE) signed a Memorandum of Understanding (MOU) for Hydropower to advance mutual goals for the development of clean, reliable, cost-effective, and sustainable hydropower generation nationwide. The MOU identifies seven categories with associated actions that can help achieve hydropower goals. The seven categories include:

A. Federal facility energy resource assessment
B. Integrated basin-scale opportunity assessments
C. Green hydropower certification
D. Federal Inland Hydropower Working Group
E. Technology development and deployment
F. Renewable energy integration and energy storage
G. Regulatory process

Evaluation of pumped storage projects falls under Category F, which has a goal to "emphasize the critical role that hydropower can play in working to integrate other renewable technologies into the U.S. electric grid." Initiatives under this category include feasibility analysis of new pumped storage hydropower and assessment of energy storage needs.

In April 2012, the signatory agencies released a Two-Year Progress Report for the MOU that details progress on action items and future activities. The report is available at http://www.usbr.gov/power/hydropower-mou/HydropowerMOU.pdf.

1.1.2 State Renewable Portfolio Standards

Many states have implemented a Renewable Portfolio Standard (RPS) that mandates a certain percentage of all electricity sold in the state by a predetermined year comes from eligible renewable sources. Eligible renewable technologies vary by state, but generally include solar, wind, ocean wave, geothermal, biomass, landfill gas, fuel cells using renewable fuels, and small hydroelectric. All states within Reclamation's service area, except Idaho, Wyoming, and Nebraska, have either a RPS or RPS Goal. (If a RPS is identified as voluntary, it is referred to as a RPS Goal.) For the pumped storage projects evaluated in this Special Study, Montana and California have a RPS.

Montana's RPS requires public utilities and electricity suppliers serving 50 or more customers to obtain15 percent of their retail electricity sales from eligible renewable resources by 2015. In 2011, electricity suppliers provided 10 percent of retail sales from renewable resources, which was compliant with the interim 2011 RPS target of 10 percent (Montana Public Service Commission 2012).

California's RPS requires electric utilities to have 33 percent of their retail sales derived from eligible renewable energy resources in 2020 and all subsequent years. In 2012, California's three largest investor-owned utilities (Pacific Gas and Electric, San Diego Gas and Electric, and Southern California Edison) had served 19.8 percent of their retail electricity sales with renewable power (California Public Utilities Commission 2013).

Although Wyoming does not have a RPS, there is substantial renewable energy production from wind, solar, and geothermal resources. In 2009, the Bureau of Land Management (BLM) established the Wyoming Renewable Energy Coordination Office to facilitate development of renewable energy projects on BLM-administered public lands in Wyoming. Wyoming is also the location of the Chokecherry and Sierra Madre Wind Energy Project, which could include up to 1,000 wind turbines, making it the largest wind farm in North America (BLM 2012).

1.1.3 Pumped Storage Benefits and Ancillary Services

Pumped storage offers multiple benefits to a power system. In addition to providing energy storage, pumped storage can provide power immediately and can be rapidly adjusted to respond to changes in energy demands. These benefits are part of a large group of benefits, known as ancillary services. There are multiple ancillary services, with varying names and descriptions. The services evaluated in this study include the following.

Spinning Reserves – on-line reserve capacity that is synchronized to the grid and ready to meet electric demand within 10 minutes of a request. Spinning Reserve is needed to maintain system frequency stability during emergency operating conditions and unforeseen load swings.

Non-Spinning Reserves – off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a request, and that is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain system frequency stability during emergency conditions.

Frequency Regulation – on-line generation equipped with automated generation control that can respond rapidly, on a seconds to minute basis, to fluctuations in load. Regulation up is an increase in output and regulation down is a decrease in energy output in response to an automated signal.

1.2 Sites Identified for Study

Reclamation initially identified four existing sites for a potential pumped storage project based on existing infrastructure available. Each site includes two existing reservoirs, existing power complexes and infrastructure. The sites are described below.

1.2.1 Yellowtail Dam (Bighorn Lake) and Yellowtail Afterbay

Yellowtail Dam and Yellowtail Afterbay are in south-central Montana in Reclamation's Great Plains Region. Yellowtail Dam, constructed on Bighorn River, forms Bighorn Lake, which has a surface area of 17,300 acres, a length of 72 miles and a total capacity of approximately 1.3 million acre-feet. Yellowtail Powerplant, which lies at the toe of Yellowtail Dam, has an installed capacity of 250 megawatts (MW). The powerplant has been in operation since 1966. Yellowtail Afterbay Dam is 2.2 miles downstream from Yellowtail Dam. The dam forms Yellowtail Afterbay with a capacity of 3,140 acre-feet. Discharges are used to provide a uniform daily flow into Bighorn River, leveling the peaking power discharges from Yellowtail Powerplant.

1.2.2 Pathfinder Reservoir and Alcova Reservoir

Pathfinder and Alcova reservoirs are on the North Platte River, southwest of Casper, Wyoming, in Reclamation's Great Plains Region. Pathfinder Reservoir has a total capacity of 1.0 million acre-feet. The Freemont Canyon Powerplant, on the North Platte River at the head of Alcova Reservoir, generates power during water releases from Pathfinder Reservoir. Water is conveyed to the powerplant through a three-mile long tunnel. The powerplant has an installed capacity of 66.8 MW and began operations in 1960. Alcova Dam in 10 miles downstream of Pathfinder Dam and has a total capacity of 184,208 acre-feet. Alcova Powerplant generates power from releases at Alcova Dam. The powerplant has an installed capacity of 41.4 MW and began operations in 1955.

1.2.3 Seminoe Reservoir and Kortes Reservoir

Seminoe and Kortes reservoirs are on the North Platte River upstream of Pathfinder Reservoir in Wyoming in Reclamation's Great Plains Region. Seminoe Reservoir has a total capacity of 1.0 million acre-feet. Seminoe Powerplant is at the base of the dam and has an installed capacity of 51.75 MW. The initial year of operation for the powerplant was 1939. Kortes Reservoir is 2 miles downstream of Seminoe Dam and has a capacity of 4,765 acre-feet. Water released from Seminoe Dam to Pathfinder Reservoir passes through the Kortes Powerplant to generate power. The powerplant has an installed capacity of 36 MW and began operations in 1950.

1.2.4 Trinity Reservoir and Lewiston Reservoir

Trinity and Lewiston reservoirs are on the Trinity River in northern California in Reclamation's Mid-Pacific Region. Trinity Reservoir has a storage capacity of 2.4 million acre-feet. Trinity Powerplant is a peaking facility with an installed capacity of 140 MW. The powerplant began operations in 1964. Lewiston Dam is about 7 miles downstream of Trinity Dam and forms Lewiston Reservoir, which has a capacity of 14,660 acre-feet. Lewiston Powerplant is as the base of Lewiston Dam. The powerplant has an installed capacity of 250 kilowatts (kW) and began operations in 1964.

1.3 Special Study Overview and Objectives

This Special Study is a preliminary evaluation of potential pumped storage opportunities at the selected Reclamation facilities. The study evaluates conceptual design, operations, economic, and environmental features of a potential pumped storage project. Reclamation identified the four sites described above for evaluation and planned to do a more detailed analysis on two of the sites. Therefore, the study approach was divided into two evaluation phases. Phase 1 of the study involved a preliminary screening level analysis of the four sites to select sites for further study in a Phase 2 evaluation. Phase 2 of the study includes a more detailed evaluation of the selected sites.

After the Phase 1 evaluation, Reclamation chose to do a more detailed evaluation on three sites, rather than two sites; Yellowtail, Seminoe, and Trinity were the selected sites. The following sections further describe the two evaluation phases. The purpose of this report is to document the methods and results of the Phase 2 evaluation.

1.3.1 Phase 1 Evaluation Summary

The Phase 1 evaluation identified and screened potential pumped storage options for Yellowtail, Pathfinder, Seminoe, and Trinity sites. The analysis identified a total of 46 pumped storage options that used active storage within either the existing forebay and afterbay and/or construction of a new off-stream upper reservoir. All options included new pump or pump-generating sets and appurtenant facilities and equipment.

The project team screened the 46 options based on technical criteria including operating head/water conductor length ratio, pump-turbine operating range, reservoir depth, energy storage, resulting installed capacity, and dam volume. Based on the technical screening, 14 of the initial 46 options were carried forward for AACE Class 4 cost opinions, site layout, operations, economic, and environmental evaluations. Table 1-1 summarizes the 14 options.

Table 1-1. Summary of Options

Site	Option Number	Upper Reservoir	Lower Reservoir	Resulting Installed Capacity (MW)	Energy Storage (MWh)	Construction Cost (million $)	$/MW Installed Capacity (million $)	Cost Ranking ($/MW)
Yellowtail	5A	New Reservoir 5A	Bighorn Lake	1,660	16,601	$2,081	$1.25	1
Yellowtail	5B	New Reservoir 5B	Bighorn Lake	1,607	16,067	$2,141	$1.33	2
Trinity	5G2-A	New Reservoir 5G2-A	Trinity	1,024	10,245	$1,885	$1.84	3
Trinity	5F	New Reservoir 5F	Lewiston	615	1,112	$1,223	$1.99	4
Yellowtail	4YA-1	Bighorn Lake	Yellowtail Afterbay	112	1,123	$233	$2.07	5
Seminoe	5C	New Reservoir 5C	Seminoe	572	5,715	$1,235	$2.16	6
Pathfinder	5A1	New Reservoir 5A1	Pathfinder	575	5,745	$1,251	$2.18	7
Seminoe	5A2	New Reservoir 5A2	Seminoe	957	9,573	$1,765	$2.28	8
Trinity	4TL	Trinity	Lewiston	111	1,112	$256	$2.31	9
Pathfinder	5D	New Reservoir 5D	Alcova	708	7,082	$1,700	$2.40	10
Trinity	5A-B	New Reservoir 5A-B	Trinity	765	7,654	$1,862	$2.43	11
Yellowtail	4YA-2	Bighorn Lake	Yellowtail Afterbay	54	536	$133	$2.48	12
Seminoe	5D1	New Reservoir 5D1	Kortes	266	2,664	$664	$2.49	13
Seminoe	5A1	New Reservoir 5A1	Kortes	277	2,767	$860	$3.12	14

For the Phase 1 evaluation, the project team conducted a qualitative operations and environmental evaluation focused on identifying fatal flaws. Only one option – Yellowtail 4YA-1 – was screened out for a fatal flaw relative to water quality issues with drawing Yellowtail Afterbay down to an elevation below 3,183 feet. All the other options were considered operationally and environmentally viable, though not without challenges.

At the conclusion of the Phase 1 evaluation, the project team recommended moving forward with Yellowtail 5A/B and Trinity 5G2A options. These options had the lowest cost per MW installed capacity and fewer operational and environmental constraints relative to other options. California also has a developed ancillary services market, which would facilitate economic benefits of the Trinity site likely quicker than the Montana and Wyoming sites where an established market does not yet exist. Reclamation also chose to carry forward a Seminoe site because of the wind development potential in Wyoming and the need for bulk energy storage to integrate wind into the utility grid. Appendix A includes the Final Phase 1 Evaluation Report.

1.3.2 Phase 2 Objectives

The Phase 2 objective is to further develop the conceptual framework for a pumped storage project at the sites recommended in the Phase 1 evaluation. This includes more detailed preliminary design, operations, economic and environmental analyses of the selected pumped storage sites - Yellowtail 5A, Seminoe 5A2, Seminoe 5C, and Trinity 5G2A – to inform Reclamation if a pumped storage project is a technically and economically viable method to support renewable energy objectives. The Phase 2 Report is not at the feasibility study level. The Phase 2 evaluation was conducted to provide preliminary information to answer following questions for each of the identified sites.

- What is a technically viable configuration and size of a pumped storage project?
- What are the potential unit operating ranges to integrate intermittent renewable energy resources?
- What are the transmission limitations to deliver potential power output?
- How can a pumped storage project be operated to maximize revenues and renewable energy integration, and not affect Reclamation’s existing water supply and power commitments?
- Is the project economically viable based on energy arbitrage and ancillary services benefits relative to construction and annual operating and maintenance (O&M) costs?
- What type of energy market is needed to support a pumped storage project? What do the pricing structures for energy and ancillary services need to look like for pumped storage to be economically viable?
- How do varying hydrologic conditions and climate change affect project operations and revenues?
- What are the environmental and regulatory constraints at the proposed sites?

1.4 Report Organization

This Special Study is organized into the following volumes.

Volume 1 Phase 2 Report – includes the Executive Summary and Chapters 1 through 13 that provide detailed methods, results, and conclusions of the following analyses:

- Site Identification and Preliminary Sizing
- Geology and Seismicity Studies
- Pumped Storage Evaluation – Single-Speed versus Variable-Speed Technology
- Unit Refinement, Sizing, Capacity, and Energy Studies
- Conceptual Layout and Cost Evaluation Studies
- Transmission Evaluation Studies
- Cost Opinion and Project Schedules
- Operation Studies
- Economic Analysis
- Environmental and Permitting Evaluation

Volume 2 Phase 2 Report Figures – includes preliminary design drawings referred to in Volume 1.

Chapter 2
Site Identification and Preliminary Sizing

2.1 Preferred Site Locations and General Arrangements

For the Phase 1 evaluation, the project team evaluated potential pumped storage development sites at the existing Yellowtail Forebay-Yellowtail Afterbay, Pathfinder-Alcova, Seminoe-Kortes, and Trinity-Lewiston facilities. At the conclusion of this study, Reclamation selected the following concept sites to conduct a more definitive Phase 2 evaluation:

- Yellowtail 5A & 5B
- Seminoe 5A2
- Seminoe 5A3
- Seminoe 5C
- Trinity 5G2A

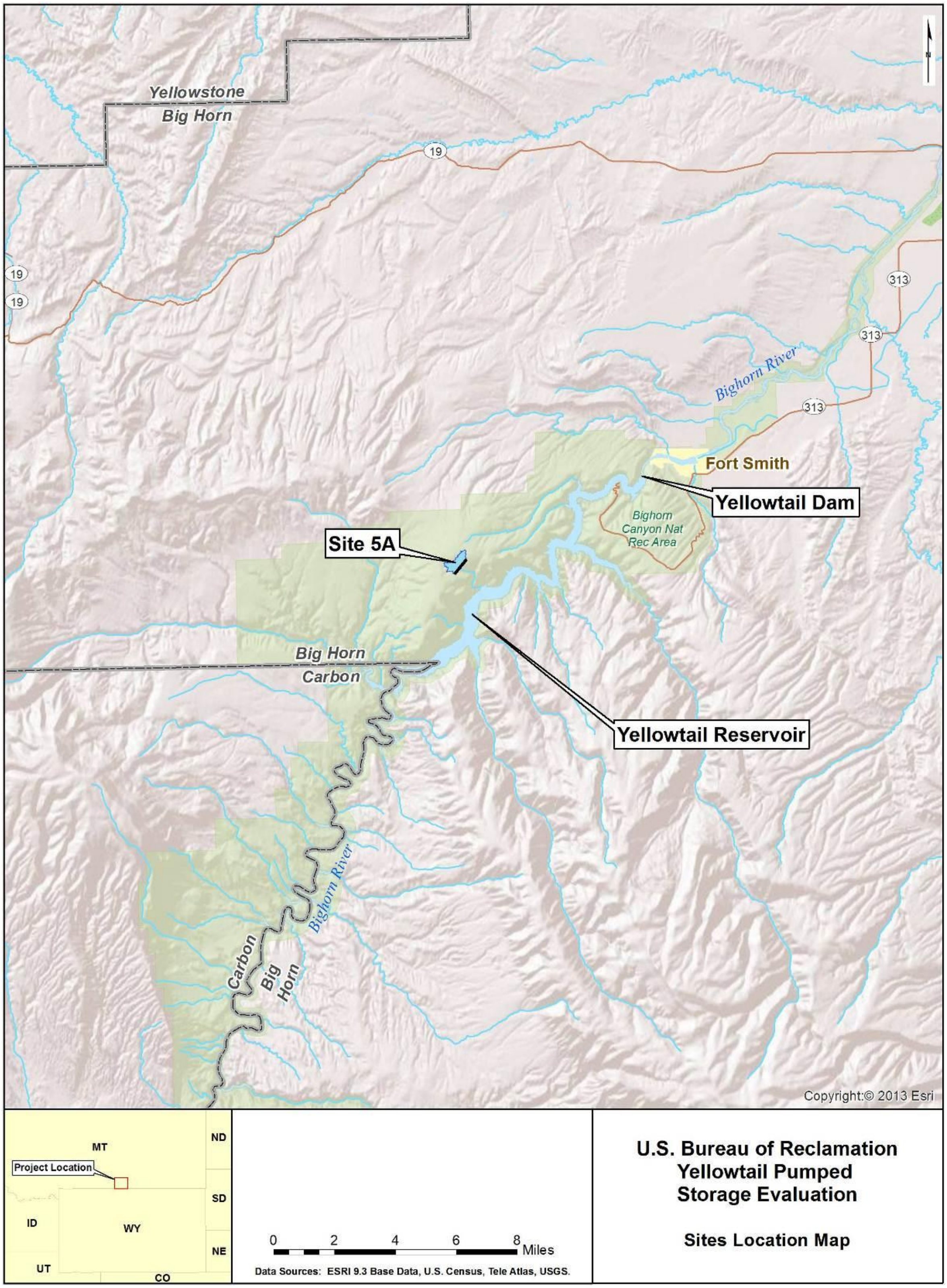
Listed below is a general description of each site. This chapter examines, evaluates, and refines the sites to select a preliminary configuration with which to perform conceptual layout studies, construction cost opinions, and economic evaluation.

2.1.1 Yellowtail 5A/B

The conceptual Yellowtail 5A/B pumped storage project is approximately 5 miles southwest of Fort Smith in south-central Montana in Reclamation's Great Plains Region (Figure 2-1). As currently configured, the Yellowtail pumped storage project would utilize the existing Bighorn Lake as the lower pool and a newly constructed upper reservoir. New features of the Yellowtail pumped storage project includes an upper reservoir, subsurface water conveyance system and below ground power complex, transmission lines, and other appurtenant facilities.

After preliminary engineering studies, Yellowtail Site 5A was selected for additional studies due to greater storage capacity, smaller embankment, and higher head relative to Yellowtail Site 5B.

Figure 2-1. Yellowtail 5A Pumped Storage Site Vicinity Map



2.1.2 Seminoe 5A2, 5A3 and 5C

The conceptual Seminoe pumped storage projects are located approximately 50 miles southwest of Casper, Wyoming in Reclamation's Great Plains Region (Figure 2-2). As currently configured, the Seminoe pumped storage projects would utilize the existing Seminoe Reservoir as the lower pool and a newly constructed upper reservoir. New features of the Seminoe pumped storage projects include an upper reservoir, subsurface water conveyance system and below ground power complex, transmission lines, and other appurtenant facilities.

After preliminary engineering studies, Sites 5A2, 5A3 and 5C were selected for additional studies due to greater storage capacity, embankment size, head, and cost per MW.

2.1.3 Trinity 5G2A

The conceptual Trinity pumped storage project is located approximately 40 miles northwest of Redding, California in Reclamation's Mid-Pacific Region (Figure 2-3). As currently configured, the Trinity pumped storage project would utilize the existing Trinity Lake as the lower pool and a newly constructed upper reservoir. New features of the Trinity pumped storage project includes an upper reservoir, subsurface water conveyance system and below ground power complex, transmission lines, and other appurtenant facilities.

2.2 Data Collection and Review

As part of this study, the project team collected and reviewed the following information for each project:

- Surrounding Topography (GIS)
- Top of Active Reservoir Storage (ft)
- Top of Inactive Reservoir Storage (ft)
- Active Reservoir Volume (ft)
- Dam Crest Elevation (ft)
- Installed Capacity (MW)
- Historical Lake Elevations (ft)

This information is summarized within project profiles in Figures 2-7 through 2-9 and historical lake elevations for each reservoir in Figures 2-10 through 2-12.

Figure 2-2. Seminoe 5A2, 5A3, and 5C Pumped Storage Site Vicinity Map

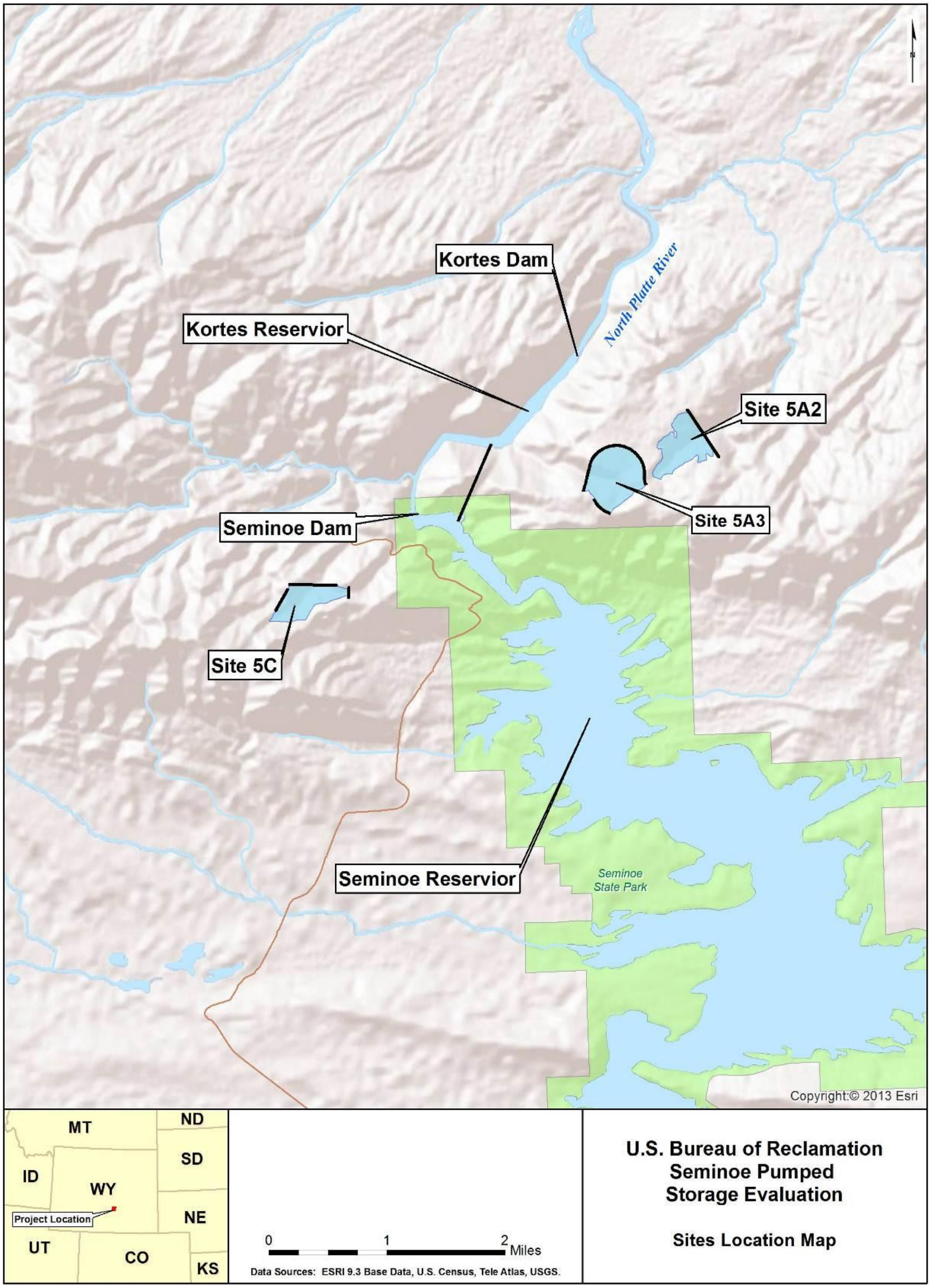


Figure 2-3. Trinity 5G2A Pumped Storage Site Vicinity Map

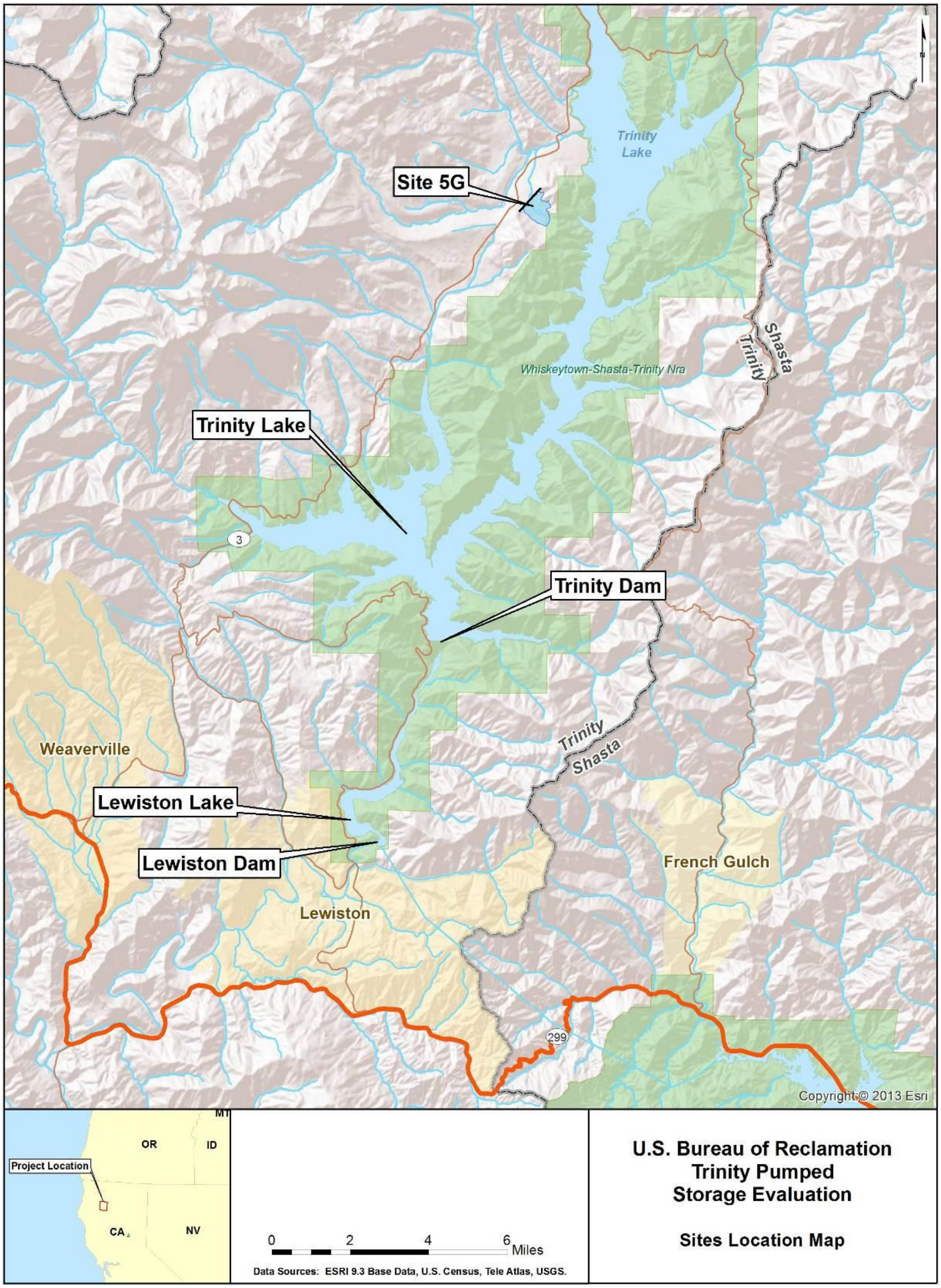


Figure 2-4. Yellowtail 5A Pumped Storage Site Configuration

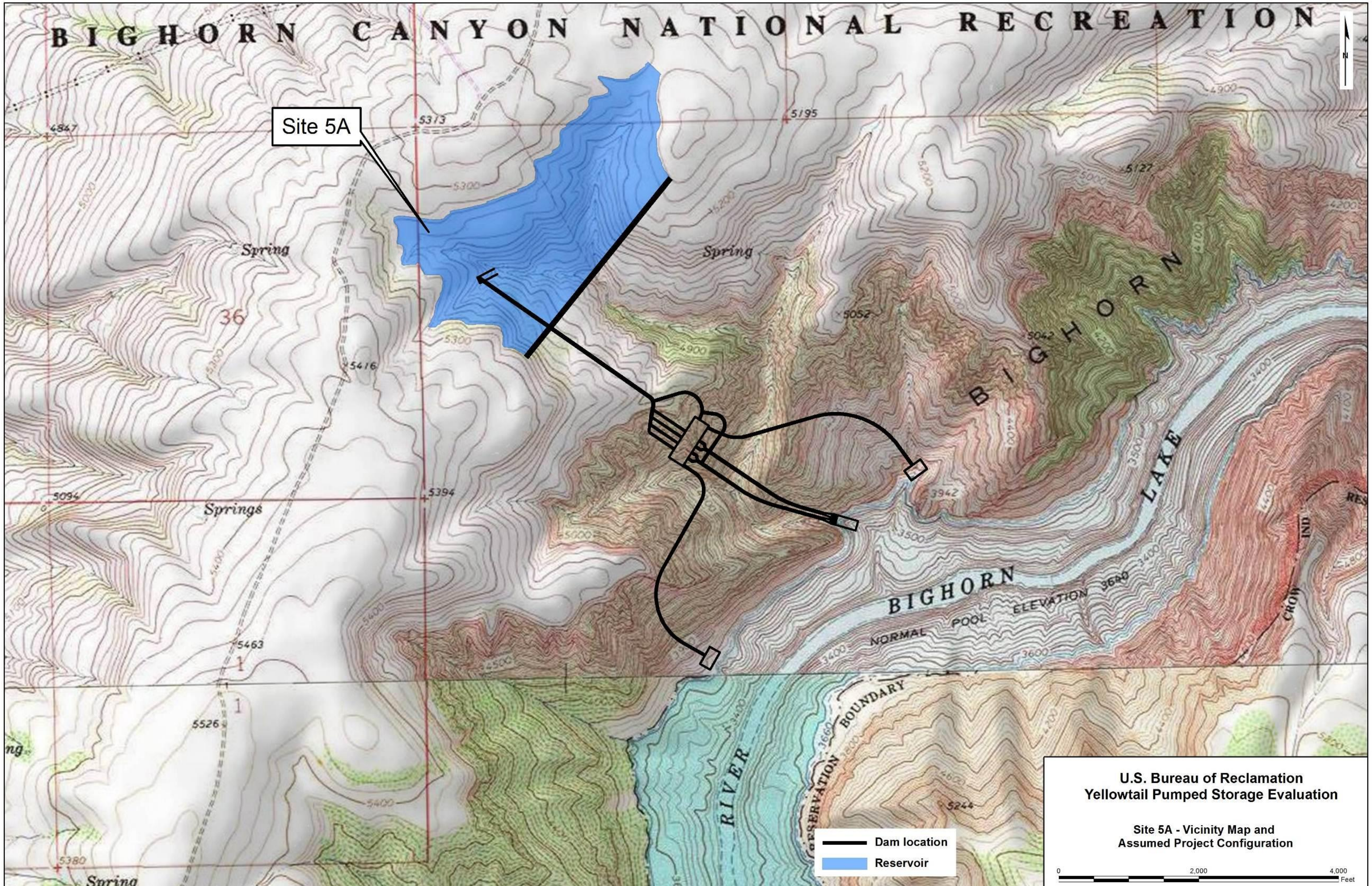


Figure 2-5. Seminoe 5A2, 5A3, and 5C Pumped Storage Site Configuration

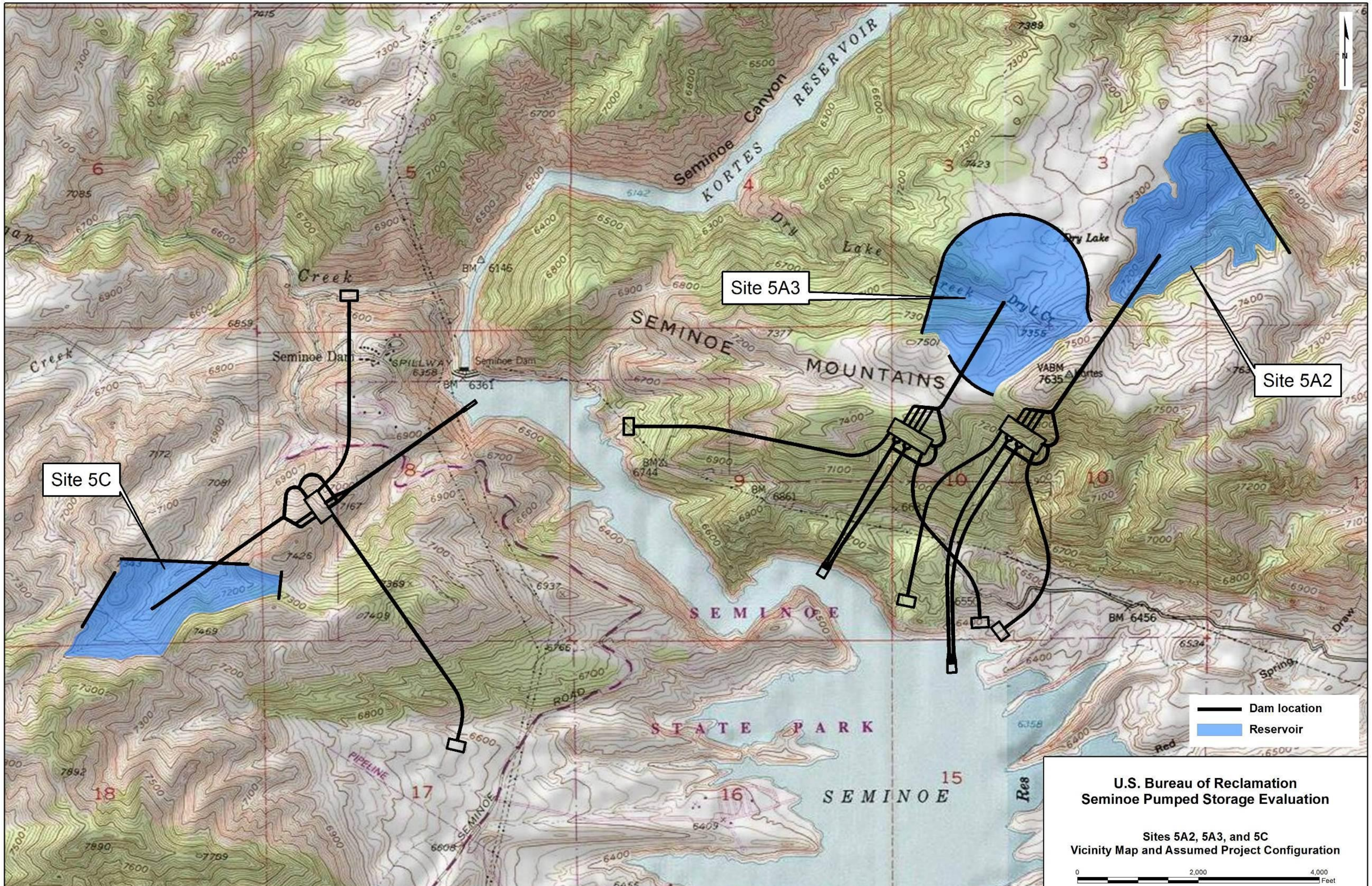


Figure 2-6. Trinity 5G2A Pumped Storage Site Configuration

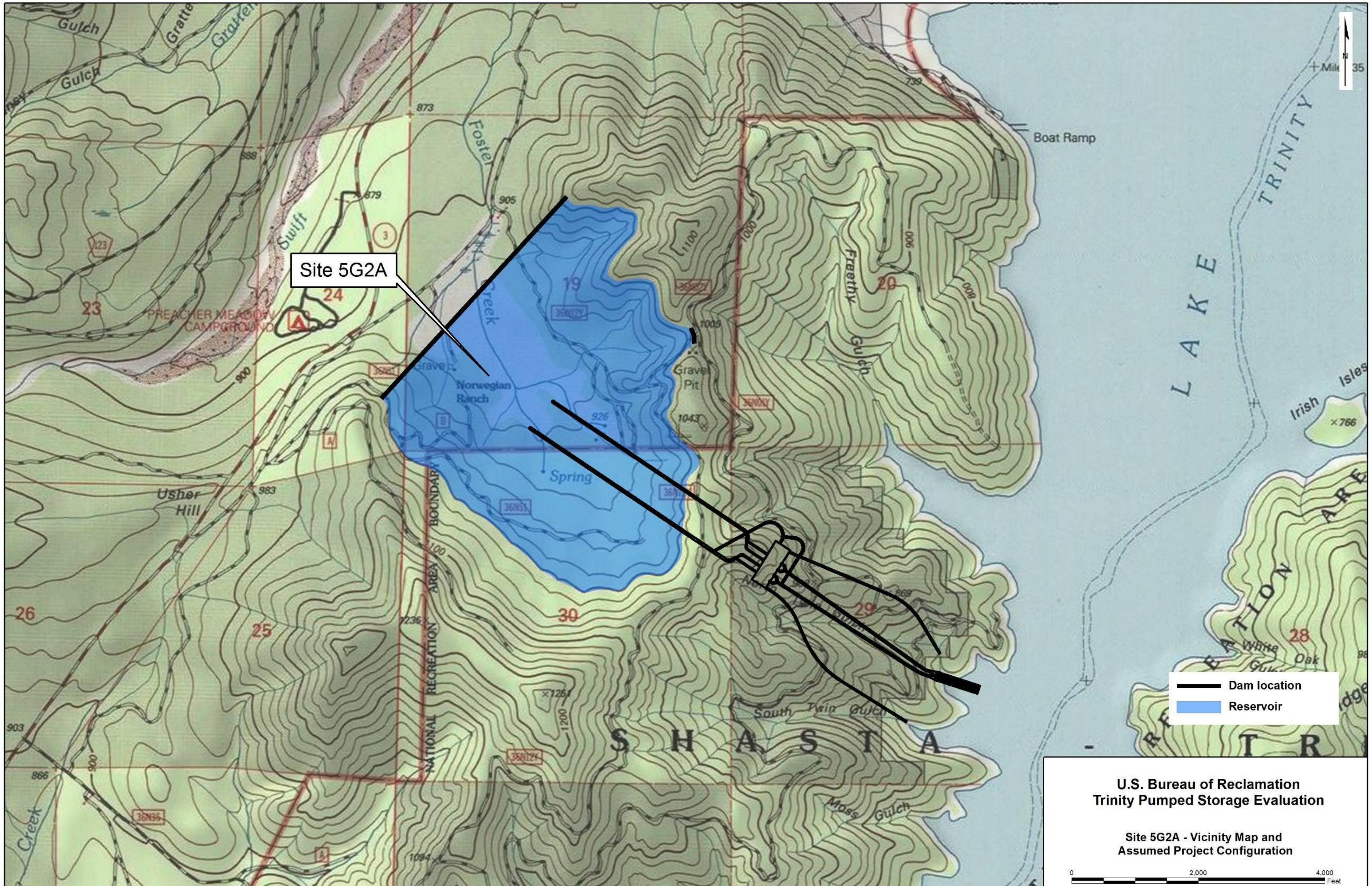


Figure 2-7. Yellowtail 5A Project Profile

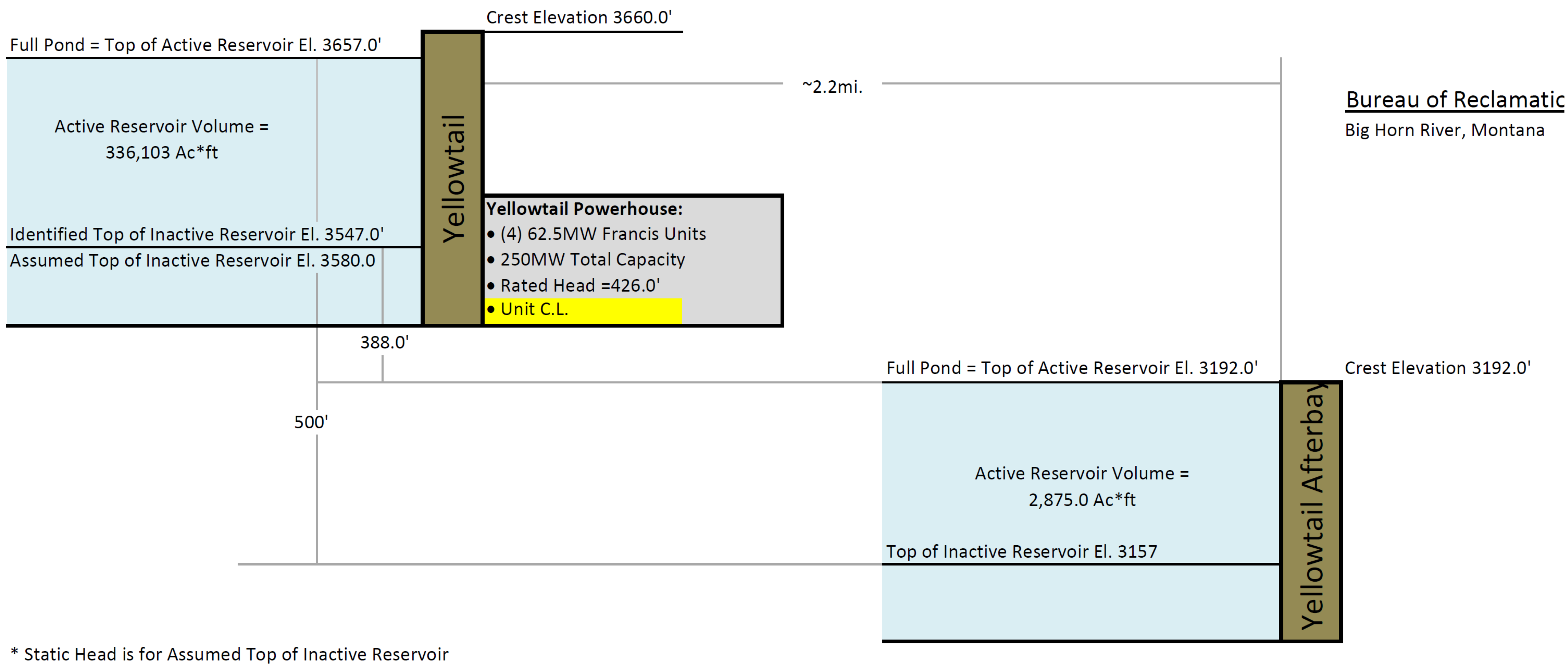


Figure 2-8. Seminoe 5A2, 5A3, and 5C Project Profile

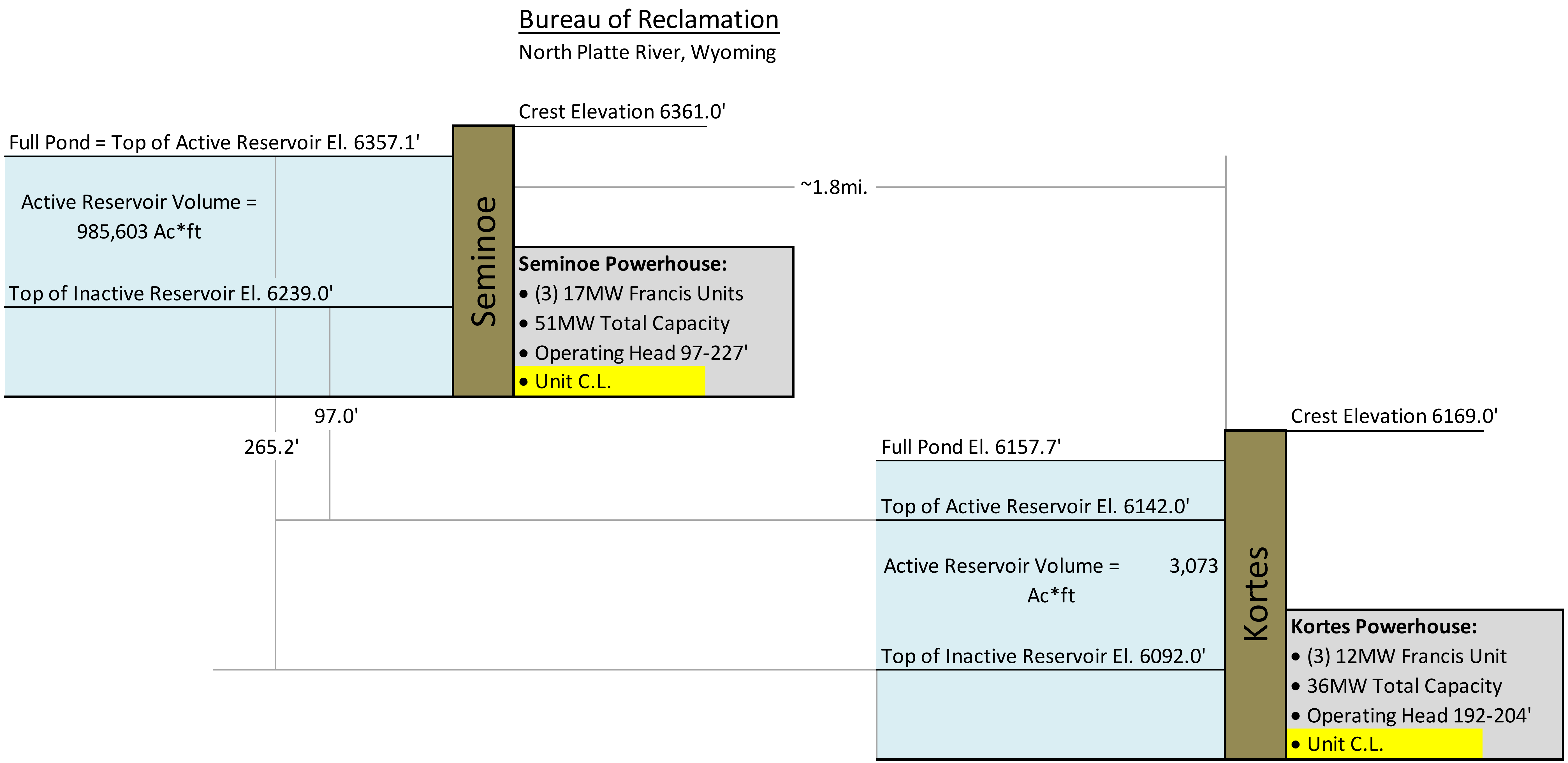


Figure 2-9. Trinity 5G2A Project Profile

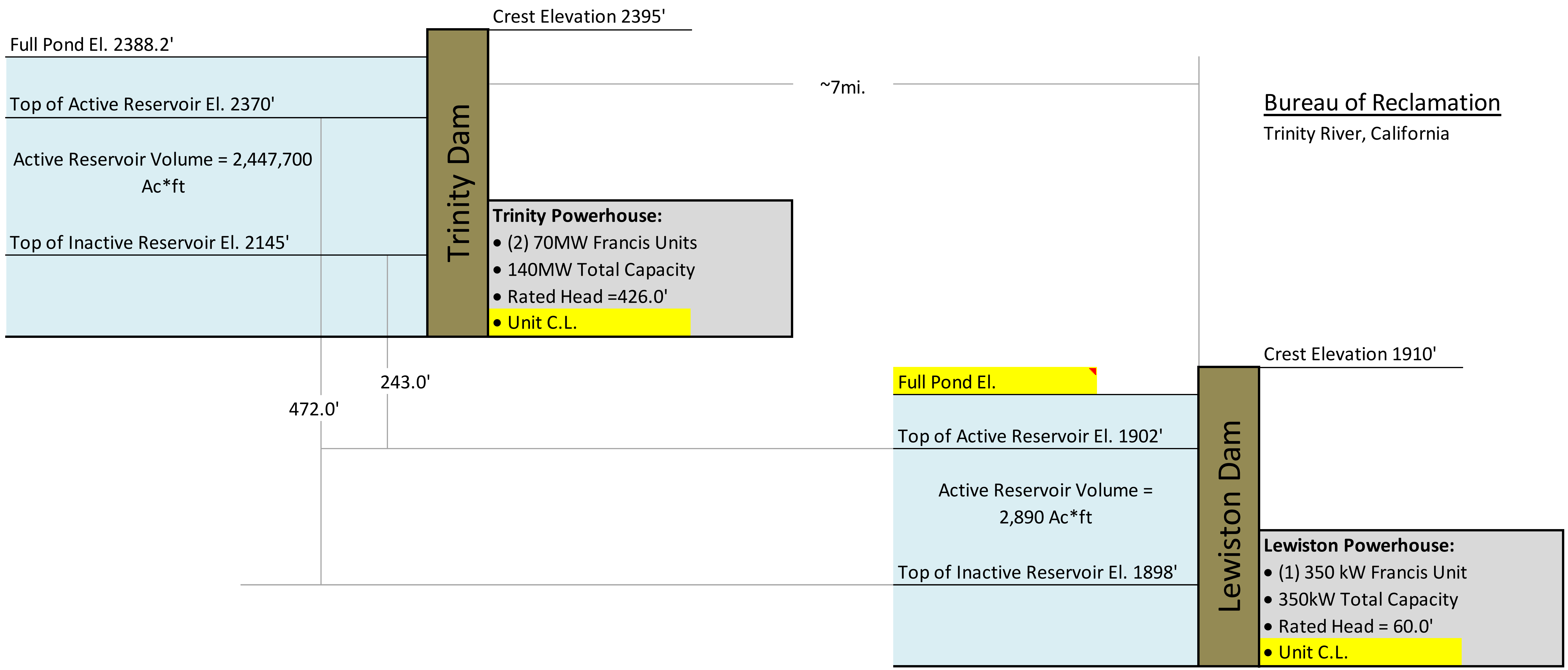


Figure 2-10. Yellowtail Historic Lake Level Elevations

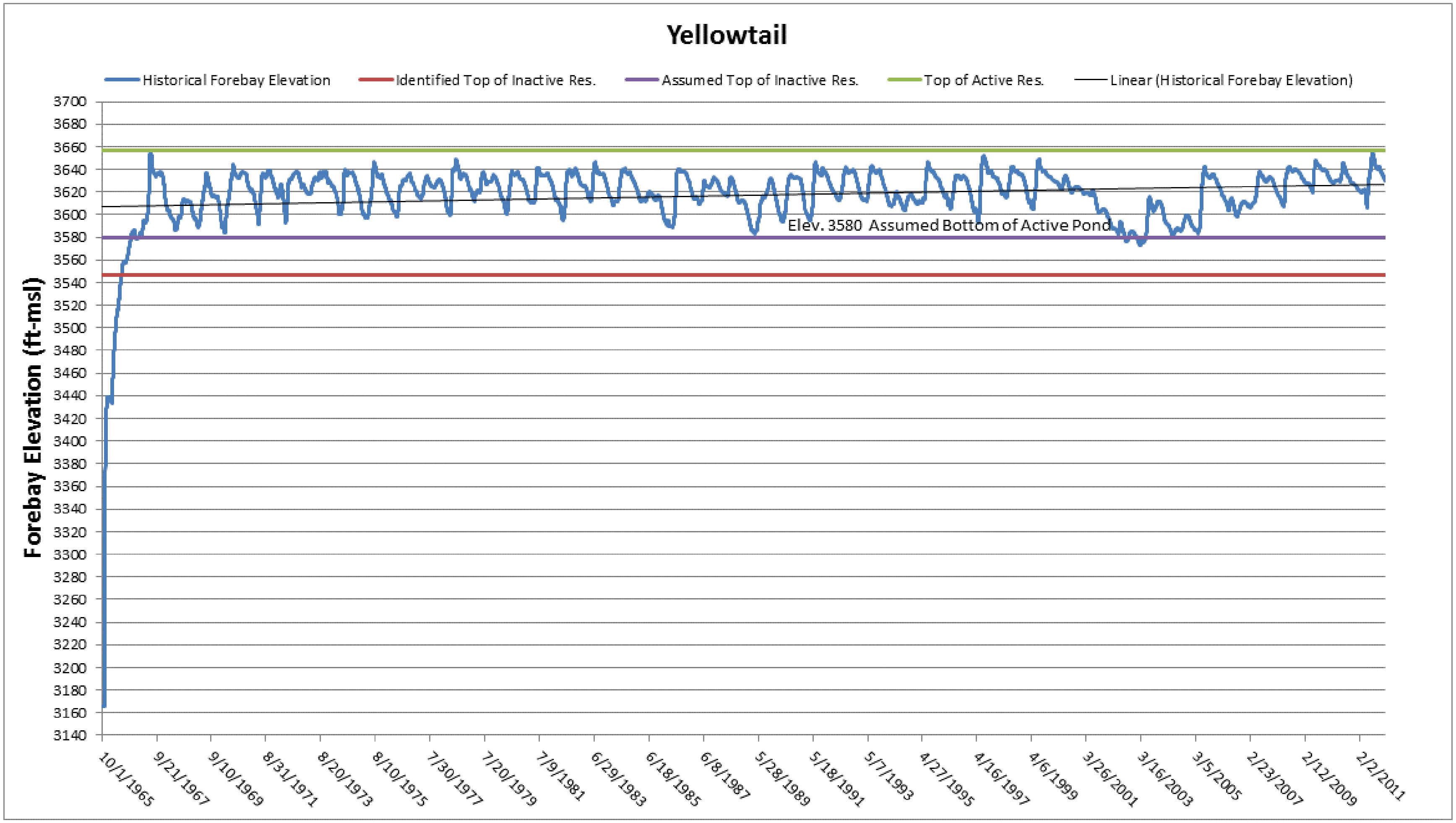


Figure 2-11. Seminoe Historic Lake Level Elevations

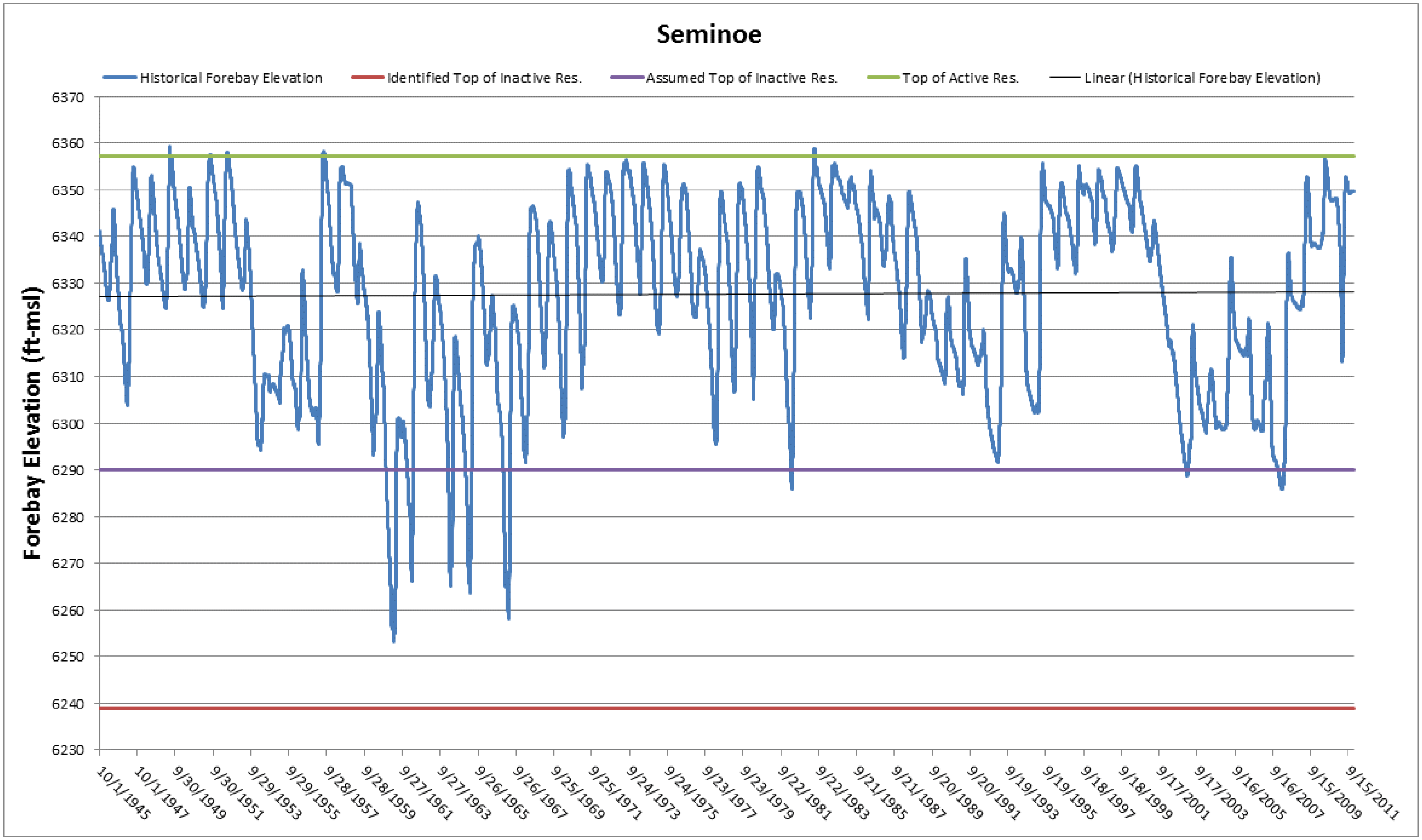
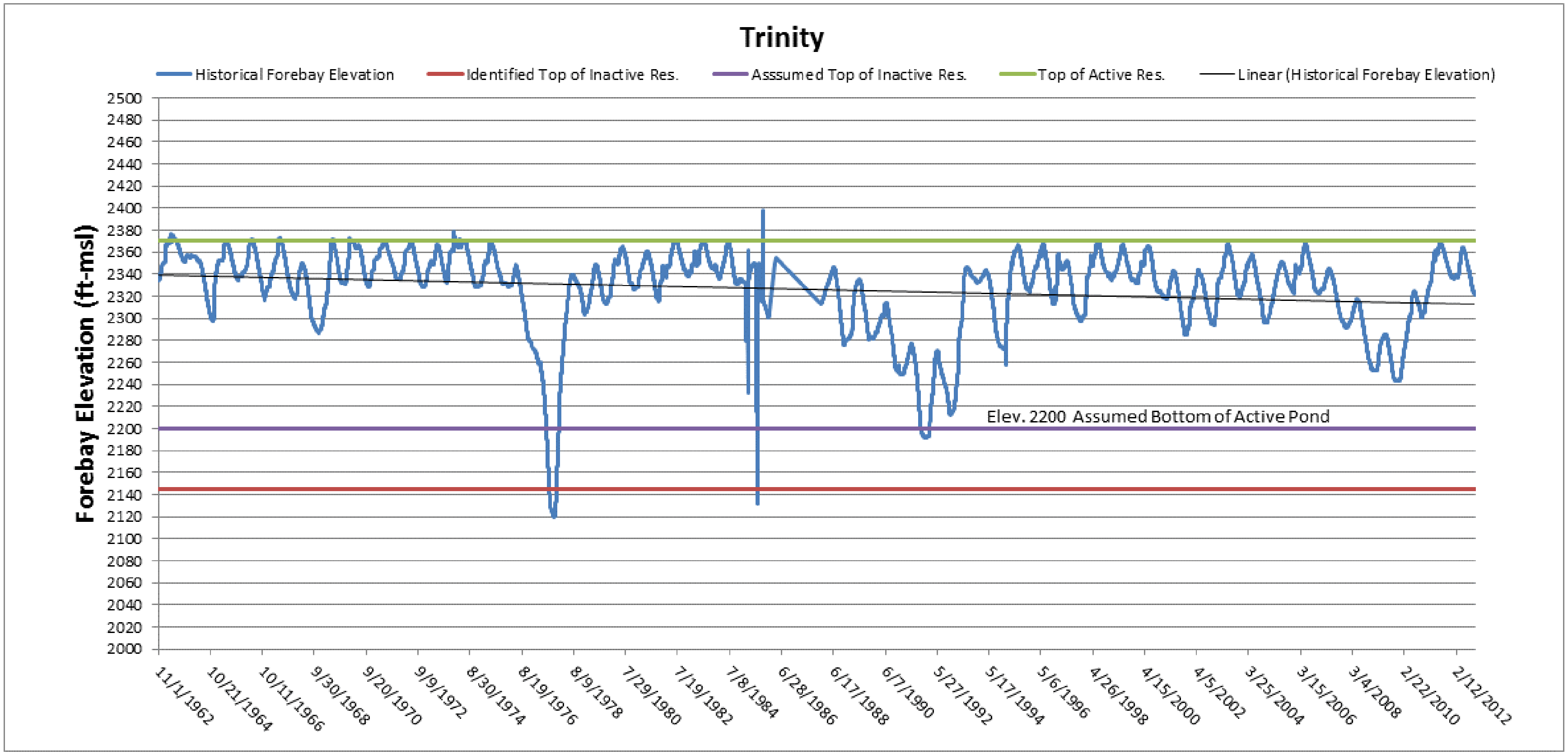


Figure 2-12. Trinity Historic Lake Level Elevations



2.3 General Configuration and Preliminary Sizing

2.3.1 Power Complex Configuration

The projects would have underground power complex configurations with the water conductors consisting of a headrace tunnel (vertical and horizontal), manifold tunnel, penstock tunnels, draft tube tunnels, and tailrace tunnels (Alternative A, as shown in Figure 2-13). In addition, the complex would have an underground transformer cavern with a low voltage bus tunnel extending to the surface. A separate powerhouse main access tunnel provides both construction and routine access into the powerhouse area. Construction adits are also shown and accounted for in layouts and cost opinions.

For each potential project site, the project team estimated the following characteristics, which are further described below.

- Embankment volumes
- Reservoir area-volume curves
- Drawdown characteristics and energy storage
- Installed capacities
- Generating discharge
- Water conveyance concepts

2.3.2 Embankment Volume Estimates

All dams would be rockfill concrete-faced and constructed with a crest width of 20 feet on slopes of 1.5H:1V with 10 feet of freeboard and 10 feet of foundation preparation. The maximum allowable dam height was approximately 400 feet.

2.3.3 Upper Reservoir Area-Volume

Upper reservoir area-volumes and drawdown were estimated from GIS-based digital topography (reference Figures 2-14 through 2-18).

Figure 2-13. Alternative Pumped Storage Project Profiles

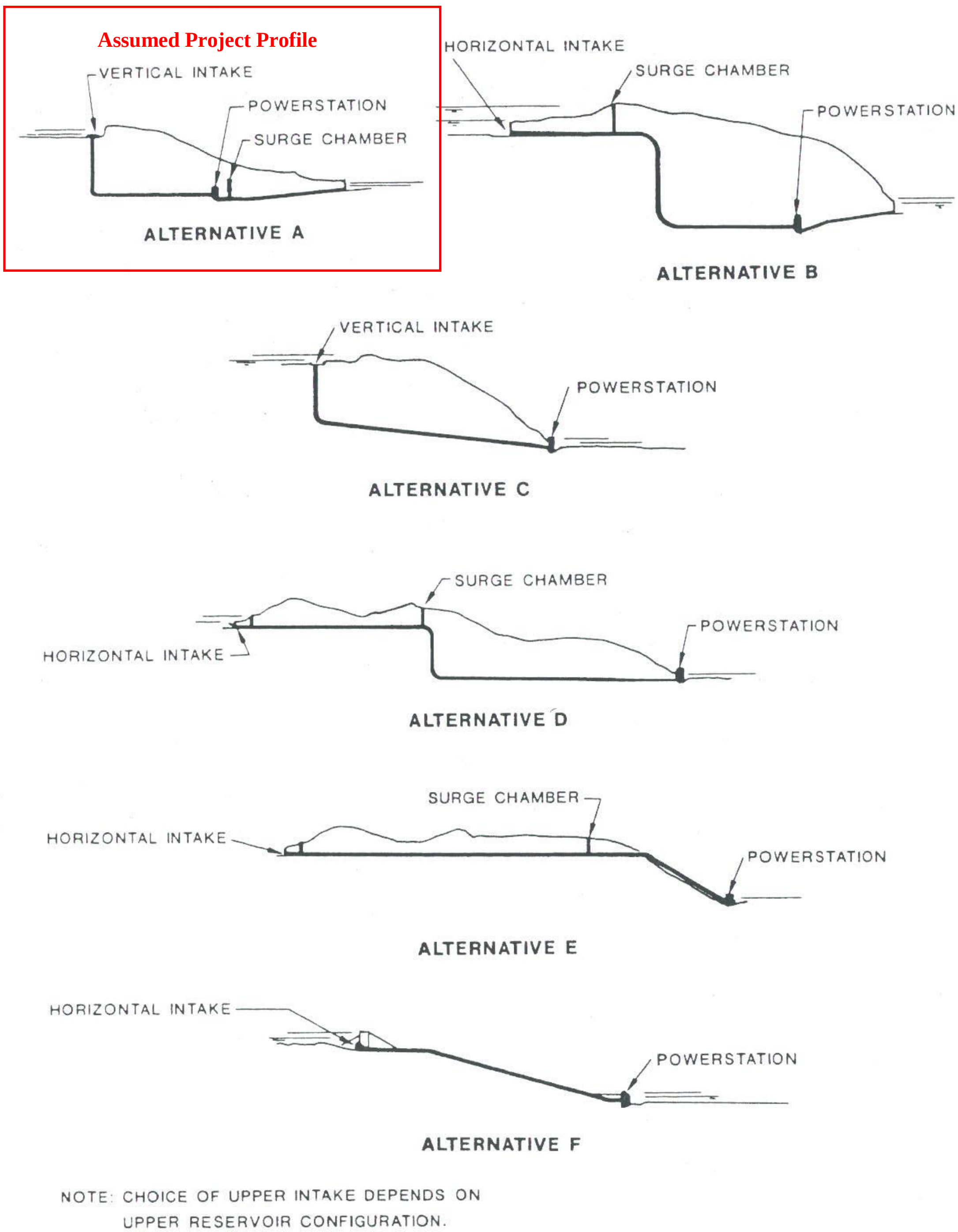


Figure 2-14. Yellowtail 5A Area-Volume Curve

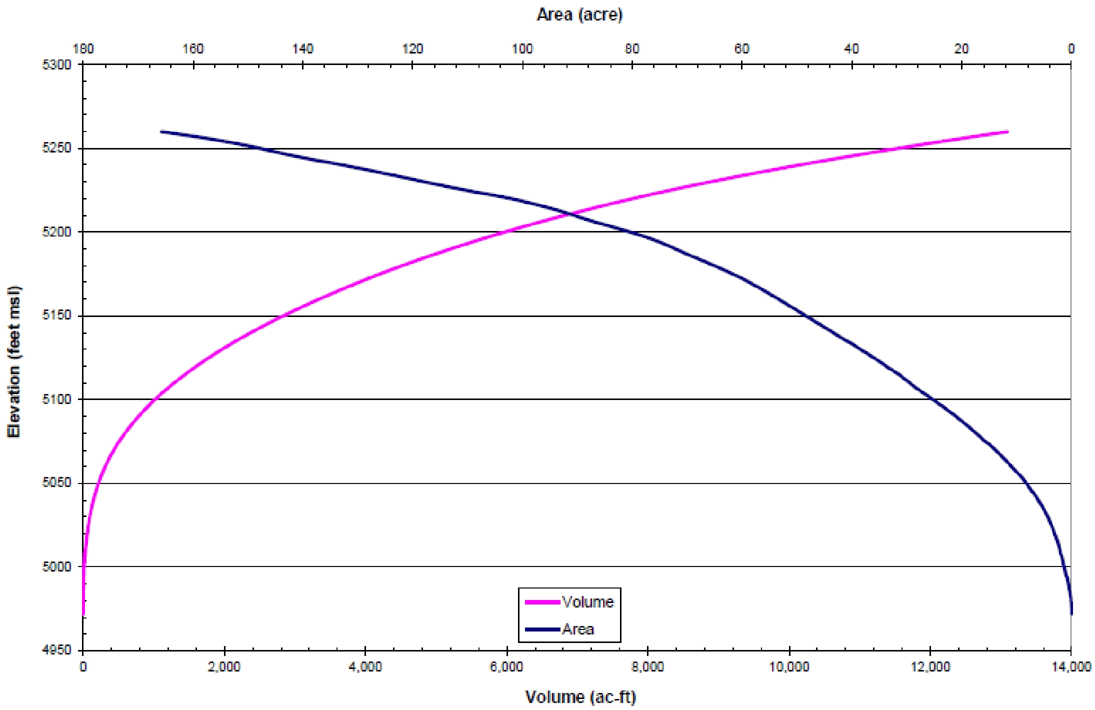


Figure 2-15. Seminoe 5A2 Area-Volume Curve

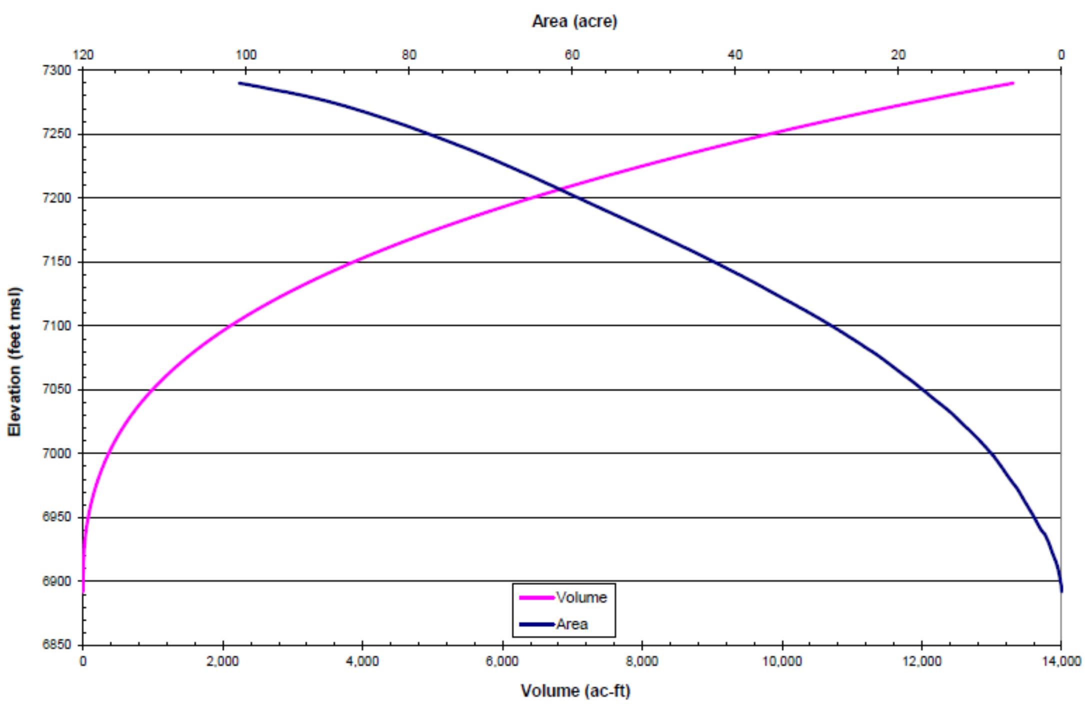


Figure 2-16. Seminoe 5A3 Area-Volume Curve

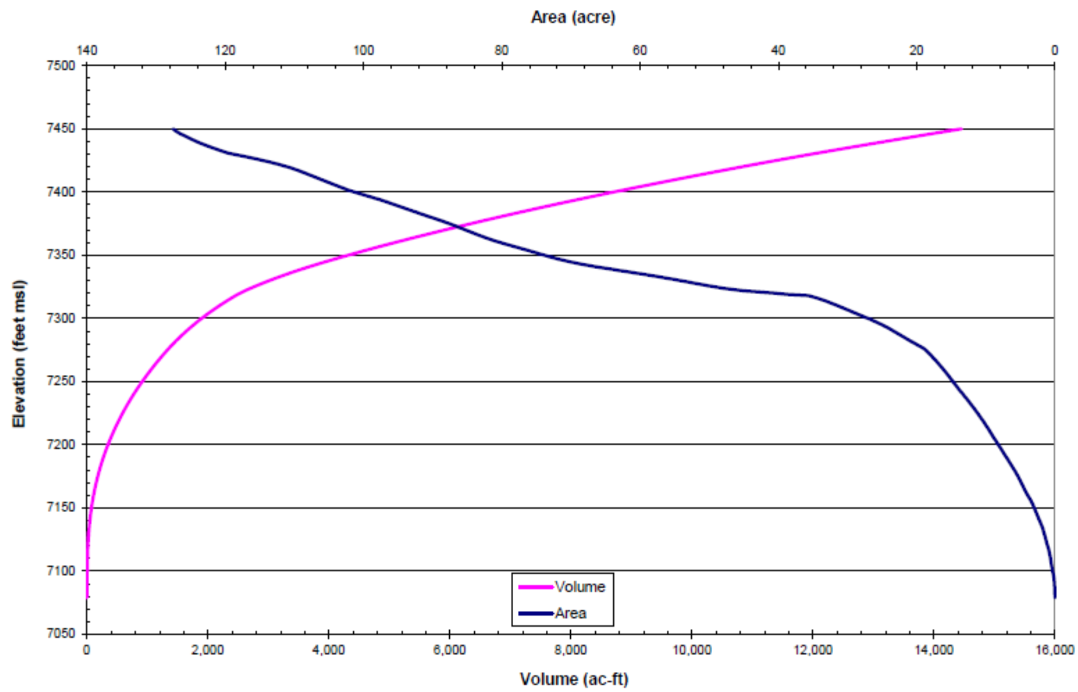


Figure 2-17. Seminoe 5C Area-Volume Curve

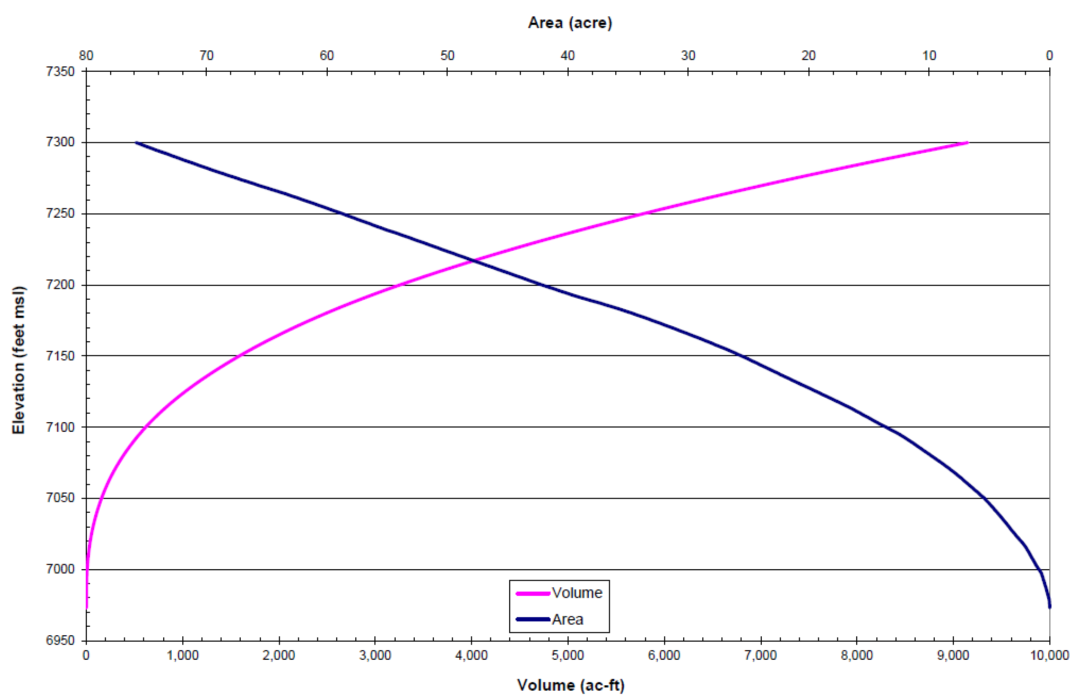
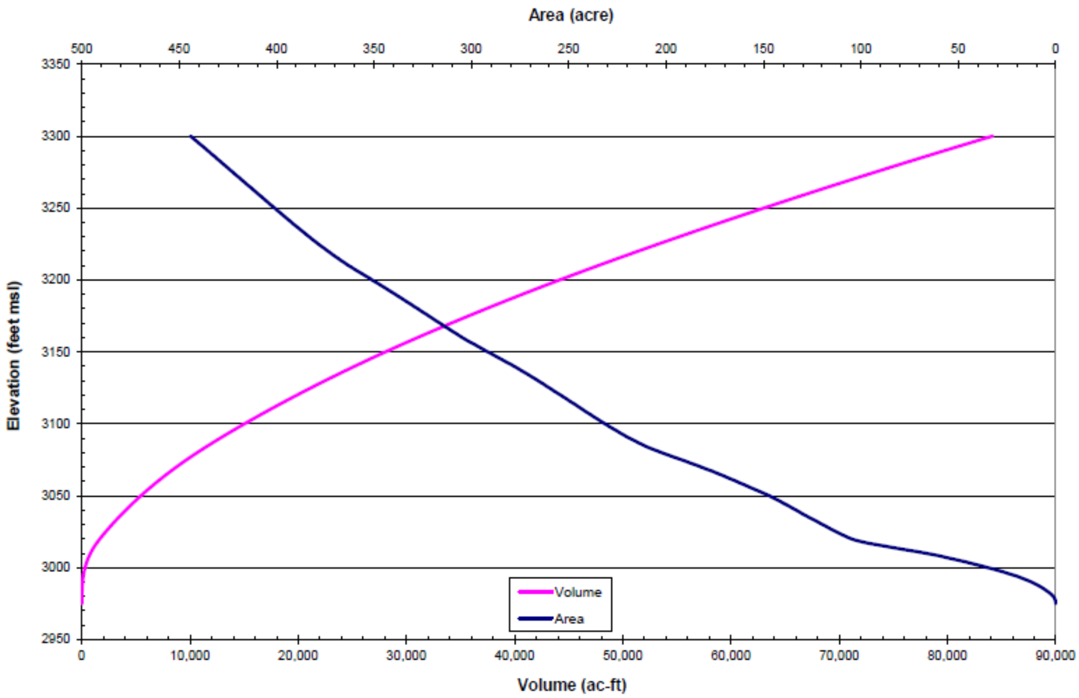


Figure 2-18. Trinity 5G2A Area-Volume Curve



2.3.4 Upper Reservoir Active Storage

Active storage was determined from available topography information and, where necessary, limited by a minimum to maximum gross head ratio of 70 percent reflecting variable-speed unit technology.

2.3.5 Upper Reservoir Energy Storage

Energy storage within the upper reservoir was estimated using the following relationship:

$$E = 0.88\ HS \times 10^{-3}$$

Where: E = Energy Storage (MWh)
H = Average Gross Head (ft)
S = Active Storage (acre-ft)

2.3.6 Capacity

Approximate generating capacity (MW) was estimated using the following relationship assuming 10 hours of storage reflecting a daily cycle for integrating intermittent renewable energy generation sources such as wind and solar:

$$C = E/\text{Hours of Storage}$$

Where: C = Rated Generating Capacity (MW)
E = Energy Storage (MWh)

2.3.7 Generating Discharge

The maximum generating discharge was estimated using the following equation:

$$Q = 11{,}800\ C/He = 13{,}720\ C/H$$

Where: Q = Design Discharge (cfs)
H = Average Gross Head (ft)
C = Rated Generating Capacity (MW)
e = Overall Generating Efficiency (assumed 0.86)

Table 2-1 contains a list of preliminary site characteristics for each proposed pumped storage project.

Table 2-1. Preliminary Site Characteristics

Assumed Feature (Conceptual)	Yellowtail 5A	Seminoe 5A2	Seminoe 5A3	Seminoe 5C	Trinity 5G2A
Max Upper Reservoir Elev (msl)	5,260	7,290	7,440	7,300	3,105
Min Upper Reservoir Elev (msl)	5,100	7,100	7,250	7,165	3,015
Estimated Dam Fill Volume (CY)	5,987,000	7,000,000	7,380,000	7,231,000	2,912,000
Max Lower Reservoir Elev (msl)	3,657	6,357	6,357	6,357	2,370
Min Lower Reservoir Elev (msl)	3,580	6,290	6,290	6,290	2,200
Upper Reservoir Drawdown (ft)	160	190	190	135	90
Min Head / Max Head Ratio (>.70)	0.86	0.74	0.78	0.80	0.71
Approx. Static Head (ft) (<2650 ft)	1,562	872	1,022	909	775
Maximum Dam Height (ft) (<400ft)	298	407	371	336	139
Required Submergence Below TW (ft)	270	205	205	180	130
Est. Conductor Length (L)	7,950	8,700	6,625	7,160	8,875
Conductor Length (L)/Static Head (H)	5.09	9.98	6.49	7.88	11.45
L/H General Acceptance Criteria	< 12	< 12	< 12	< 12	< 12
Upper Reservoir Usable Vol (acre-ft)	12,081	11,202	12,277	7,145	15,022
Lower Reservoir Usable Vol (acre-ft)	336,103	985,603	985,603	985,603	1,859,688
Energy Storage (MWh)	16,601	8,591	11,036	5,716	10,245
Assumed Hours of Storage	10	10	10	10	10
Resulting Installed Capacity (MW)	1,660	859	1,104	572	1,024

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Chapter 3
Geology and Seismicity Studies

3.1 Yellowtail 5A

3.1.1 Regional Geology

The Yellowtail 5A site is near the boundary of the Middle Rocky Mountains and Great Plains physiographic provinces in south-central Montana. The region contains a stratigraphic sequence, ranging in age from Cambrian to Miocene, deposited within and along the margins of the Bighorn Basin in northern Wyoming and southern Montana (Baars et al. 1988). The tectonic/depositional patterns of the Bighorn Basin are the result of folding and thrust-faulting that occurred in Late Cretaceous time and terminated during early Eocene time (Baars 1988). This pattern was superimposed on older, less intensive Paleozoic and Mesozoic events that were generally broad-scale gentile tilting, warping, and erosion (Baars et al. 1988). The Foreland Fold and Thrust Belt (Cordilleran Thrust Front) is west of the Bighorn Basin. In southwest Montana, this front has been overprinted by late Cenozoic faulting (Miller et al. 1992).

3.1.2 Site Geology

Figure 3-1 is a geologic map of the region. Yellowtail 5A site is underlain by sub-horizontal, bedded sedimentary rocks of Cambrian to Pennsylvanian age. From the youngest to oldest, these rocks are as follows (the bold initials refer to map designations on Figure 3-1):

lPt – TENSLEEP SANDSTONE (Pennsylvanian). A very light brown to very pale orange sandstone, fine-grained, well sorted, well rounded, and cross-bedded. Locally contains thin limestone beds and is cherty toward the top of the unit. In places, silicified to form quartzite. Thickness of the unit is about 200 feet.

lPMa – AMSDEN FORMATION (Lower Pennsylvanian-Upper Mississippian). Interbedded, grayish-pink to light red, mudstone, limestone (commonly cherty), and siltstone. The formation unconformably overlies the karst surface developed on limestone of the Madison Group and characteristically produces a pink stain on underlying cliffs of the Madison Group. It has a thickness from 140 to 300 feet, but is locally thinned to only a few feet along the margins of the Pryor Mountains uplift.

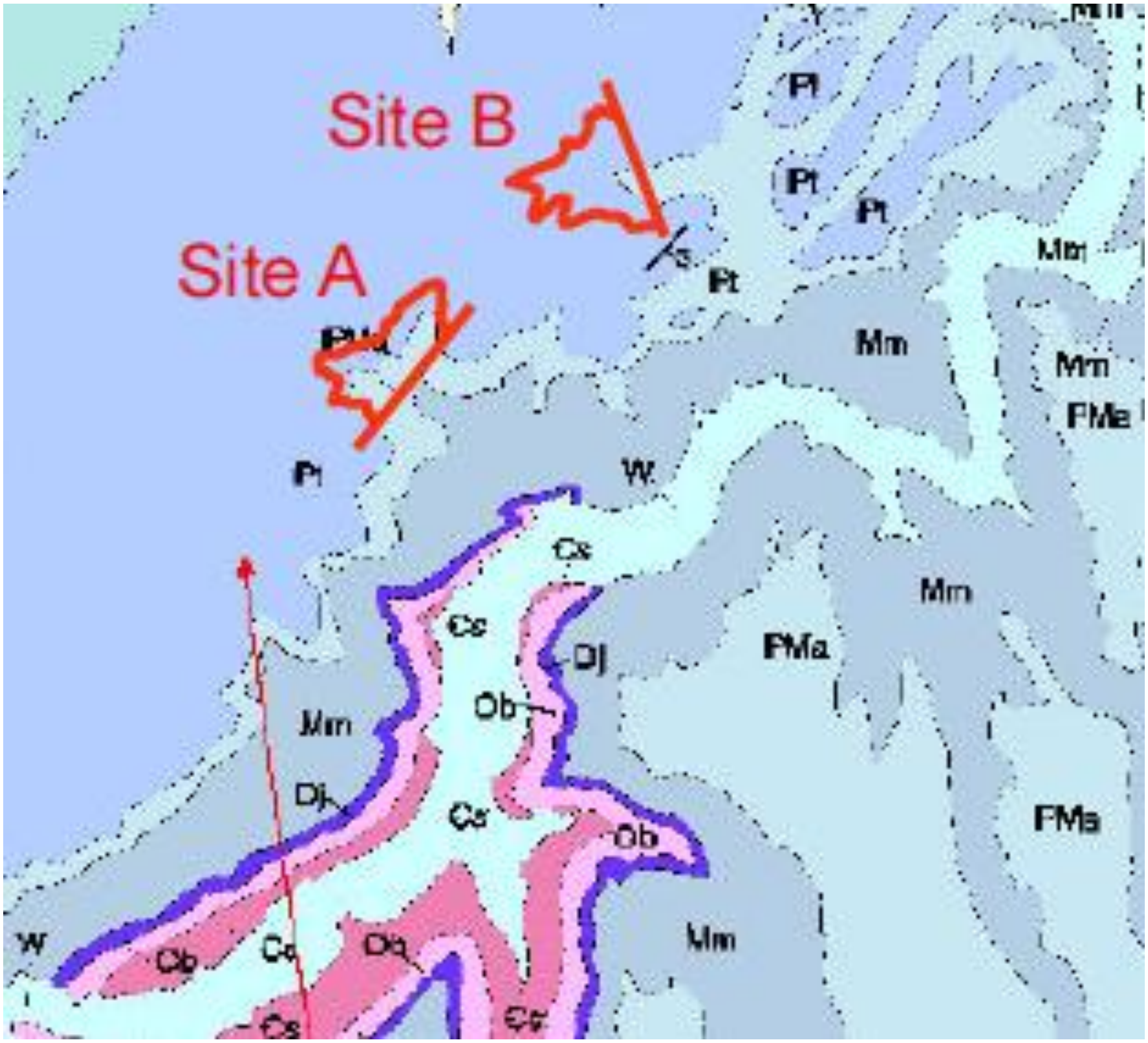
Mm – MADISON GROUP (Mississippian). Light gray to light brownish gray limestone and dolomitic limestone. Thick bedded to massive in the upper part (Mission Canyon Limestone) and thin-bedded to thick-bedded in the lower part (Lodgepole Limestone). Contains thin, interbedded gray shales and fossiliferous and cherty beds throughout the section. The upper section of the group has layers of gypsum and anhydrite. Collapse features and caves are common at the upper karst surface (Campbell 1978). The collapse features often contain pale-red breccias. Thickness is about 250 feet.

Dj – JEFFERSON FORMATION (Devonian). Light brownish gray dolomitic limestone. It is fetid, poorly exposed and typically occurs a float above the underlying Bighorn Dolomite. It is generally a stromatoporoid and coral-bearing dolomite, fossilerous limestone, evaporite beds, and shaly limestone; contains layers of highly porous dolomite. Thickness is about 250 feet.

Ob – BIGHORN DOLOMITE (Ordovician). Very light gray to very pale orange, dolomite and dolomitic limestone. Lower part of unit is fine- to coarsely- crystalline massive dolomite and thin- to thick-bedded dolomitic limestone in the upper part. The unit has a characteristic pock-marked surface due to differential weathering. It forms cliffs in the lower reaches of deep canyons. It has a thickness of about 500 feet.

Cs – CAMBRIAN SEDIMENTARY ROCKS UNDIVIDED. Light red sandstone and quartzite, greenish-gray shale and sandy shale, gray thin-bedded limestone, and greenish-gray, flat-pebble limestone conglomerate. Thickness is from 700 to 800 feet (Lopez 2000).

Figure 3-1. Geologic Map of the Vicinity of Yellowtail Sites 5A and 5B



Source: Lopez (2000)

Pryor and Big Horn Mountains were formed by vertical uplift and associated normal faulting. The Pryor Mountains consists of four major structural/ mountain blocks formed by a series of north-trending asymmetrical anticlines deformed by normal faulting. The northern end of the Big Horn Mountains is a north-plunging antiform with a broad top and steeply plunging limbs. The Bighorn River flows between the two mountain ranges and has formed a deep canyon as uplift took place.

More than 40 caves are present in the Pryor and Big Horn Mountains (Campbell 1978) and are located along the Big Horn and Carbon Counties border along Dry Head Creek and the Bighorn River. The principal cave-forming rock is the Mission Canyon Formation of the Madison Group. The formation consists of solution and collapse breccias in the upper 50 feet of the formation with most of the caves in the upper 100 feet. The solution breccias consist of dolomitic limestone fragments cemented by a calcareous siltstone and/or silty limestone and are thought to result from the leaching of evaporate layers in the formation when exposed to surface erosion and weathering (Campbell 1978). The collapse breccias are thought to be caused by the collapse of sinkholes and caves due to the formation of a karst terrane (paleo-karst) on top of the Madison Group that developed before the deposition of the Amsden Formation. Sink holes as deep as 200 feet, filled with limestone fragments and red clay (of the overlying Amsden Formation) have been found in the upper part of the Madison Group (Campbell 1978).

3.1.3 Regional and Local Seismicity

Western Montana has a large number of late-Quaternary Basin and Range normal faults with associated historical seismicity (Figures 3-2 and 3.3). This region includes the Intermountain Seismic Belt (ISB; Figure 3-2; corresponds to the Foreland Fold and Thrust Belt), the seismically and volcanically active Yellowstone region (YS; Figure 3-2), and the Centennial Tectonic Belt (CTB; Figure 3-2; Wong et al. 2005). The largest historical earthquake in Montana was the M 7.3 (moment magnitude) Hebgen Lake earthquake in 1959, located west of Yellowstone National Park (160 miles from the site; Figure 3-3). The next largest event occurred in 1925, the M 6.6 Clarkston event (175 miles from the site). The eastern half of Montana has a relatively low seismicity rate, similar to other portions of the Great Plains. The Yellowtail sites are within the Middle Rocky Mountains (MRM; Figure 3-2) regional seismic source zone.

The project sites are within an area of low seismicity (Figure 3-3). Within a 50-mile radius, no earthquakes with $M \geq 3$ have occurred. The Montana earthquake hazard maps (Wong et al. 2005) indicates a Peak Ground Acceleration (PGA-Horizontal) of less than 0.1g with a recurrence interval of 475 years (10% probability of exceedance in 50 years). The U.S. Geological Survey (USGS 2008) Seismic Hazard Maps indicates a PGA in the project area of 0.06g to 0.08g with a recurrence interval of 2,475 years (2 percent probability of exceedance in 50 years; USGS 2008).

Figure 3-2. Historical (1809-2001) Quaternary Faults and Regional Seismic Source Zones

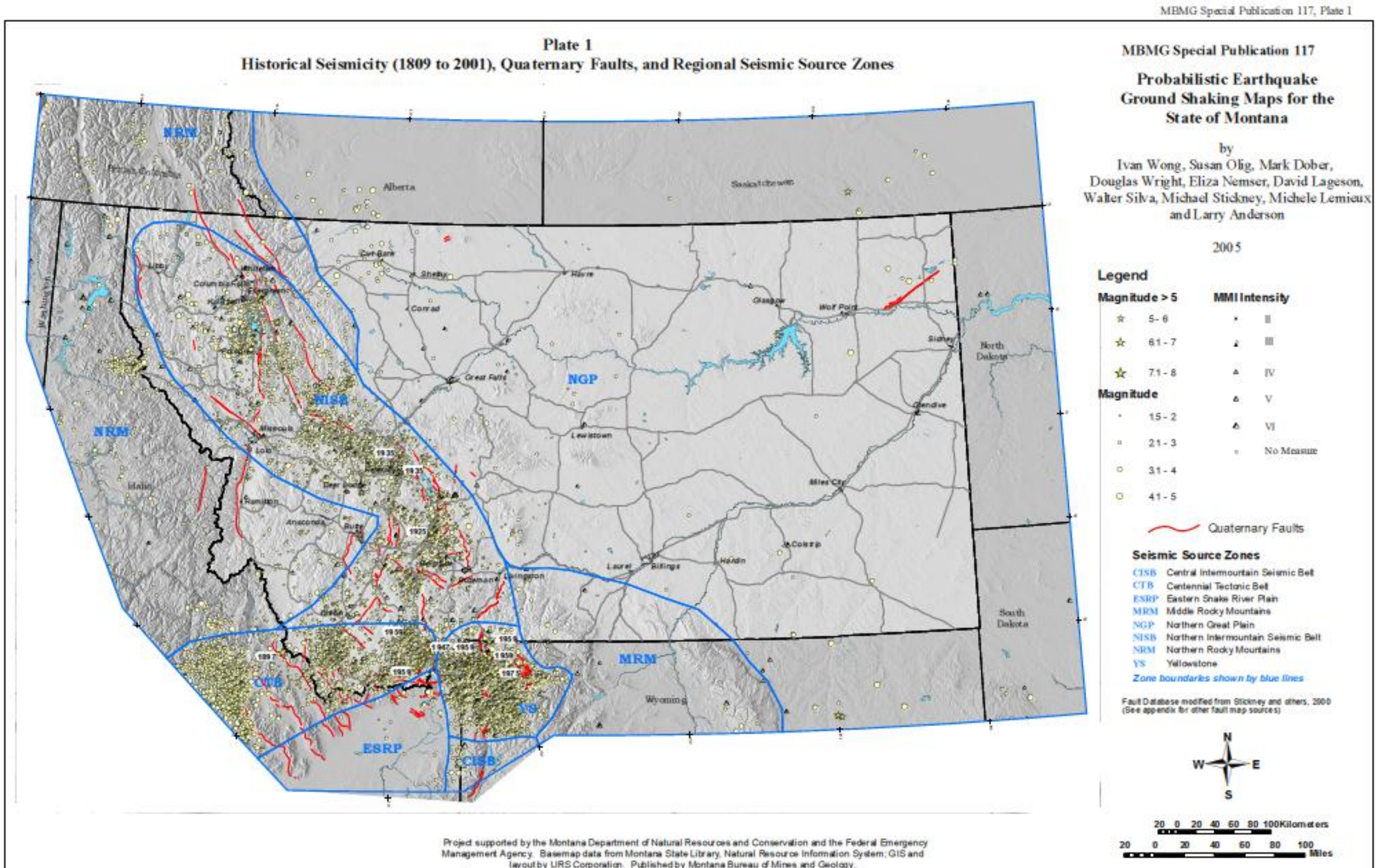
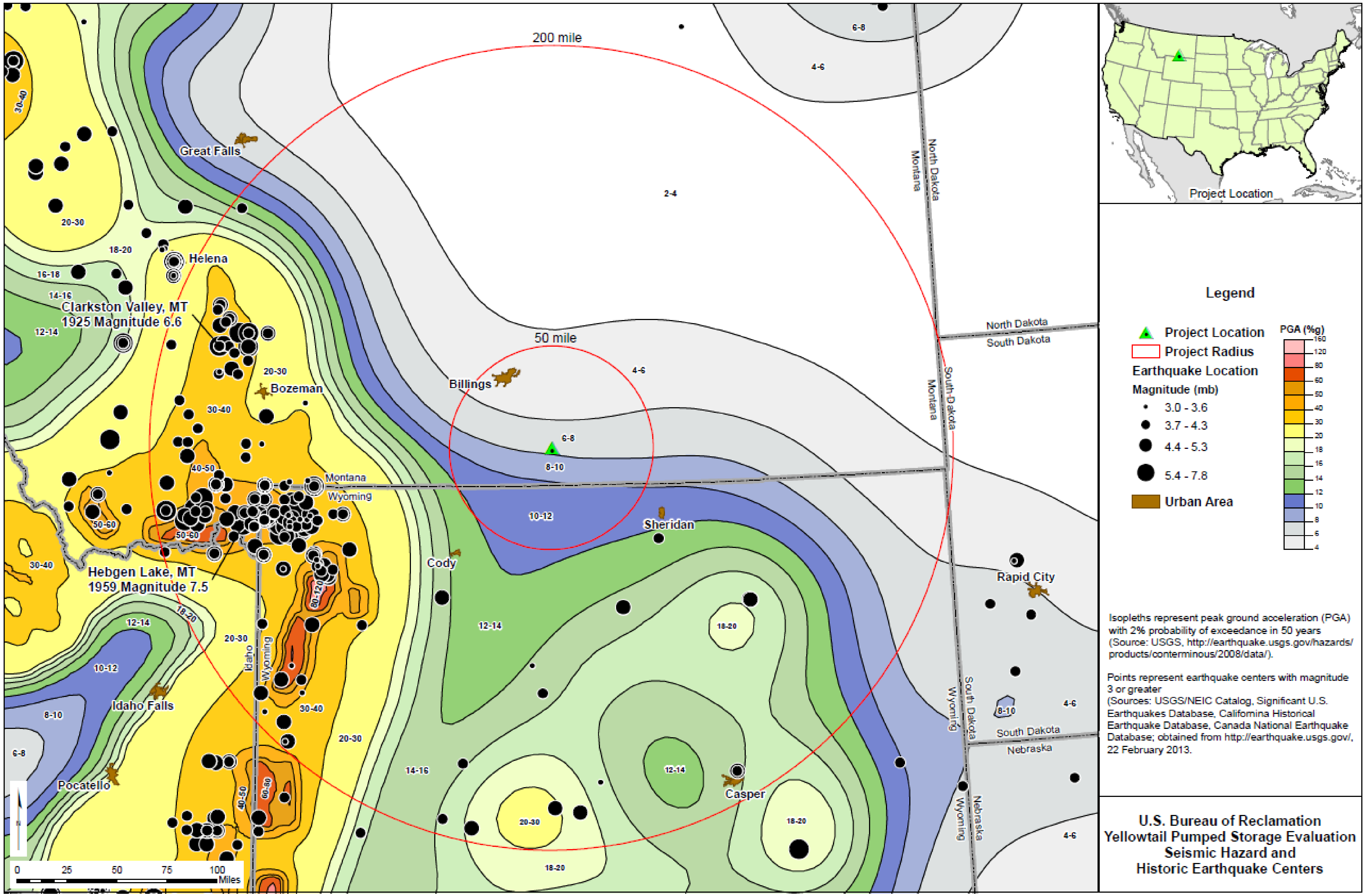


Figure 3-3. Yellowtail Pumped Storage Project Seismic Hazard and Historic Earthquake Centers



3.1.4 Evaluation of Geological Characteristics

This evaluation was based on a review of published maps and papers and relates this information, when possible, to the likely geological characteristics of the materials and bedrock underlying the two sites. The preliminary findings are summarized in Table 3-1. A detailed literature search and a geologic field reconnaissance was not performed as part of this study phase.

Table 3-1. Summary of Geologic Characteristics

Geological Characteristic	Relation to Project Areas
High seismic risk/active faulting within the Project area	The Project area is considered to have low to moderate seismic risk. No Quaternary faults in the site vicinities.
Active volcanism	Volcanic activity is present in Yellowstone National Park located west of the sites. Risk is considered low.
Active landslides in Project area	Current landslide activity is not known at this stage of the study for the Project sites.
Karst topography in reservoir area	Paleo-karst is highly likely in the Madison Group limestones underlying the reservoir area. A number of caves and collapse features are known to be present southwest of the two sites.
Groundwater conditions in reservoir areas presenting controllable/uncontrollable leaking potential	Not known at this stage of the study for the Project area. The groundwater conditions are likely to be complex based on the presence of the paleo-karstic terrane in the upper portion of the Madison Group limestones.
Deep chemical weathering profile	Soil thickness over the sedimentary rocks underlying Sites 5A and 5B not presently known.
Highly permeable rock	Present due to the presence of the paleo-karstic terrane on top of the Madison Group limestones and general karstic features of the area. Permeability of the Tensleep sandstones underlying the two reservoir sites are unknown; both porosity and fracture permeability. Other permeable rock may be present in the stratigraphic sequence through which the water conveyance tunnels would be placed.
Soluble rock material	Limestone, dolomitic limestone, dolomite, gypsum and anhydrite layers are present in the stratigraphic sequence underlying the dam sites and along the water and access tunnels.
Low strength, vibration-sensitive, friable, highly abrasive, slaking, or unlithified rock material	The strength of the Tensleep sandstone and of the underlying Amsden Formation mudstones, limestones are unknown at this time. The strength of the dolomitic limestone in the Jefferson Formation is unknown (would be present in water conveyance structures), but poor exposure of the unit in canyon walls suggest low strength and/or poorly lithified rock.
Highly faulted, folded, or fractured rock material	Based on the available geologic mapping, highly faulted and folded rock is not present in the site vicinities. Presence of fractured rock material is not known at this time.
Thinly laminated, structurally deformed, fine-grained rock masses	Thinly laminated, fine-grained rock masses are present in the site vicinities (Tensleep Sandstone and Amsden Formation) although not likely structurally deformed.
Stress-relieved reservoir rims	Not known at this stage of the study for the Project site.
Soils conducive to liquefaction	Soil deposits in the Project site will generally have very low to low liquefaction susceptibility.

3.1.5 Constructability

The dam and water conveyance systems, access tunnels, and powerhouse, would be constructed on/in rocks of above described sedimentary sequence. Potential dam foundation issues are:

- Mixed rock types in the dam foundations could result in the differential settlement of the dam structure.
- Cementation of the Tensleep Sandstone is not know at this time; hard, cemented sandstone make suitable foundations, but tend to be fractured allowing movement of water through the dam foundation.
- Weak seams and clay seams may be present in the foundations.
- The limestone underlying part of the Site 5A dam foundation and underlying both dam and reservoir sites may have existing caves and cavities underlying the dams and could collapse after the reservoir is placed in service.
- Chance of developing new sink holes is possible and will need to be considered.
- The impoundment of the reservoir can lead to discovery of channels missed during exploration.
- Washing out of cavity and fissure fillings by the new underground flow regime established by the impoundment.
- Dissolution of limestones, gypsum, and anhydrite can lead to severe problems involving potential leakage and ground collapse during reservoir operation (Goodman 1993). Extensive measures to control leakage in the bedrock underlying the dam sites would likely be required.

Potential reservoir issues include:

- The porosity of the Tensleep Sandstone is not known at this time. Pervious sandstone in the rim and underlying the reservoir may store a significant volume of water as bank storage and could have excessive water movement through the dam foundation.
- The fracturing of the Tensleep Sandstone is not known, but if present could result in leakage from the reservoir into the underlying paleo-karst of the Madison Group limestones. Either or both of these conditions could lead to a reservoir that does not hold water. A reservoir liner may be required.

Potential issues related to the construction of the water vertical shaft, water tunnels, and access tunnels and underground powerhouse are:

- Underground construction in karstic terranes (and limestones in general) can lead to sudden inflows of water, unstable tunnel faces and roof/crown conditions in clay and weathered rock, and block slides along bedding planes with mud/clay seams.
- Dissolution of gypsum and anhydrite layers can lead to unstable and variable structures including breccia pipes, disturbed bedding, and voids.
- Low strength of gypsum layers can result in squeezing in tunnels.
- Water tunnels passing through gypsum must be free of leakage since solution would create unstable conditions.
- Leakage into anhydrite layers would result in hydration to gypsum resulting in expansion and potential high pressures on tunnel linings.
- Potential strength and stability issues related to thinly interbedded mudstone, siltstone, sandstone, shale, and sandy shale that will be encountered in the underground structures (Goodman 1993).

Some of these are significant challenges to construction; however, all these potential problems can be remediated with an associated cost.

The availability of suitable materials for dam construction is not known at this phase of the study and will require additional site characterization studies. Depending on the condition of the Tensleep sandstones, it may be useable for rock fill for a concrete-faced rockfill dam. If the sandstone is friable, its use is limited by the potential for deterioration in the rock fill. A harder, well-cemented sandstone makes satisfactory rock fill. As an aggregate in concrete, sandstone can be used, but in mass concrete where control of thermal stresses is critical, they are found to produce larger thermal stresses than other aggregates (Goodman 1993). Limestone and dolomite of the Madison Group may be usable for aggregate as long as argillaceous (shale layers) material is removed. The Tensleep Sandstone and Madison Group limestones include cherty horizons and layers. Chert can react with alkalis of the cement causing destructive cracking and expansion of the concrete and would have to be controlled in the quarrying operation for aggregate.

3.1.6 Conclusions

No fatal flaws related to geology and seismology were identified during this preliminary desktop study. However, a number of serious and potentially costly geologic issues were identified that will need to be addressed in detail in the next phase of site characterization study.

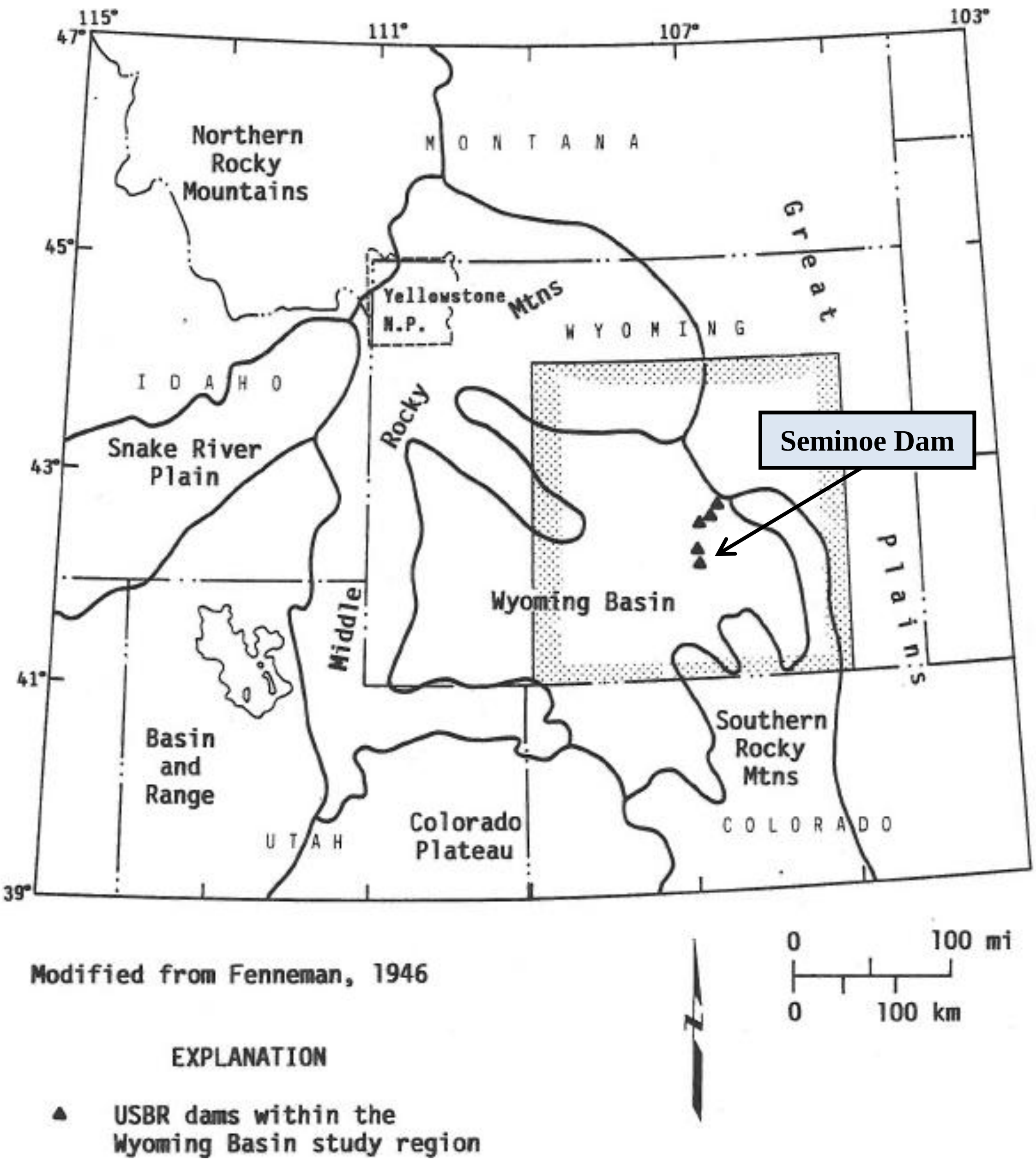
3.2 Seminoe 5A2, 5A3, and 5C

3.2.1 Regional Geology

The proposed Seminoe 5A2, 5A3, and 5C pumped storage sites are in the Wyoming Basin physiographic province (Figure 3-4). The Precambrian geologic Wyoming Province, that underlies the basin and much of Wyoming and portions of the surrounding states, is an Archean age (>2.7 Ga) craton that consists of granitic gneiss with interspersed greenstone belts that are exposed in the cores of several Laramide uplifts/mountain ranges in Wyoming (Houston and others 1993).

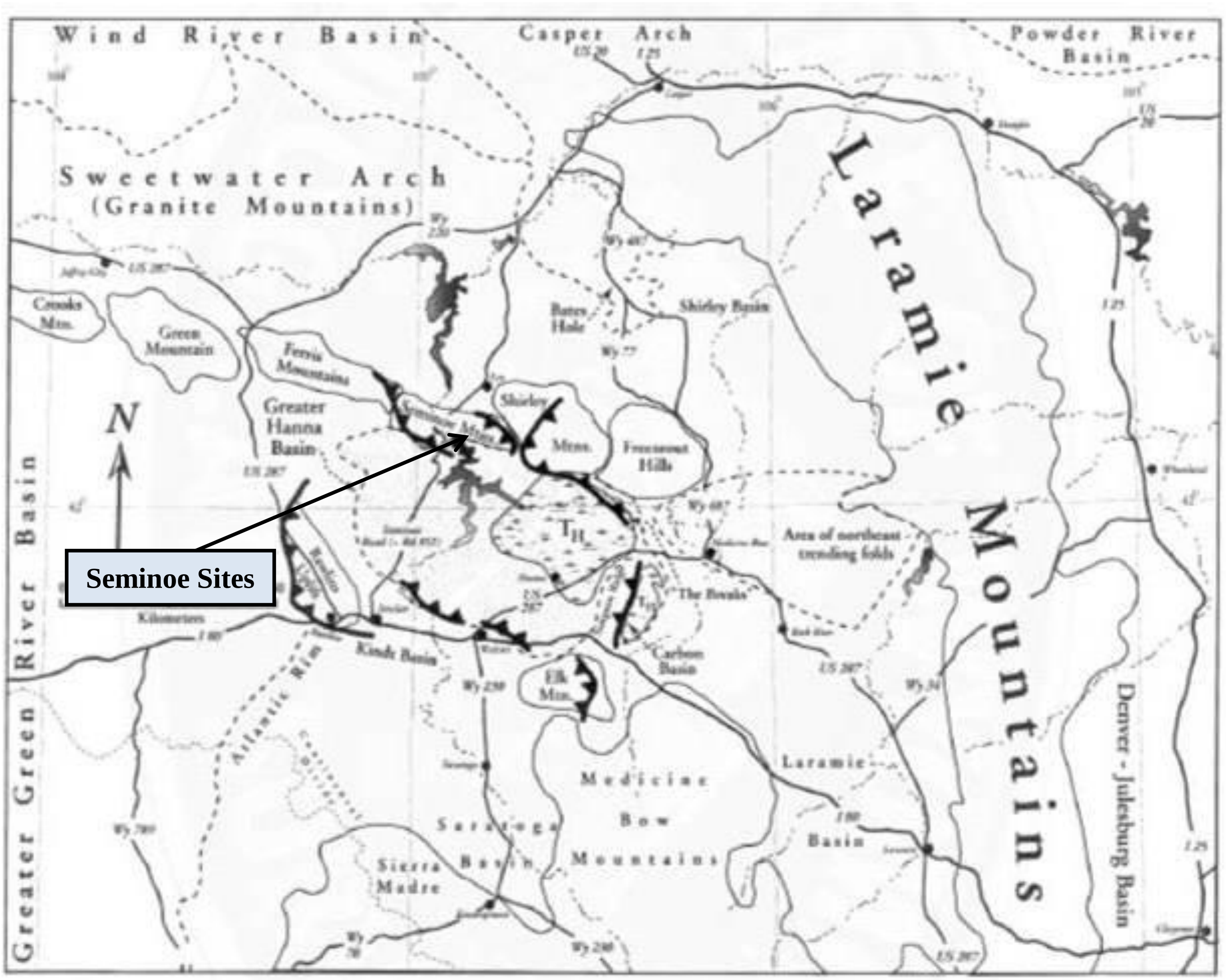
The major regional structure of the Wyoming Basin in the vicinity of the site is a broad northwest-trending uplift, the Sweetwater Arch that extends southeast from the vicinity of the southern Wind River Mountains to the Freezeout Hills (Figure 3-5; Blackstone 1965). Precambrian age crystalline rock outcrop in the central portion of the uplift and are surrounded by late Tertiary sediments with low dips. The granitic domes and knobs along the axis of the arch are known as the Granite Mountains. Crooks Mountain, Green Mountain, Ferris Mountains, Seminoe Mountains, Shirley Mountains, and Freezeout Hills are along the arch's southwest margin that is marked by folded and faulted sedimentary rocks (Paleozoic and younger; Blackstone 1965; Figures 3-5 and 3-6).

Figure 3-4. Physiographic Provinces Surrounding the Proposed Seminoe Sites



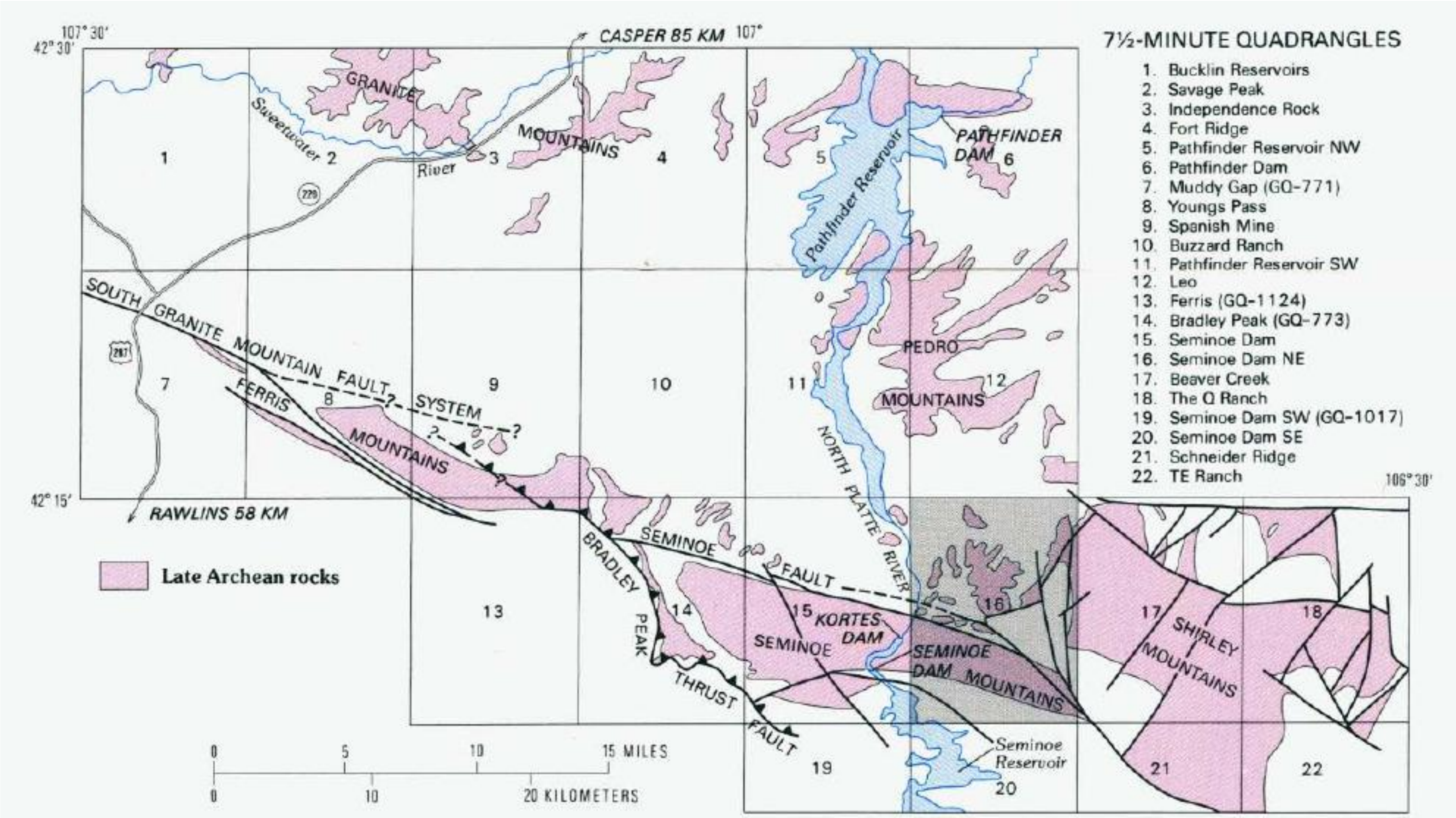
Source: Geomatrix 1988

Figure 3-5. General Tectonic Features Surrounding the Area of the Proposed Pumped Storage Sites



Source: Lillegraven and Snoke 1996

Figure 3-6. Map Showing the Location of Late Archean Rocks and Main Faults in the Southern Part of the Granite Mountains Area



Source: Dixon 1990

3.2.2 Site Geology

The sites are within the Seminoe Mountains along the southeastern margin of the Sweetwater Arch. The mountains are cored by Archean age (>2.7 Ga) metasedimentary and metavolcanic rocks of lower amphibolite metamorphic grade intruded and folded by slightly younger granitic and granodioritic rocks that were uplifted during the Laramide orogeny (80-35 Ma; Hausel 1982, 1994). The mountains are bounded on the southwest by a low-angle reverse fault (Figure 3-6; Bradley Peak thrust). This fault places the Archean age rocks on sedimentary rock of Paleozoic and younger age (<550 Ma; Hausel 1982, 1994). The north side of Seminoe Mountain is bounded by the Seminoe reverse fault, a Precambrian shear zone that was reactivated during the Laramide orogeny and late Cenozoic deformation (Hausel 1994). Along the north margin of the mountains is the Seminoe Mountains section of the South Granite Mountain fault system.

The geologic map of the site vicinity is shown in Figure 3-7. Geologic formations of significance to the potential sites (reservoirs and underground structures) are (map by Jones and Gregory 2011; descriptions from Dixon 1990):

QaC – (Quaternary). Alluvium, colluvium, terrace and pediment deposits.

Pge – Goose Egg Formation (Lower Triassic and Permian). Pale-red to reddish-brown siltstone containing thin layers of light-gray limestone and dolomite. 260 to 295 feet thick.

$t – Tensleep Sandstone (Middle Pennsylvania). Grayish-yellow, fine- to medium-grained, calcareous quartzite containing beds of light-gray dolomite near the base. About 740 feet thick.

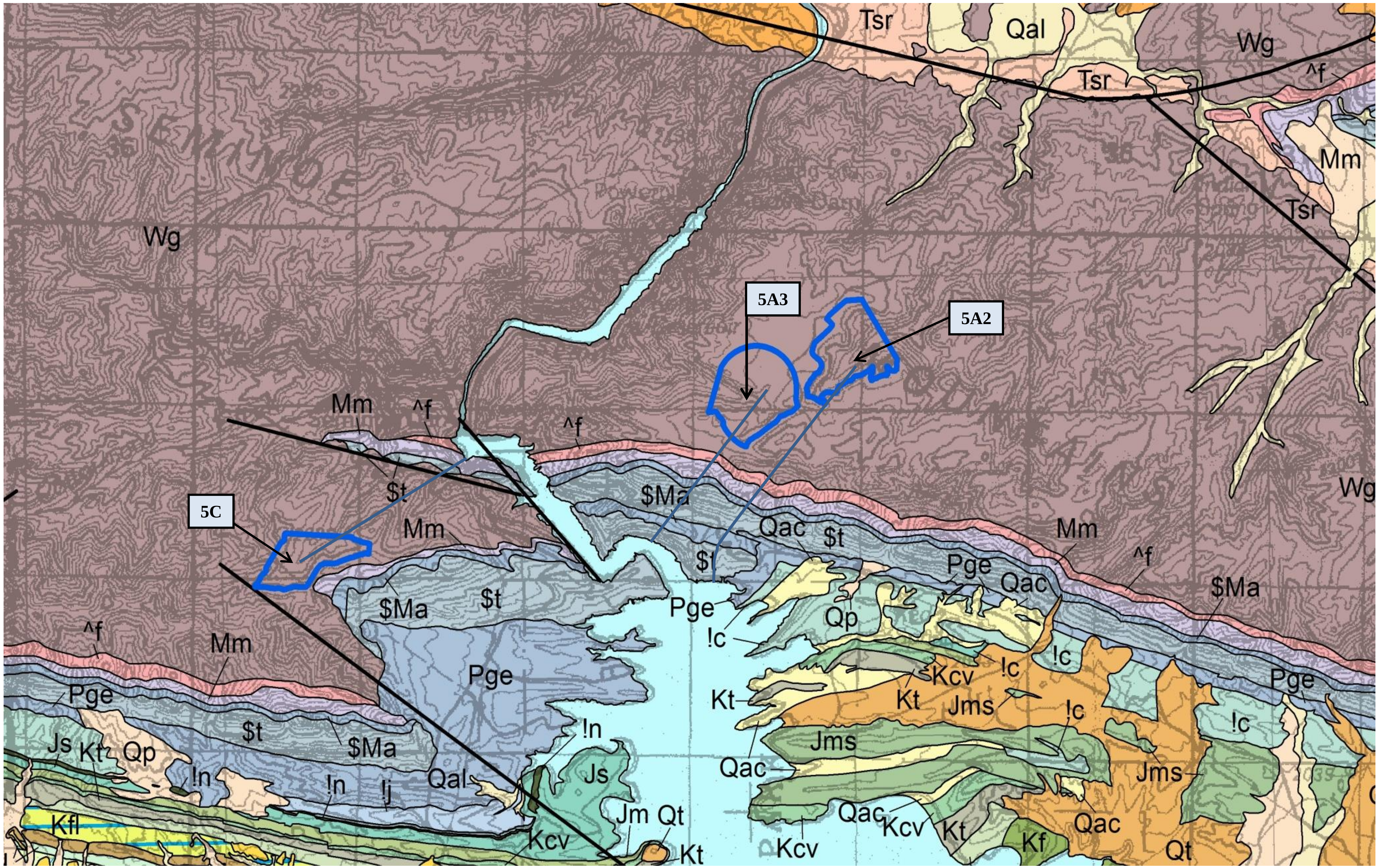
$Ma – Amsden Formation (Middle and Lower Pennsylvanian and Upper Mississippian). Pale-reddish brown to grayish-red siltstone and mudstone interlayered with thin, grayish-pink limestone beds. Poorly exposed but generally forms a topographic low between the more resistant Amsden Formation above and Madison Limestone below. About 100 feet thick.

Mn – Madison Limestone (Upper and Lower Mississippian). Light-fray, fine- to medium-grained limestone containing thin beds and nodules of medium-gray chert. About 360 feet thick.

^f – Fremont Canyon Quartzite (Upper Devonian) and **Flathead Quartzite** (Middle Cambrian) - Undivided. Pale-red, grayish-red, and grayish-orange pink, medium- to coarse-grained quartzite. The basal part is commonly cross-bedded conglomerate containing clasts up to 1 inch long of quartz, quartzite, and dark-gray phyllite. About 85 feet thick.

Wg – Granite and Gneiss, undivided (Precambrian - Archean). Rock types include dark gray, fine- to medium-grained amphibolite, medium dark-gray, fine-grained, biotite-quartz-andesine schist, and very light gray to medium gray, fine- to medium-grained, well-foliated granitic gneiss (located along the northern boundary of Seminoe Mountains in the vicinity of the sites) intruded by grayish-orange-pink, medium-grained, massive granite (Granite of Seminoe Dam) and light gray, medium-grained granite (Granite of Kortes Dam), white granite occurs in dikes and sills in the above rocks and texturally varies from aplitic to pegmatitic, and dark gray to dark-greenish-gray, fine-grained diabase occurring as dikes in the above rocks.

Figure 3-7. Geologic Map of the Seminoe Site Vicinity



Source: Jones and Gregory 2011. See text for rock unit descriptions.

The Archean rocks (Wg) underlie most of the Seminoe Mountains (Figure 3-7). These rocks have been affected by Precambrian faulting (in particular the Seminoe Fault along the northern flank of the mountains) and folding as well as by the later Laramide uplift and faulting (Dixon 1990). Steeply-dipping Paleozoic and Mesozoic rocks overlie the Archean rocks south of Seminoe Mountains (Figure 3-7).

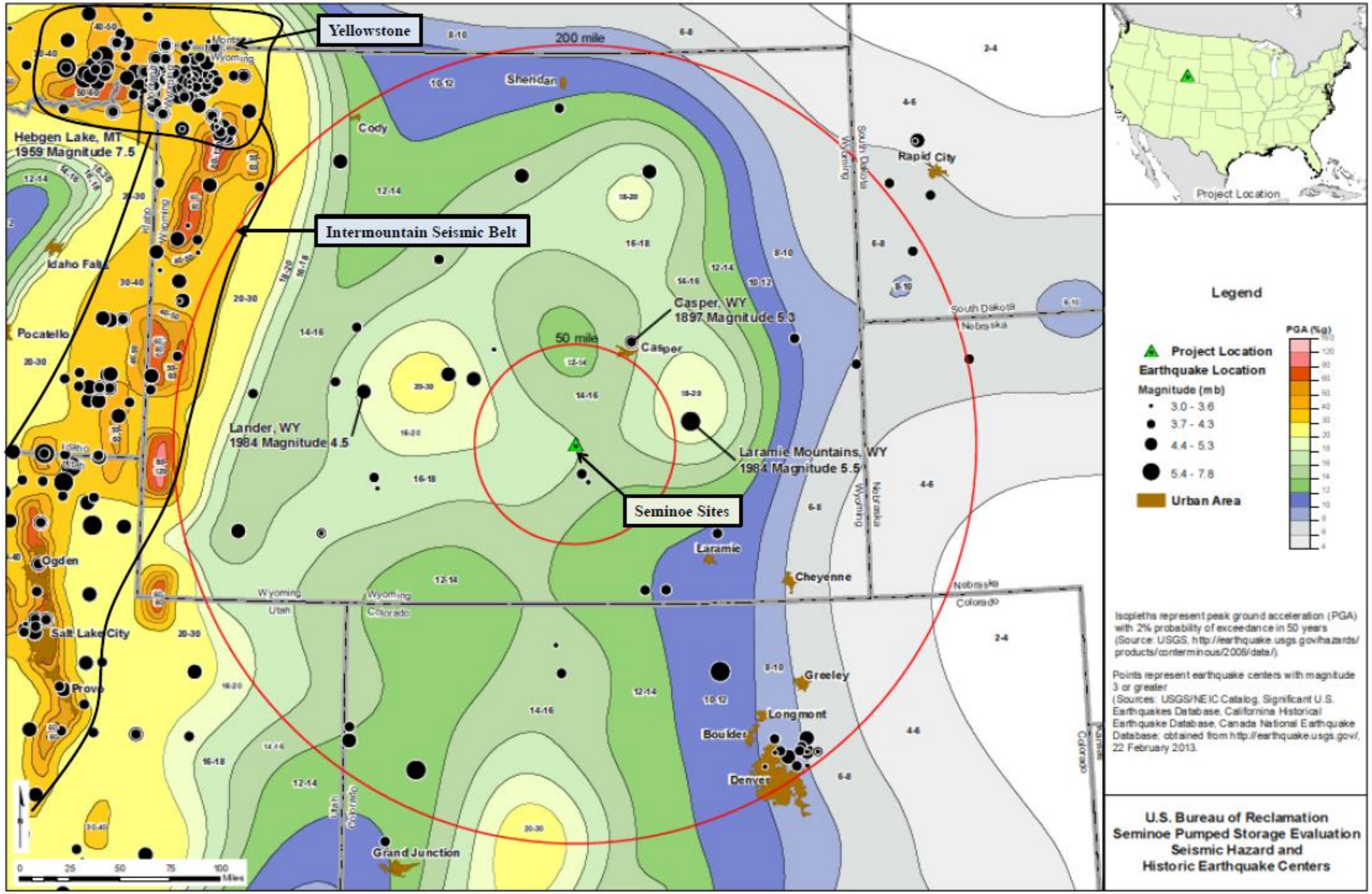
The proposed dams and reservoirs will be underlain by the Archean granitic rocks and the underground structures would be constructed in both these rocks and the overlying Paleozoic rocks along the south side of the Seminoe Mountains.

3.2.3 Regional and Local Seismicity

A low level of historical seismicity characterizes the Wyoming Basin (Figure 3-8) with no apparent correlation of historical epicenters to tectonic structures including the Cenozoic faults (including the South Granite Mountain fault near the proposed site). Western Wyoming is relatively active and the seismicity is occurs in the Intermountain Seismic Belt and the seismically and volcanically active Yellowstone region (Figure 3-8).

Within 50 miles of the site, two earthquakes have been recorded with a magnitude greater than 3.0 (Figure 3-8). The largest earthquakes within 100 miles of the site are the Laramie Mountain EQ (M5.5) on October 18, 1984, the Casper EQ (M5.3; estimated) on November 14, 1987, and the Lander EQ (M4.5) on November 30, 1984 (Figure 3-8). The closest event to the site with >M3 occurred on August 3, 1973 about 15 miles from the site with a M4.1. The U.S. Geological Survey (USGS 2008) Seismic Hazard Maps indicates a peak ground acceleration (PGA) in the project area of 0.16 g with a recurrence interval of 2,475 years (2 percent probability of exceedance in 50 years; Figure 3-8; USGS 2008).

Figure 3-8. Historic Earthquake Epicenters and Seismic Hazard for the Seminoe Sites



Late Quaternary faulting that could generate strong ground shaking at the proposed sites has been identified along two segments of the South Granite Mountain Fault (Geomatrix 1988). Geomatrix (1988) divided the fault into five segments; from west to east these are the Crooks Mountain, Green Mountain, Muddy Gap, Ferris Mountain, and Seminoe Mountains segments. The Ferris Mountain and Green Mountain segments exhibit late Quaternary movement (Geomatrix 1988). Displacement on the fault segments is high angle dip-slip with the north side down. Geomatrix (1988) developed Maximum Credible Earthquakes (MCE) for use in evaluating five Bureau of Reclamation dams in the Wyoming Basin. The MCE and random earthquake developed for Seminoe dam are presented in Table 3-2. These estimates will need to be re-evaluated during the next phase of study. The sites are in an area of low to moderate risk.

Table 3-2. Maximum Credible Earthquakes for Seminoe Dam

Source	MCE	Focal Depth (km)	Distance (km)	Estimated Recurrence (years)
Ferris Mountain Segment	M_S 6.5 – 6.75	10 - 20	29	5000 –to13,000
Green Mountain Segment	M_S 6.75	10 - 20	60	2000 to 6000
Random Earthquake	M_L 6.5	10 - 15	34	50,000

3.2.4 Evaluation of Geological Characteristics

This evaluation was based on a review of published maps and papers and relates this information, when possible, to the likely geological characteristics of the materials and bedrock underlying the three sites. The preliminary findings are summarized in Table 3-3. A detailed literature search and a geologic field reconnaissance was not part of this study phase.

Table 3-3. Summary of Geologic Characteristics

Geological Characteristic	Relation to Project Areas
High seismic risk/active faulting within the Project area	The Project area is considered to have low to moderate seismic risk. Active faults (Holocene movement) not present in the immediate vicinity, but early Quaternary movement has occurred along the Seminoe Mountains section of the South Granite Mountain fault system located just north of the sites. Late Quaternary movement has occurred on two sections of the South Granite Mountain fault system to the northwest indicating a potential for strong ground shaking at the sites.
Active volcanism	None in immediate vicinity. Nearest volcanic center is to the northwest at Yellowstone.
Active landslides in Project area	Current landslide activity is not known at this stage of the study for the Project sites.
Karst topography in reservoir area	Not present in the reservoir area. Not known if karstic conditions are present in the Madison Limestone. No reference to this during initial literature review.

Table 3-3. Summary of Geologic Characteristics

Geological Characteristic	Relation to Project Areas
Groundwater conditions in reservoir areas presenting controllable/uncontrollable leaking potential	Not known at this stage of the study for the Project area, but likely not an issue for leakage potential.
Deep chemical weathering profile	Total soil thicknesses along the reservoir rim are not known but are thought to be shallow based on the literature review.
Highly permeable rock	Not known at this stage of the study for the Project areas. Granites are likely low permeability. Limestone that will be encountered in the tunnels could be permeable (open, solutioned fractures).
Soluble rock material	Will be present in the water conveyance tunnels for all three sites. Present condition of limestones in the Paleozoic section are not known. In other areas, the Madison Limestone has caves, caverns, and solutioned, open fractures. Limestone also present as interlayers in the Goose Egg and Amsden Formations.
Low strength, vibration-sensitive, friable, highly abrasive, slaking, or unlithified rock material	Not present at the reservoir sites. Possibly present in the tunnel alignments within the Paleozoic rocks.
Highly faulted, folded, or fractured rock material	Archean rocks in places highly faulted/sheared, but generally recrystallized/healed. Fracture nature of the sedimentary rocks south of Seminoe Mountains not known at this stage of the study.
Thinly laminated, structurally deformed, fine-grained rock masses	Rocks of the Goose Egg Formation (siltstone with thin limestone interlayers), Tensleep Sandstone (fine-grained rocks), and Amsden Formation (siltstone and mudstone with thin interlayered limestones) will be present in the tunnels.
Stress-relieved reservoir rims	Not known at this stage of the study for the Project sites, but stress-relief during uplift and erosion of the Archean granitic rocks is possible.
Soils conducive to liquefaction	Soil deposits (Quaternary alluvium) in the Project site are subject to liquefaction.

3.2.5 Constructability

The proposed dams would be built on granite. The water conveyance tunnels, access tunnels would be built in both the granite and in quartzite, sandstone, siltstone, mudstone, and limestone of the Paleozoic sequence. The proposed powerhouse location for Site 5C would be in the granite. The proposed powerhouse locations for Sites 5A2 and 5A3 would likely be in the granite, but they would be close to the steeply-dipping to the south sedimentary rocks. Preliminary projection of the granite-sedimentary rock sequence contact suggests the powerhouses would be in the granite and would require verification during the next phase of study.

A potential dam foundation issue is leakage through high-angle fractures and low-angle stress relief (sheeting) fractures that develop in some granitic bodies at the ground surface. In general, hard, massive granitic rocks should provide an adequate foundation for all types of dams including concrete-faced rock-fill dams that are proposed for the three sites.

In general granitic rocks can be almost ideal for underground construction. Potential issues related to the construction of the water vertical shaft, water tunnels, access tunnels, and powerhouses are: 1) in granites where jointing is close or where faults or hydrothermally altered zones are encountered, supports may be required; 2) high stresses could be encountered which could result in cracking and forming slabs and in cases could lead to rock bursts (extra rock bolting would be required under the first condition; rock bursts can stop progress until the possibility of explosive detachment of rock is eliminated by time or application of reinforced shotcrete, wire mesh, and rock bolts); 3) the steeply-dipping sedimentary rocks can present stability problems in the tunnel and powerhouse crowns (and in the excavation slopes for the discharge/intake structure on the lower reservoir); 4) potential strength and stability issues related to thinly interbedded mudstone, siltstone , fine-grained sandstone, and limestone that will be encountered in portions of the underground structures; and 5) underground construction in limestones can lead to sudden inflows of water, unstable tunnel faces and roof/crown conditions due to clay and weathered rock, and block slides along bedding planes with mud/clay seams (Goodman 1993).

The hard massive granitic rock should be suitable for both rock fill for dam construction and as concrete aggregate. This should be verified during the next phase of study.

3.2.6 Conclusions

No fatal flaws related to geology and seismology were identified during this preliminary desktop study.

3.3 Trinity 5G2A

3.3.1 Regional Geology

The Trinity site is located in the Klamath Mountains of northern California. The Klamath Mountains consists of an imbricate stack of terranes bounded by east-dipping thrust faults of Mesozoic age (Harden 2004). Paleozoic rocks occur in three broadly defined structural belts, eastern, central, and western. The site is within the eastern belt which is subdivided into three parts. The structurally lowest is the Trinity Ultramafic Complex. It is overlain to the north by lower Paleozoic sedimentary and metasedimentary rock of the Yreka-Callahan area. To the southeast, the Trinity Complex is structurally overlain by a Devonian through Jurassic island arc-sequence, the Redding section that includes metasedimentary strata and intercalated metavolcanic units (Miller et al. 1992). The section’s contact with the Trinity complex is of uncertain nature, but is thought to be a thrust fault (Burchfield et al. 1992; Jennings et al. 2010).

3.3.2 Site Geology

A site reconnaissance was performed on April 1 and 2, 2013. Part of the following site geology description is based on the site reconnaissance and on the available geologic mapping and technical literature. A geologic map of the site is shown on Figure 3-9. Rock forms in the vicinity of the site, from the youngest to oldest, are listed as follows (bold initials refer to map designations on Figure 3-9; descriptions from Miller et al. 1992; Wagner and Saucedo 1987):

Qal – ALLUVIUM (Quaternary). Recent alluvium, old alluvium, and young stream terrace deposits, poorly sorted stream and basin deposits, clay to boulder size.

Qag – GLACIAL DEPOSITS (Quaternary - Pleistocene). Rock glaciers, morainal deposits, and outwash.

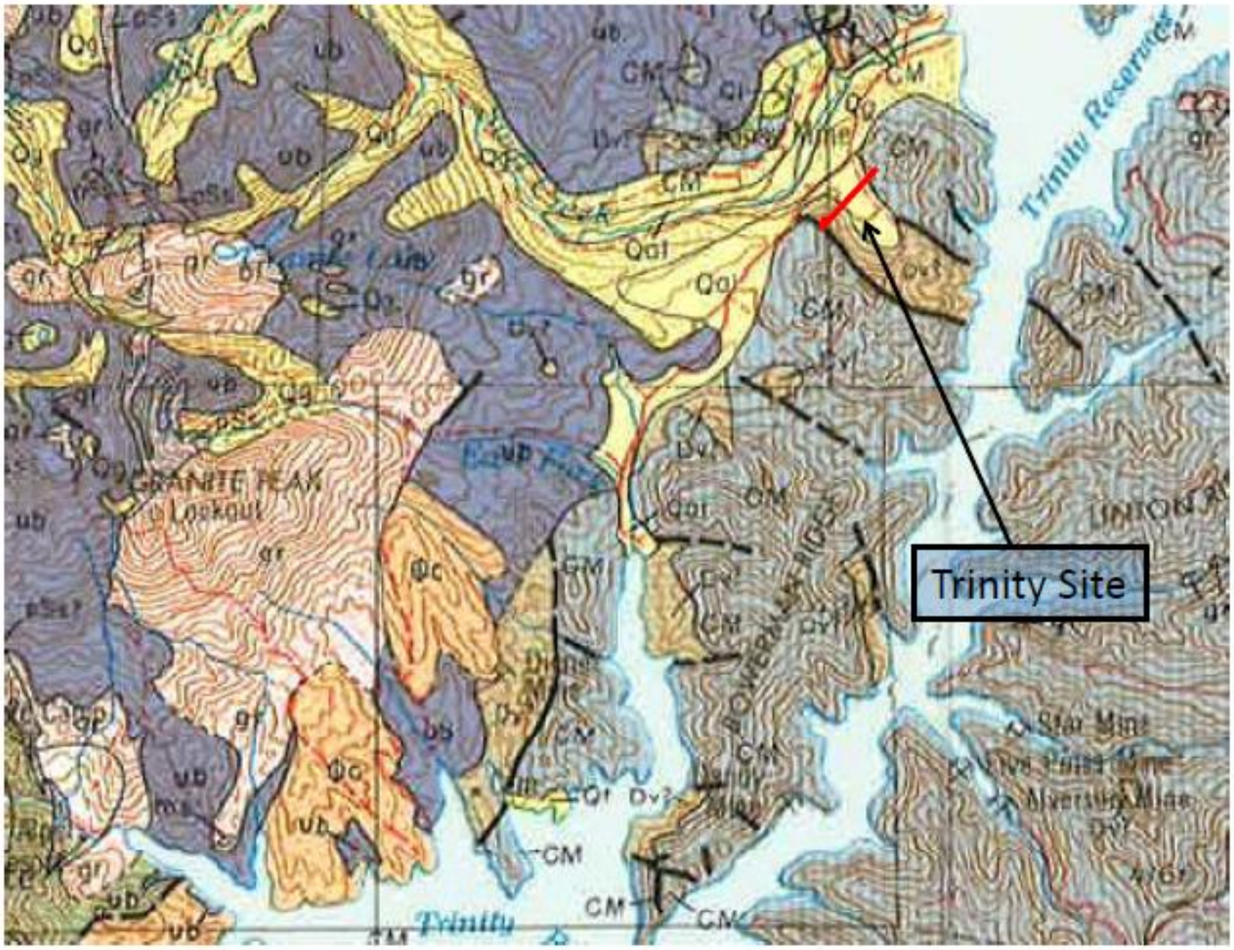
gr – GRANITIC ROCKS (Mesozoic). Granitic and dioritic batholiths.

CM – BRAGDON FORMATION (Mississippian). Marine sedimentary and metasedimentary rocks, dark greenish gray to black thinly-bedded meta-shale, interstratified metamorphosed siltstone, sandstone, and conglomerate in the upper part and metamorphosed local thin-bedded chert, rhyolitic tuff, and mafic volcanic rocks in the lower part. The Bragdon Formation is a turbidite sequence with sedimentary clasts including chert, argillite, and quartzose to feldspathick sandstone and metasedimentary clasts include greenschist-grade equivalents of the sedimentary lithologies. Volcanic debris is characterized by volcanic quartz, plagioclase, and rare lithic fragments. In place, in fault contact with the underlying rock units.

Dv? – COPLEY GREENSTONE (Devonian). Fine-grained massive flows and pyroclastic debris (tuffs) in the lower part of the unit and amygdaloidal pillow lava and fine- to coarse- pyroclastic material (tuffs) in the upper part of the unit. Sandstone containing granular debris and shaley tuffs is locally interbedded with the pillow lavas.

ub – TRINITY ULTRAMAFIC COMPLEX (Ordovician). Ultramafic rocks including harzburgite, dunite, peridotite, and serpentinized equivalents cut by gabbros, norites, and diorites.

Figure 3-9. Geologic Map of the Trinity Site Vicinity



Source: Strand 1962. See text for rock unit descriptions.

A large portion of the proposed dam and reservoir site is underlain by Quaternary alluvium (Qal) and/or lake deposits of unknown thickness. Downstream of the dam centerline are glacial deposits consisting of morainal deposits (Qag) that include large boulders. The left abutment is underlain by rocks of the Copley Greenstone. Rock types include fine-grained andesitic flows and tuffs that are generally highly fractured. The right abutment is underlain by rocks of the Bragdon Formation including meta-shale and siltstone with interlayered sandstone and conglomerate with chert layers and is highly fractured. The Intake Structure, water conveyance tunnels, the powerhouse and access tunnels will likely be in the Copley Greenstone unit, although portions of the main access tunnel may be in the Bragdon Formation. The highly fractured nature of the two rock units was noted during the construction of the Trinity River Project (Bureau of Reclamation 1965).

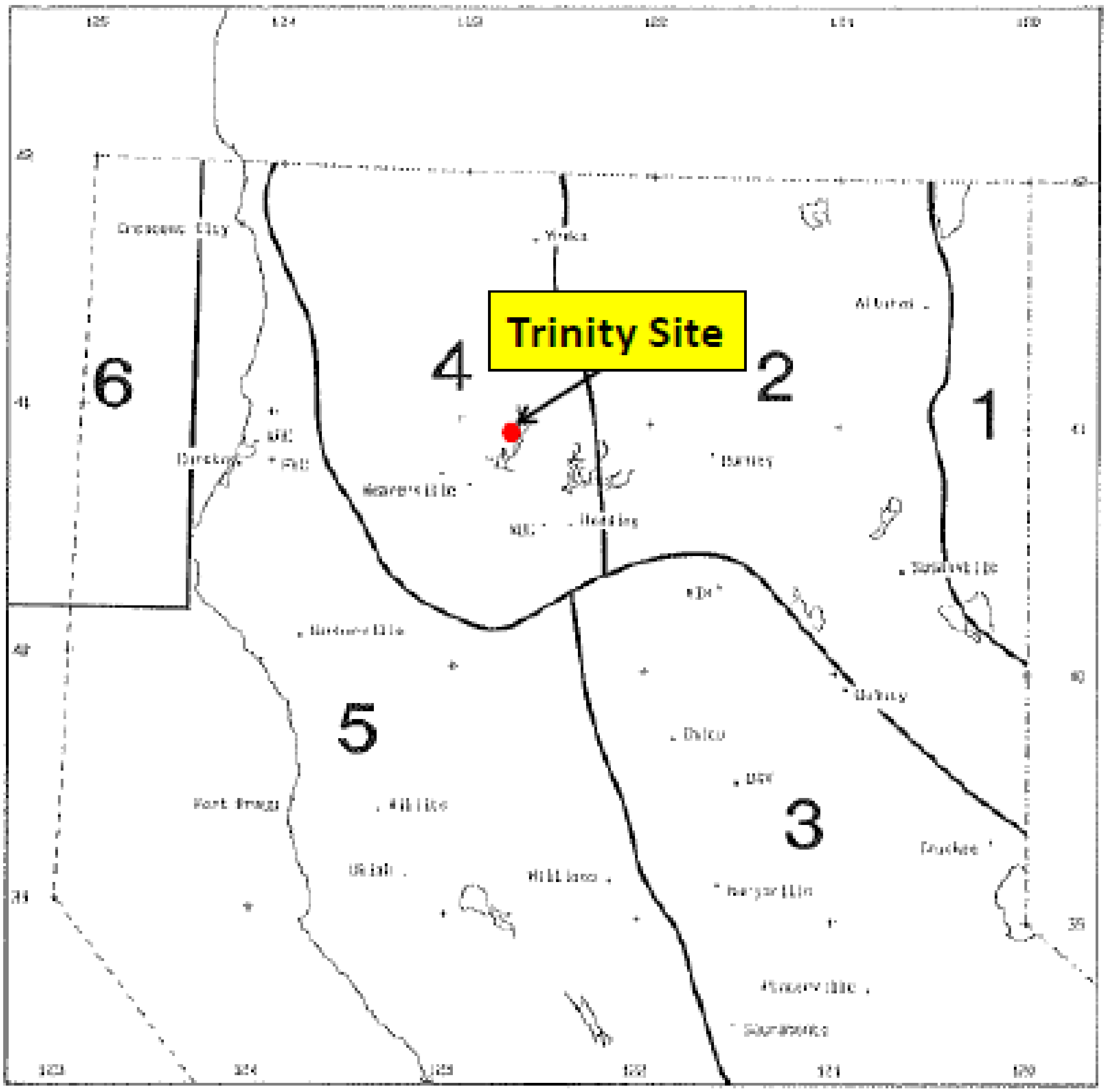
The geologic map of the area (Strand 1962) shows the Copley Greenstone in fault contact (NW-striking faults) with the Bragdon Formation. A similar relationship, Bragdon Formation downfaulted into the Copley Greenstone, was noted along the Trinity River during the construction of the Trinity River Project. (Bureau of Reclamation 1965). The site reconnaissance along the left reservoir rim found some evidence for the existence of the southwestern most fault, which is just outside of the reservoir area. Several faults were noted along Trinity Reservoir in the vicinity of the northeastern fault. The faults are not active as defined by the California Department of Dam Safety (Jennings and Bryant 2010).

3.3.3 Regional and Local Seismicity

Northern California is a geologically complex region that exhibits a wide variation in its characteristic seismicity (Uhrhammer 1991). Uhrhammer (1991) defined six structural provinces in the region as shown in Figure 3-10. The Gorda Basin (6) is the most active and is related to the Mendocino Fracture Zone, Gorda Ridge, and Blanco Fracture Zone, and the subduction of the Gorda Plate and Juan de Fuca Plate along an eastward-dipping Benioff zone. Moderate seismicity occurs in the Northern Coast Ranges (5), primarily along the South Fork Mountain fault zone (boundary with the Klamath Mountains) and the Maacoma Fault zone. A concentration of seismicity is associated with Lassen Peak in the Modoc Plateau province (2), but has a general trend of scattered earthquakes of northwestward to north from the eastern flank of the Sierra Nevada province (3). The eastern flank of the Sierra Nevada province has produced several large magnitude earthquakes and the Foothills fault system along the western side has moderate seismicity associated with it. The Warner province (1) exhibits a very low level of seismicity. The Klamath Mountains province (4), in which the Trinity site is located, exhibits a low level of seismicity compared to the surrounding provinces. Most of the events occur along the western side in the vicinity of the South Fork Mountain fault. A few events have occurred in the eastern half of the province between Redding, Yreka, and Weaverville. Quaternary faulting has not been recognized in the vicinity of the site (Jennings and Bryant 2010).

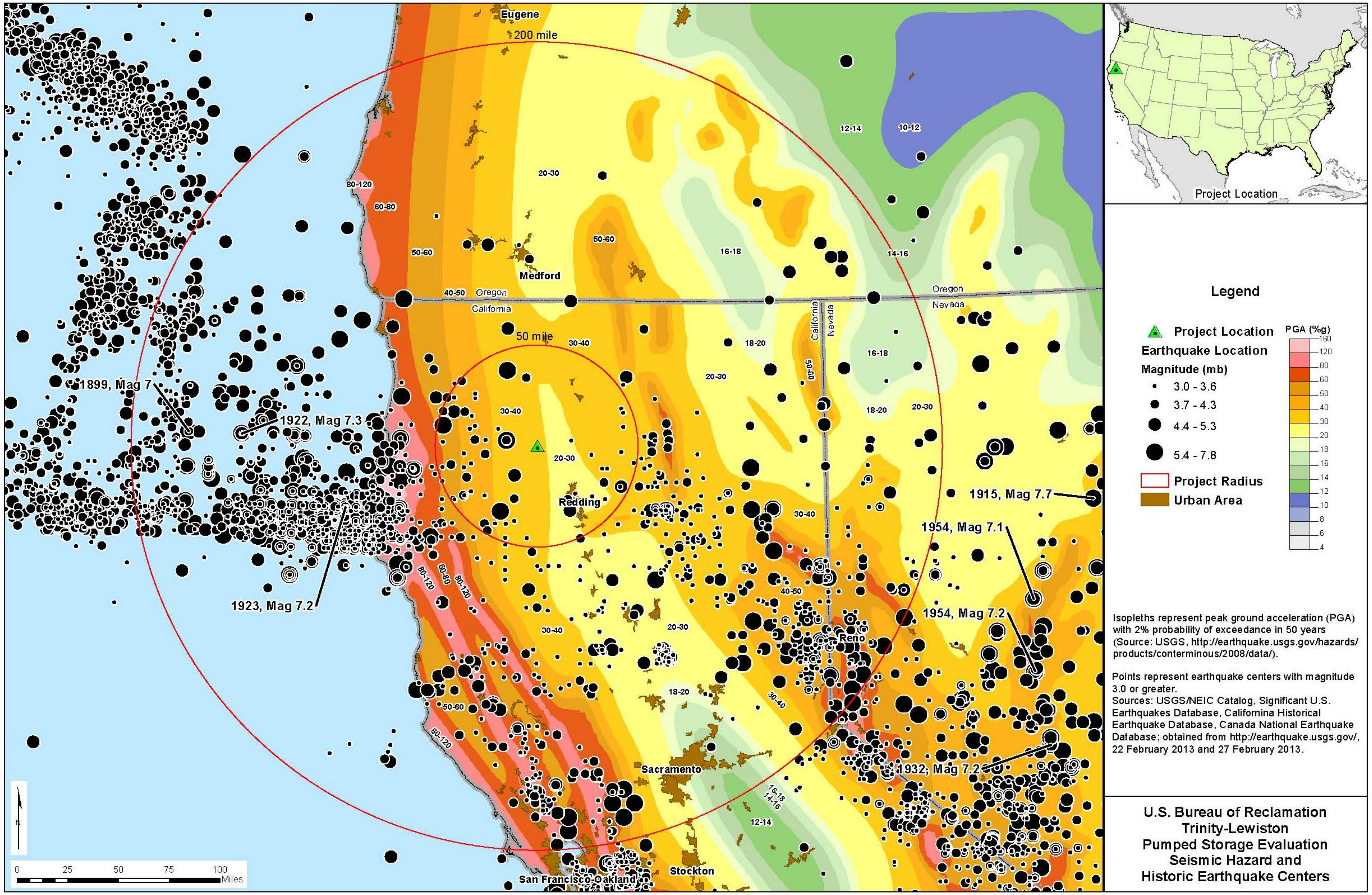
Within 50 miles of the site, 62 earthquakes have been recorded with a magnitude greater than 3.0 (Figure 3-11). The largest of M 6.6 occurred about 37 miles from the site on December 21, 1954. The closest event to the site occurred on June 3, 1925 about 15 miles from the site with an estimated M 5.6. The U.S. Geological Survey (USGS 2008) Seismic Hazard Maps indicates a PGA in the project area of 0.30g to 0.40g with a recurrence interval of 2,475 years (2 percent probability of exceedance in 50 years; Figure 3-11; USGS 2008).

Figure 3-10. Structural Provinces in Northern California



(1) Warner,; (2) Modoc Plateau; (3) Sierra Nevada; (4) Klamath Mountains; (5) Northern Coast Ranges; and (6) Gorda Basin. After Uhrhammer (1991).

Figure 3-11. Trinity Pumped Storage Project Seismic Hazard and Historic Earthquake Centers



3.3.4 Evaluation of Geological Characteristics

This evaluation was based on a review of published maps and papers and a site reconnaissance visit and relates this information, where possible, to the likely geological characteristics of the materials and bedrock underlying the two sites. The preliminary findings are summarized in Table 3-4. A detailed literature search and detailed geologic field reconnaissance was not part of this study phase.

Table 3-4. Summary of Geologic Characteristics

Geological Characteristic	Relation to Project Areas
High seismic risk/active faulting within the Project area	The Project area is considered to have moderate to high seismic risk. No Quaternary/active faults in the site vicinity.
Active volcanism	Mount Shasta and Lassen Peak are located northeast and southeast of the site. Lassen erupted from 1914 to 1922. Last eruption at Mount Shasta about 225 years ago (1786).
Active landslides in Project area	Current landslide activity is not known at this stage of the study for the Project sites. The deep weathering profile along the reservoir rim suggests a potential for landslides, but none were noted during the field reconnaissance.
Karst topography in reservoir area	None.
Groundwater conditions in reservoir areas presenting controllable/uncontrollable leaking potential	Not known at this stage of the study for the Project area. Quaternary alluvial (fluvial?) materials underlying a large portion of the reservoir site may provide potential leakage paths under the dam unless the materials are removed from under the dam or a positive cutoff installed. Highly fractured bedrock in the reservoir rims and underlying the reservoir may have leakage potential.
Deep chemical weathering profile	Total soil thicknesses along the reservoir rim are not known, but a deep weathering profile was noted in places along the reservoir rim and along the shoreline of Trinity Reservoir during the field reconnaissance.
Highly permeable rock	Not known at this stage of the study for the Project area. Large in-flows of water may occur in the underground works due to the intense fracturing of the rocks included within the Copley Greenstone and Bragdon Formation.
Soluble rock material	Not present.
Low strength, vibration-sensitive, friable, highly abrasive, slaking, or unlithified rock material	Meta-shales and siltstones of the Bragdon Formation are relatively low strength. Due to intense fracturing rock mass strengths are likely on the low side.
Highly faulted, folded, or fractured rock material	Rocks of both the Copley Greenstone and Bragdon Formation are highly fractured and in places highly faulted (Bureau of Reclamation 1965).
Thinly laminated, structurally deformed, fine-grained rock masses	The meta-shales and siltstones of the Bragdon Formation, are fine-grained and thinly laminated. The lava flows and tuffs of the Copley Greenstone are fine-grained and in places thinly laminated.
Stress-relieved reservoir rims	Not known at this stage of the study for the Project sites.
Soils conducive to liquefaction	Soil deposits (Quaternary alluvium) in the Project site are subject to liquefaction.

3.3.5 Constructability

The dam would be founded on rocks of the Copley Greenstone and Bragdon Formation (after removal of the overlying alluvial deposits). The water conveyance systems, access tunnels, and powerhouse, would be constructed primarily in rocks of the Copley Greenstone.

Potential dam foundation issues are:

- A large area under the footprint of the proposed dam is underlain by alluvial materials. It would require removal before construction of any type of dam due to foundation strength, liquefaction potential, and seepage under the dam.
- Mixed bedrock types in the foundation of the dam could result in differential settlement.
- Weak seams may be present in the foundation.
- Highly fractured bedrock could lead to seepage under the dam requiring substantial curtain grouting.

The potential reservoir issue is excessive leakage through areas with deep weathering profiles and highly fractured rock.

Potential issues related to the construction of the water conveyance tunnels (including vertical shaft), access tunnels, and underground powerhouse are: 1) potential stability problems in the vertical shaft, tunnels, and powerhouse due to the fine-grained, thinly laminated, and highly fractured rock that could result in additional support requirements and could limit the open span of an underground excavation; 2) potential water inflow during construction; and 3) suitable rock for concrete aggregate and construction of a concrete-faced rock fill dam is not present in the reservoir or immediate vicinity.

A soil dam may be possible if enough alluvium is located under the proposed dam, reservoir site, and nearby if the material is processed into appropriate gradations for use in zoned construction. A Mesozoic granitic pluton is located southwest of the site and would likely provide suitable rock for concrete aggregate and construction of a concrete-faced rock-fill dam or rip-rap for a soil dam.

3.3.6 Conclusions

There are some significant construction challenges, but no fatal flaws related to geology and seismology were identified during this preliminary study.

Chapter 4 Pumped Storage Evaluation – Single-Speed versus Variable-Speed Technology

4.1 Summary

A typical pumped storage plant uses electricity to pump water to the upper reservoir during periods of low-cost, off-peak power and generates electricity during periods of high-cost, on-peak power. This is typically referred to as an operating for energy arbitrage. A pumped storage project can also be operated to provide ancillary services. Pump-turbine technology is an important factor in the ability to provide ancillary services, mainly regulation. This chapter discusses the advantages and disadvantages of single-speed versus variable-speed pump-turbine technology as it applies to the pumped storage projects evaluated in this study.

In the case of conventional synchronous (single, constant speed) pump-turbine units, during generating mode, the individual units are operated to support grid requirements including load following; however, during pumping, the units are operated at best pumping gate (most efficient operation) with no capability for load following or regulation. During pumping mode, the wicket gate positions may need to be decreased as the reservoir water elevation increases in order to keep the units on the best pumping gate curve and to prevent cavitation and vibration (net head control). Deviation from this best pumping gate operation results in low efficiency and rough operation, with minimal change in power input requirements.

In the case of variable-speed (asynchronous) pump-turbine units, load following is possible during both the generating and pumping modes, and hence the primary difference between the two technologies. Variable-speed operation in this context normally means that the rotating speed of a unit does not vary by more than +/-10% of its synchronous speed. The varying output frequency of the generator is converted to the grid frequency through a special frequency conversion system. Other advantages of variable-speed units are higher and flatter generator efficiency curves, wider generating and pumping operating ranges, and easier start-up process. The main disadvantage of this technology is the higher capital costs, which are on average about 30% greater than conventional single-speed units.

4.2 Mechanical Components: Pump-Turbine Technology

There is no fundamental difference between a pump-turbine designed for single-speed operation and a pump-turbine designed for variable-speed operation. In the case of the Goldistahl pumped storage plant in Germany, which has both variable and single-speed units, the pump-turbines themselves are identical. The plant was placed in service in 2003 and has a total capacity of 1,060 MW. The plant has four units; two of them are single-speed and the other two are variable-speed units. Originally, the designer of the variable-speed pump-turbines (Voith Hydro) attempted to design optimized runner profiles within an identical runner band and crown for both the variable-speed and constant synchronous-speed machines. The development process finally provided a solution for both types of machines with the same identical runner. This also allowed for a single spare runner at the facility.

It is possible that the pump-turbine rating or size could change slightly for a greenfield plant due to the fact that variable-speed may allow for use of more reservoir volume because of the wider operating head range.

The control system for a variable-speed pump-turbine must provide a two-dimensional cam for pumping operations. Although the pump still operates at “best gate” at all times, best gate operation is a function of speed as well as head.

Higher efficiency levels in the generating mode are achieved by reducing pump-turbine speed as much as possible over the majority of the operating range. Only at high power requirements is the speed increased beyond the minimum. Since a pump-turbine hydraulic design is generated primarily as a pump with generating capability, the peak of the Hill Chart is always at a higher operating net head than the normal operating range. Thus, the lower speed “shifts” the operating range closer to the peak efficiency as shown in Figure 4-1.

This increase in generating efficiency may be offset by higher excitation losses. Thus, combined turbine/generator/excitation efficiencies should be used as a comparison when evaluating alternatives. Operation of the units at lower power outputs while generating is directly attributable to the higher efficiency levels at part load when operating at lower speeds. As seen from the above Hill Chart, efficiency will remain higher for a given power output, indicating that a variable-speed unit will have greater turndown capability and a wider regulating range. This will depend on unit-specific speed, but an increase in regulating range of 10% to 20% is a reasonable expectation.

Pump regulating capability is normally limited by generator-motor capability at low operating heads and by pump instability at high operating heads. Alstom provides a simplified chart of this restriction as shown in Figure 4-2.

Figure 4-1. Effect of Lower Speed in the Turbine Cycle

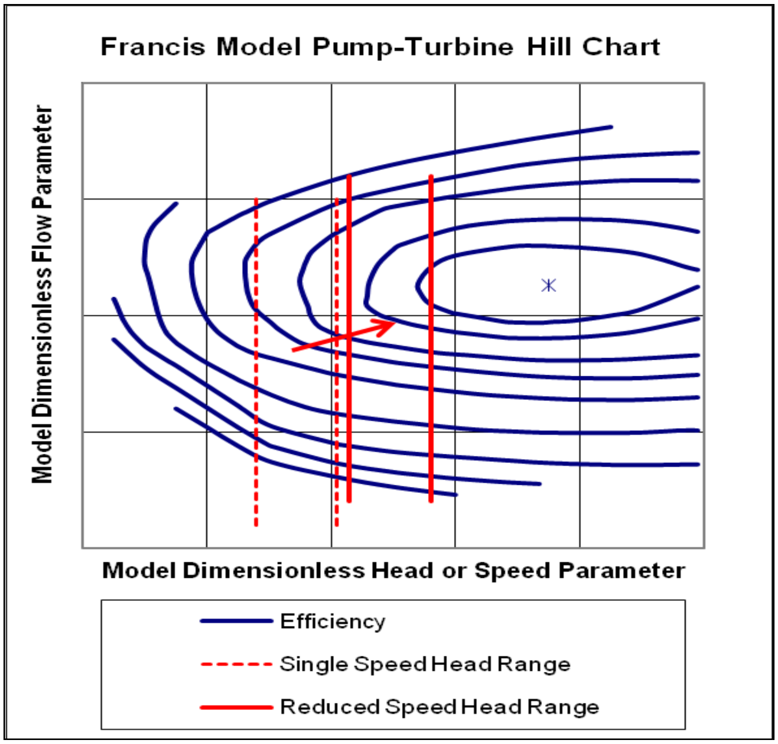
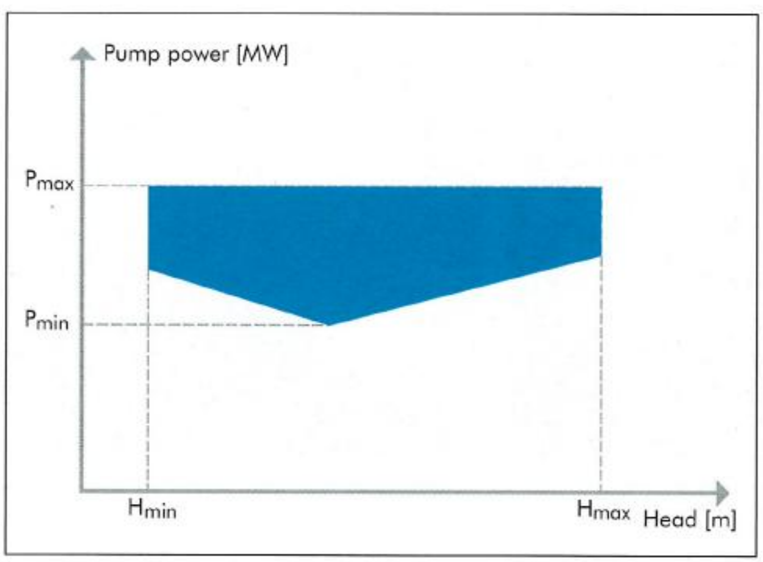
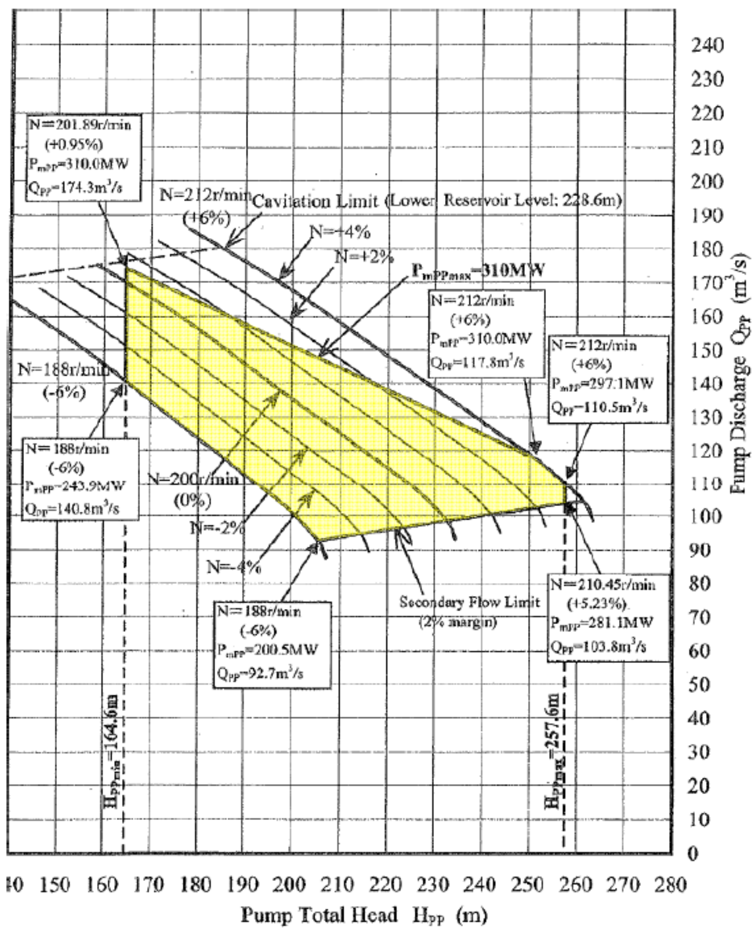


Figure 4-2. Pump-Turbine Typical Regulating Range



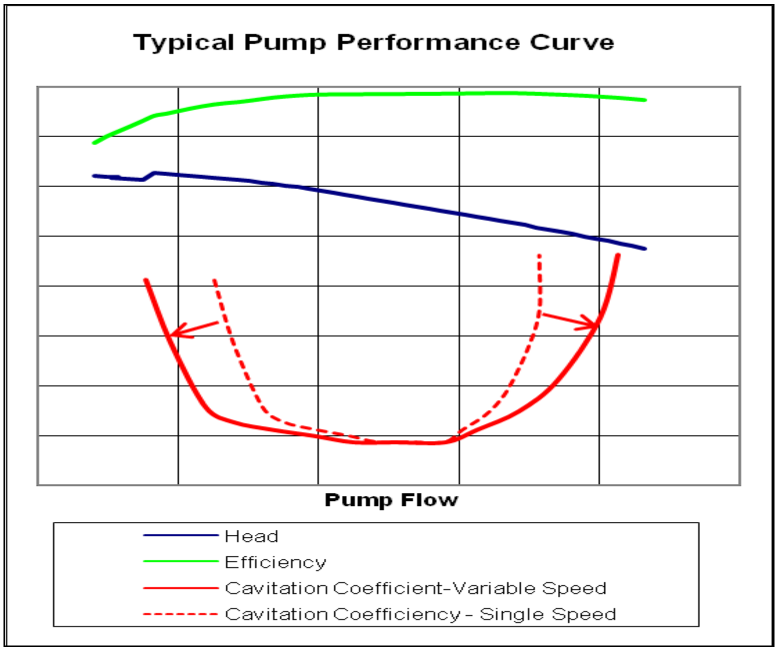
In practice, this working regulating range may shrink beyond original expectations if the operating head range is wide. Figure 4-3 displays the working regulating range for a representative project (highlighted in yellow). This effect will be minimal at projects where the head range is narrow, but it must also be considered when analyzing the project benefits.

Figure 4-3. Example Of Regulating Range Limitations



One additional possible advantage of variable-speed for a new plant is an increase in unit setting (i.e., higher elevation of the runner relative to tailwater level). The setting of a pump-turbine is dependent upon pump cycle cavitation performance. A pump normally has a cavitation "bucket" (the operating range to avoid cavitation) and variable-speed widens this bucket as depicted in Figure 4-4. For plants with narrow operating ranges, there is no setting advantage.

Figure 4-4. Improved Pumping Cavitation Performance With Variable-Speed



4.3 Electrical Components: Generator-Motor/Excitation Technology

For installations with a power output lower than approximately 50 MW, variable-speed operation can be realized using conventional synchronous generators linked to the grid by a static frequency converter. For units larger than 50 MW, double-fed induction machines with a static frequency converter feeding the rotor are the preferred solution. This type of generator-motor is similar to the starting or "pony" motor on an older pump-turbine starting system. Wound Rotor Induction Motor (WRIM) or Double-Fed Induction Machine (DFIM) are terms used for induction machines that have normal synchronous machine slotted stators, but instead of salient pole-mounted field coils, the machines have slotted windings similar to the stator core with multiple phases (typically three) star connected with line coils connected to slip rings.

The stator of a DFIM is similar to the stators of conventional hydro generators. DFIMs are larger in size, have a higher moment of inertia, and smaller air gaps compared to salient pole machines of the same speed and power.

The rotor design is quite different, with fundamental changes to the slip rings, winding system and rotor rim. Figure 4-5 shows a Toshiba sketch comparison of the differences while Figure 4-6 shows a side-by-side comparison of a salient pole rotor with a variable-speed rotor. The rotor winding for a variable-speed rotor will be form-wound insulated to a voltage class that is typically lower than the stator-rated voltage. The rotor bars or coils will be subjected to high centrifugal force along with thermal and voltage stress, so winding manufacture requires special attention to materials and process to ensure longevity.

Figure 4-5. Comparison Sketch of Single-Speed and Variable-Speed Rotor

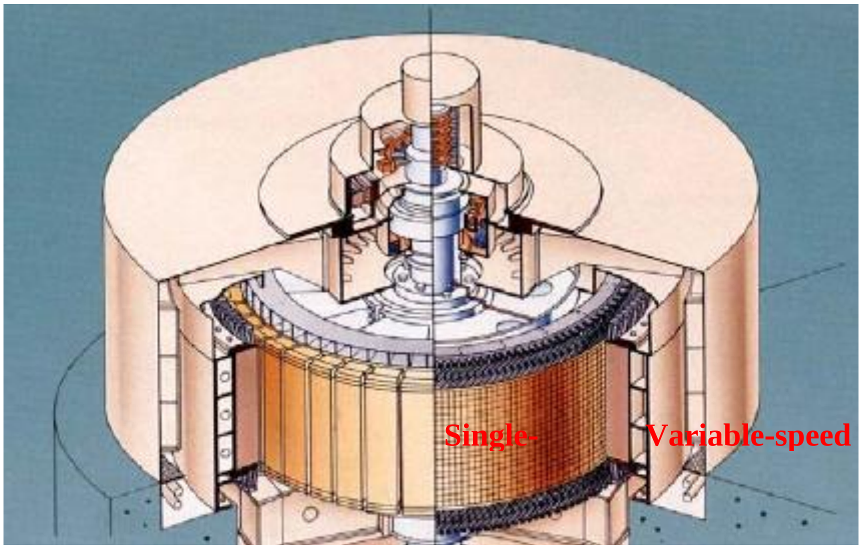


Figure 4-6. Single-Speed Rotor (Left) and Variable-Speed Rotor (Right)

Rotor end windings require robust centrifugal support, which must prevent undue bending of the rotor bars over all operating conditions. This support system requires additional axial space over salient pole synchronous designs. Rotor temperature rise, flux densities, air gap dimension, leakage flux, noise, vibration, resonance, mechanical and magnetic stability, and other design issues cannot be addressed in the same way as salient pole synchronous machine design. The WRIM will have a fixed number of rotor poles that can be selected at a different number than the number of pole groups in the stator (e.g., lower when applied to starting applications).

When the stator of the WRIM is connected to its three-phase system, the rotor magnetic field is synchronized to the system at a rotational speed determined by the number of pole groups in the stator. If the WRIM rotor is locked, the voltage induced in the rotor winding will be the open circuit rotor voltage at system frequency. In this arrangement, the WRIM is a transformer with stator voltage related to the rotor voltage by the design turns ratio.

Early converter systems used diodes, thyristors and Gate Turn Off (GTO) devices for rectifying and converting, but these systems had many drawbacks including low power factor at high loads, harmonic distortion, torque pulsation in the shaft, and high losses. More recent (i.e., within the past 20 years) Pulse Width Modulated (PWM) Voltage Source (VS) converters utilizing Insulated Gate Bipolar Transistor (IGBT) technology have been used in wound rotor applications, eliminating the drawbacks of the earlier power electronic methods. Most recently (i.e., within the past 5 years), an improved IGBT device, the Injection Enhanced Gate Transistor (IEGT) has proven to have extremely low power loss and a very small-sized controller for optimizing PWM vs. converters.

4.4 Major Equipment Suppliers

The industry leader in variable-speed technology is Toshiba. At present, all major manufacturers (Toshiba, Voith Hydro, Alstom, Andritz, Hitachi) have successfully demonstrated some degree of variable-speed technology in large-scale pumped storage operations either as a prime contractor or as part of a consortium of manufacturers. The extent of each manufacturer’s involvement is often not clear as a single project reference may be referenced by up to three suppliers.

4.5 Advantages and Disadvantages of Variable-Speed Technology

The primary advantages of variable-speed operation are as follows:

- ***Higher and flatter generating efficiency curve***. The unit is operated at slower speed at part load to improve part load and peak efficiency. Over the typical normal operating range of the unit, this could be about 0.5% to 2.0% improvement in generating efficiency. This also depends on the energy recovery from the wound rotor excitation system; nevertheless, there is some degree of efficiency improvement.

- ***Pump regulation***. Variable-speed operation would permit regulation in the pumping mode. For example, a unit capable of being operated as a pump with a variable-speed of +/- 7% from normal speed could potentially regulate power at +/- 20%. This is the primary advantage of variable-speed; however, at the extremes of pond elevation, it may not be possible to fully utilize this entire range because of generator-motor or pump-turbine limitations.
- ***Wider generating operating range***. A typical generating mode operating range is from about 60% of full load to 100% of full load because of concerns for rough operation and cavitation. Operation at lower speed raises part load efficiency and should allow the unit to operate over a wider range.
- ***Wider operating head range***: The typical head range of a single-speed pump-turbine used for preliminary studies is a minimum operating head of no less than 80% of the maximum operating head. Operation at wider head ranges will result in high cavitation levels or excessive unit submergence. Variable-speed operation allows a wider operating head range without cavitation and/or a higher unit setting as compared to a single-speed machine with a wide head range.
- ***Easier start-up process***: For larger single-speed pump-turbines, it can be problematic to obtain the large block of power necessary for pump starting. A variable-speed pump-turbine can be started at lower speed, reducing the power that is required to bring the pump on line. This advantage is normally only applicable for very large pumps where the input power can affect the grid performance.

The main disadvantage associated with variable-speed technology is the higher equipment costs and the cost of additional civil work to accommodate the physically larger variable-speed units in the powerhouse. The best information at present indicates that the incorporation of variable-speed units roughly doubles the cost of a typical generator-motor and excitation system. Powerhouse size and civil costs will also increase to handle additions to the powerhouse that will be required for the electronic equipment and additional transformers.

Table 4-1 provides a summary comparing the operational characteristics and advantages/disadvantages of single and variable-speed units for this particular project. This study assumes variable-speed units for the proposed pumped storage projects. Actual benefits will vary depending on specific site characteristics, which are described in the next chapter.

Table 4-1. Example Comparison of Primary Characteristics

Characteristic	Single-Speed	Variable-Speed
Proven Technology	45+ years - Worldwide	10+ years - Europe and Japan
Equipment Costs		Approximately 30% to 50% Greater
Powerhouse Size		Approximately 25% to 30% Greater
Powerhouse Civil Costs		Approximately 20% Greater
Project Schedule		Longer - Site Specific
O&M Costs		Greater
Operating Head Range	80% to 100% of Max. Head	70% to 100% of Max. Head
Generating Efficiency		Approximately 0.5% to 2% Greater
Power Adjustment Generation Mode	Approximately 60% to 100%	Approximately 50% to 100%
Power Adjustment Pump Mode	None	+/- 20%
Operating Characteristics		
Idle to Full Generation	Generally Less than 3 Minutes	Generally Less than 3 Minutes
100 Percent Pumping to 100 Percent Generation	Generally Less than 6 to 10 Minutes	Generally Less than 6 to 10 Minutes
100 Percent Generation to 100 Percent Pumping	Generally Less than 6 to 10 Minutes	Generally Less than 6 to 10 Minutes
Load Following	Seconds (i.e., 10 MW per Second)	Seconds (i.e., 10 MW per Second)
Reactive Power Changes	Instantaneously	Instantaneously
Automatic Frequency Control	No	Yes

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Chapter 5 Unit Refinement, Sizing, Capacity, and Energy Studies

5.1 Introduction

The project team performed the following unit refinement studies:

- Selection of Installed Capacity and Energy Storage
- Operating Characteristics and Efficiencies
- Physical Dimensions
- Operational Capabilities
- Ancillary Services

As described in the previous chapter, variable-speed units are proposed for the pumped storage projects. This chapter provides data on the units' potential operating ranges for energy arbitrage and ancillary service capabilities.

Energy arbitrage refers to the practice of utilizing electric energy during the lower priced, off-peak hours to pump water from an afterbay into a forebay reservoir. The water is then stored in the forebay for potential use. When energy prices are higher, water is released from the forebay through the turbines, and electricity is generated and sold at these higher prices. Energy arbitrage results in higher net income when the difference between on-peak and off-peak prices is greatest. Typically, energy prices are lowest during off-peak hours and are highest during the on-peak hours. Energy prices can also vary across days; prices on Sunday are typically lower relative to a weekday. All pump-turbine units have energy arbitrage capabilities. More energy is required for pumping a given amount of water uphill than can be recovered by releasing the same amount of water for generation. The ratio between energy used for pumping and the energy generated is called the turn-around efficiency and is generally in the range 70 to 85 percent, depending on design characteristics (ESA 2012). The following sections include pump and generation capacities and pump and generating efficiencies for the proposed units.

As described in Chapter 8, variable-speed units are more suitable for providing ancillary services than single-speed units, particularly regulation. Federal Energy Regulatory Commission (FERC) defined ancillary services as, "those services necessary to support the transmission of electric power from seller to the purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system" (FERC 1995). This chapter describes the unit capacity to provide the following services:

- **Spinning Reserves** - Reserved capacity provided by generating resources that are running (i.e., "spinning") with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours. Spinning Reserves are needed to maintain system frequency stability during emergency operating conditions and unanticipated variations in load.
- **Non-Spinning Reserves** - Generally, reserved capacity provided by generating resources that are available but not running. These generating resources must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then be able to run for at least two hours. Non-Spinning Reserves are needed to maintain system frequency stability during emergency conditions.
- **Regulation** - Reserved capacity provided by generating resources that are running and synchronized with the grid, so that the operating levels can be increased (incremented) or decreased (decremented) instantly through Automatic Generation Control (AGC) to allow continuous balance between generating resources and demand.

This chapter describes the operating capability of the proposed pump-turbine units to provide the above services.

5.2 Selection of Installed Capacity and Energy Storage

The pump-turbine selection assumes the use of variable-speed and power rating, as defined by studies of general plant configuration.

The motor-generator rating was selected to generate the rated power at 0.9 power factor. Table 5-1 summarizes the pump-turbine selection. Major pump-turbine dimensions are shown in Figure 5-1 and Table 5-2. This solution addresses all major features of the project, but will require more refinement as more constraints of the project are defined.

Table 5-1. Summary of Preliminary Characteristics

Characteristics	Units	Site				
		Yellowtail 5A	Seminoe 5A2	Seminoe 5A3	Seminoe 5C	Trinity 5G2A
Upper reservoir elevation						
Minimum	ft	5,100	7,100	7,250	7,165	3,015
Maximum	ft	5,260	7,290	7,440	7,300	3,105
Lower reservoir elevation						
Minimum	ft	3,580	6,290	6,290	6,290	2,200
Maximum	ft	3,657	6,357	6,357	6,357	2,370
Number of Units		4	4	4	2	4
Gross head range						
Minimum	ft	1,443	747	893	808	645
Maximum	ft	1,680	1,000	1,150	1,010	905
Generating head						
Minimum	ft	1,397	684	834	775	612
Maximum	ft	1,672	995	1,142	1,004	901
Total pump head						
Minimum	ft	1,454	753	901	814	650
Maximum	ft	1,712	1,009	1,166	1,021	911
Pump-turbine runner diameter	m	5.2	4.86	5.25	5.45	6.15
Synchronous speed	rpm	360	300	300	276.9	225
Speed variation	%	+/-5	+/-6	+/-5.0	+/-5.0	+/-5%
Rated generating output	MW	415	215	276	286	239
Motor-generator rating	MVA	461	239	307	318	284
Generating flow						
Minimum	cfs	638	556	621	732	730
Maximum	cfs	3,623	3,024	3,378	3,772	4,444
Pump flow						
Minimum	cfs	1,992	1,525	1,861	2,246	2,484
Maximum	cfs	3,379	3,077	3,441	3,948	4,483
Unit CL elevation	ft	3,310	6,085	6,085	6,110	2,070

Figure 5-1. Major Pump-Turbine Dimensions

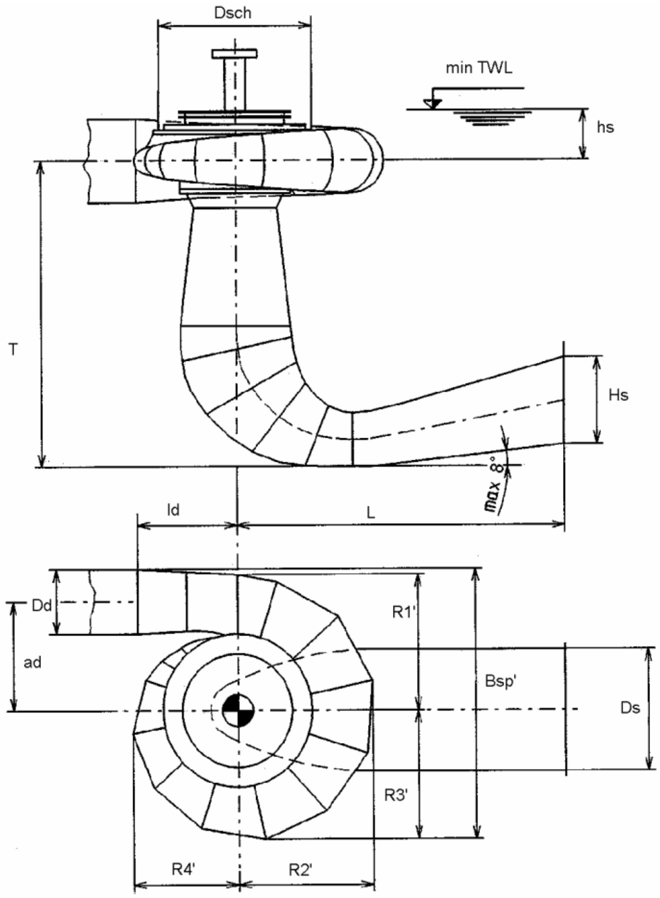


Table 5-2. Preliminary Pump-Turbine Dimensions (in Feet)

Characteristics	Units	Site				
		Yellowtail 5A	**Seminoe 5A2**	**Seminoe 5A3**	**Seminoe 5C**	**Trinity 5G2A**
Pump Discharge Diameter	D	17.1	15.9	17.2	17.9	20.2
Pump Inlet Diameter	Do	9.2	9.0	9.4	10.0	11.1
Minimum Suction Head	hs	270	205	205	180	130
Spiral Case Inlet Diameter	Dd	9.3	9.2	9.6	10.7	11.3
Spiral Case	R1	22.7	21.2	22.9	23.8	26.8
Spiral Case	R2	21.5	20.1	21.7	22.5	25.4
Spiral Case	R3	20.1	18.8	20.3	21.1	23.8
Spiral Case	R4	18.6	17.4	18.8	19.5	22.0
Draft Tube Depth	T	35.3	34.4	36.2	41.9	42.5
Draft Tube Length	L	74.8	89.3	79.3	97.6	101.1
Draft Tube Diameter	Ds	18.0	21.0	19.0	23.0	14.4

5.3 Yellowtail 5A Unit Operating Characteristics

This section presents the operating range of the variable-speed pump-turbine units using the information contained within this report to maximize the operational flexibility necessary to integrate intermittent renewable generating resources.

5.3.1 Yellowtail 5A Operating Range

Figures 5-2 and 5-3 show the operating range of the solution outlined in Table 5-1, using speed variation of ±5%. Figure 5-4 shows estimates of generating performance. Analogous fields of pumping operation are shown in Figures 5-5 and 5-6.

Figure 5-2. Yellowtail 5A - Typical Range of Power in Generating Mode

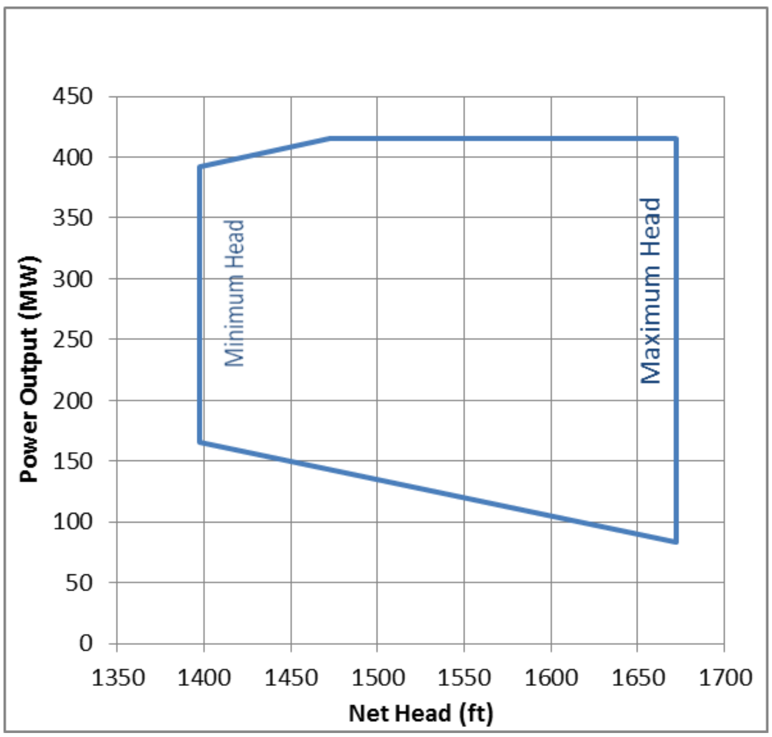


Figure 5-3. Yellowtail 5A - Typical Range of Flow in Generating Mode

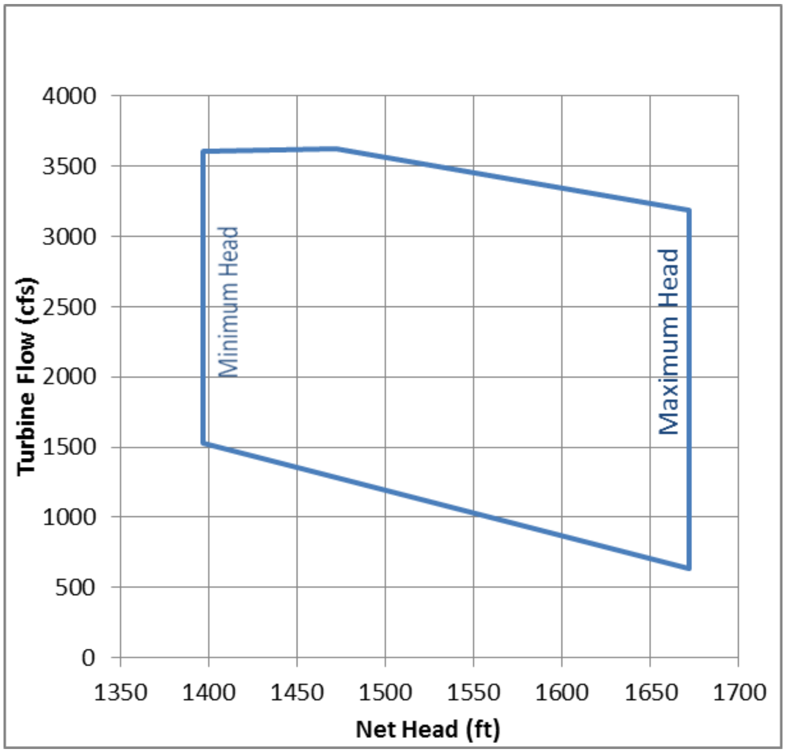


Figure 5-4. Yellowtail 5A - Estimated Generating Performance Curves

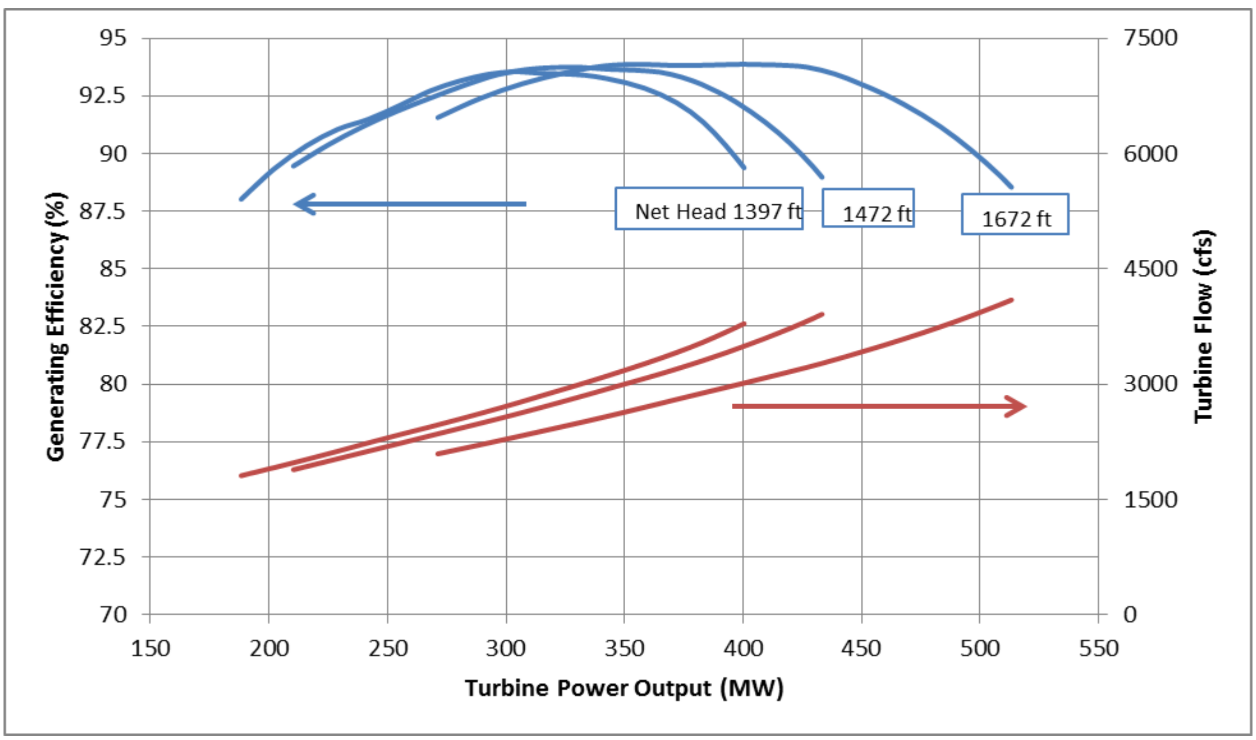


Figure 5-5. Yellowtail 5A - Typical Power Range in Pumping Mode

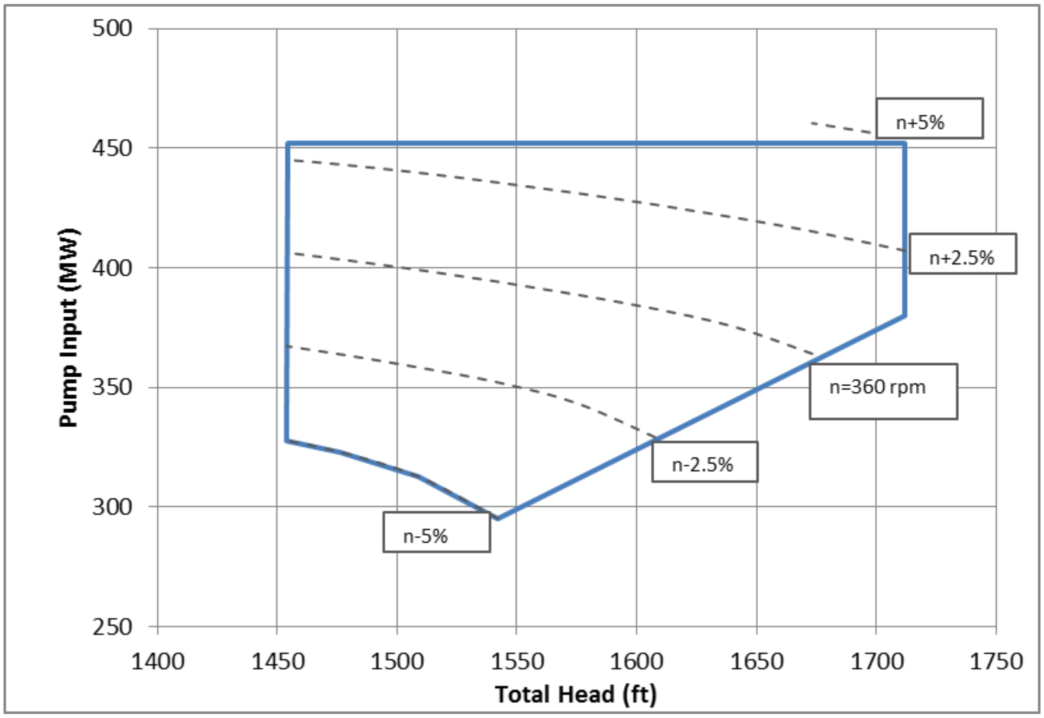
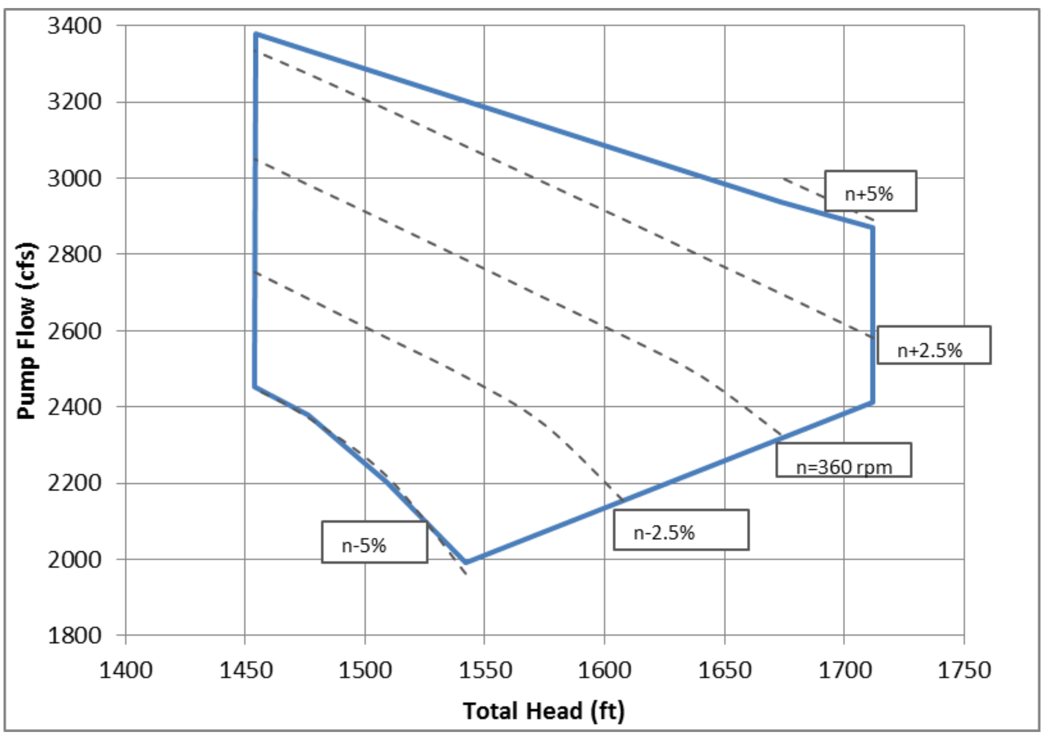


Figure 5-6. Yellowtail 5A - Typical Range of Pumping Flow



5.3.2 Yellowtail 5A Estimate of Unit Efficiencies

Tables 5-3 and 5-4 list pumping and generating efficiencies.

Table 5-3. Yellowtail 5A Pumping Efficiencies

Component	Efficiency
Pump	92.5%
Motor	98.5%
Transformer	99.0%
Total pumping efficiency	90.2%

Table 5-4. Yellowtail 5A Generating Efficiencies

Flow (cfs)	Turbine	Generator	Transformer	Total Generating Efficiency
1,000	75.0%	98.5%	99.0%	73.1%
1,500	86.0%	98.5%	99.0%	83.9%
2,000	90.4%	98.5%	99.0%	88.1%
2,500	93.2%	98.5%	99.0%	90.9%
3,000	93.6%	98.5%	99.0%	91.3%
3,500	92.0%	98.5%	99.0%	89.7%
4,000	88.2%	98.5%	99.0%	86.0%
4,200	86.2%	98.5%	99.0%	84.1%

5.3.3 Yellowtail 5A Operational Capabilities

5.3.3.1 Incremental and Decremental Reserves

Utilizing advanced variable-speed technology, Yellowtail Option 5A can provide between 1,438 MW and 1,575 MW of incremental reserves in generation mode (Table 5-6). The technology gives the plant the capability of bringing each unit from standstill to full load generation in less than three minutes. Each unit can generate between a minimum of 85 to 166 MW to a maximum of 415 MW (depending on the starting head differential), allowing it to provide between 235 MW to 330 MW of incremental reserves individually (Table 5-5). As each additional unit is brought online, 415 MW of capacity and between 235 MW and 330 MW of incremental reserve capability can be added. By bringing units online and offline, and utilizing the output flexibility of each unit, the plant can provide between 1,438 and 1,575 MW of incremental reserves along a continuum. This process is described as follows, and illustrated in Figure 5-7.

Table 5-5. Yellowtail 5A - Summary of Preliminary Unit Market Products

	Generate Mode					Pump Mode				
	Min MW	**Max MW**	**Incremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**
@ Min. Head	166	401	235	Full range of Unit Operations in < 3 Min	Full range of Unit Operations in < 6 Min	328	452	124	Full range of Unit Operations in < 4 Min	Full range of Unit Operations in < 8 Min
@ Max Head	85	415	330			380	452	72		

Table 5-6. Yellowtail 5A - Summary of Preliminary Total Station Market Products

	Generate Mode			Pump Mode		
	Min MW	**Max MW**	**Incremental Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**
@ Min. Head	166	1604	1438	328	1808	1480
@ Max Head	85	1660	1575	380	1808	1428

Figure 5-7. Yellowtail 5A Range of Generating Power Output

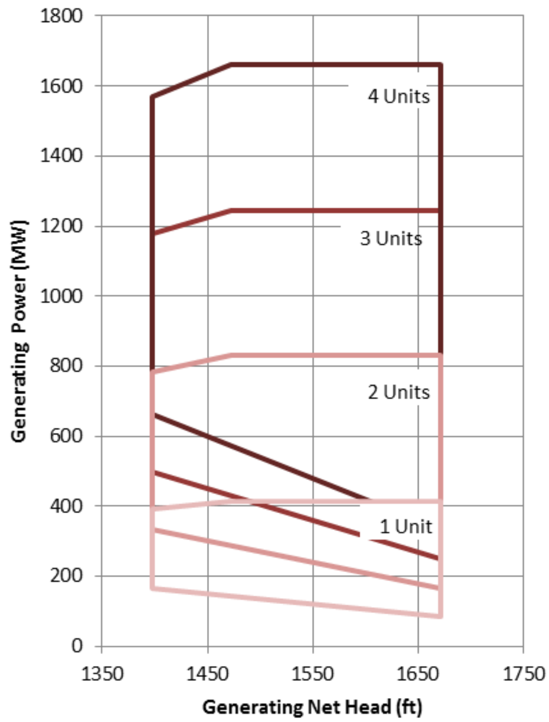
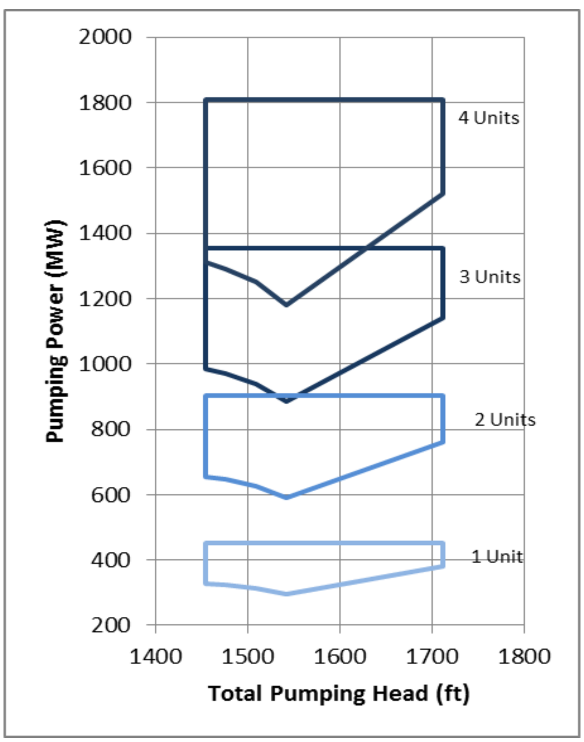


Figure 5-8. Yellowtail 5A Range of Pumping Power Input



- **One-Unit Generation -** As the first unit is brought online, it has the ability to generate between 85 MW and 415 MW. As such, 235 MW (i.e., the difference between the minimum and maximum load generation) of incremental reserves can be provided. The actual generation output is dependent on the starting head differential of the upper and lower reservoirs.
- **Two-Unit Generation -** When a second unit is brought online, both units must generate at least 85 MW, giving the two units a total minimum output of 170 MW. In two-unit generation, the plant can generate between 170 MW and 830 MW.
- **Three-Unit Generation –** When a third unit is brought online, all units must generate at least 85 MW but no more than 415 MW, giving the three units a minimum output of 255 MW and maximum output of 1,245 MW.
- **Four-Unit Generation –** When the final unit is brought online, the total minimum output of the plant is 340 MW, and the total maximum output is 1,660 MW.

In pumping mode, it is expected that each unit will be capable of starting at a minimum input power of 295 MW to 328 MW (depending on the head, see Figure 5-6) at low speed and rapidly ramping to 450 MW at high speed as necessary to support grid operations. From synchronous condense operation, each pump can reach full load in less than four minutes. From a cold start, each unit can reach full load operation in less than eight minutes. Similar to the continuum of incremental reserves achievable in generation mode, the plant is able to provide a significant range of decremental reserves in pumping mode by coupling each unit's 295 MW to 450 MW input range with the ability to operate more or less units (Figure 5-8).

It is possible to pump using 295 MW to 450 MW, and 590 MW to 1,800 MW of power and because units can reach full load in a relatively short period of time, this power input range can be used to provide decremental reserves.

5.3.3.2 Spinning and Non-Spinning Reserves

The units will have the capability to be in a constant spin state. When not generating or absorbing power, the units can be in synchronous condense mode and be eligible for spinning reserves consideration.

5.3.3.3 Frequency Regulation

The units will have regulation capability (in a fly-wheel type of response) in both generator and pumping mode. The power electronics associated with variable-speed technology provides less than a cycle response time.

5.3.3.4 Generating and Pumping Flexibility

As currently configured, with only one power tunnel, the four units must be moving water in the same direction. In other words, if one unit is in generation mode, the remaining three units can provide additional generation capability, or be in synchronous condense mode (either generating or pumping mode). The project, as currently conceived, does not have the capability to allow simultaneous generating and pumping.

5.3.3.5 Rapid Response

Variable-speed pump-turbines are particularly suitable to work with in electrical systems with a large percentage of highly and randomly fluctuating power sources, such as solar and wind.

Slow power changes in generating mode are achieved through normal loading of the pump-turbine, controlled by the governor. Its speed is limited by hydraulic transients (water hammer). The plant can be designed to improve in this respect. Properly positioned and sized surge tanks or chambers are the primary measure to achieve that.

Another limiting factor is the power ramp-up speed, to limit stresses in the motor-generator due to the rapid heating of the coils. This also could be dealt with by proper design measures.

Rapid loading from standby mode will require the units to be in spinning reserve (i.e. synchronized in the generating mode, with the runner rotating in air). All features necessary for the spinning reserve are normally incorporated in a pump turbine design.

As stated earlier, single-speed pump-turbines are not capable of adjusting power in the pump mode. The speed of changing the input power with variable-speed is dictated by hydraulic transients. With a properly designed power plant, the full range of adjustment could be reached within 10 to 20 seconds.

Variable-speed pump-turbines also offer a possibility of much more rapid response to power fluctuations by tapping to the kinetic energy of their rotating masses. By changing the speed, the unit can absorb or release power to the grid, this way effectively suppressing frequency fluctuations. The time scale of this type of response is few seconds and is sufficient to address needs of power systems with large percentage of randomly changing renewable sources.

In addition, the variable-speed pump-turbines can very rapidly control reactive power, achieving this way a very quick and effective voltage regulation, equivalent to the use of Static Var Compensators.

5.4 Seminoe 5A2 Unit Operating Characteristics

5.4.1 Seminoe 5A2 Operating Range

Figures 5-9 and 5-10 show the operating range of the solution outlined in Table 5-1, using speed variation of ±6.0%. Figure 5-11 gives estimates of the generating performance. Analogous fields of pumping operation are shown in Figures 5-12 and 5-13.

Figure 5-9. Seminoe 5A2 - Typical Range of Power in Generating Mode

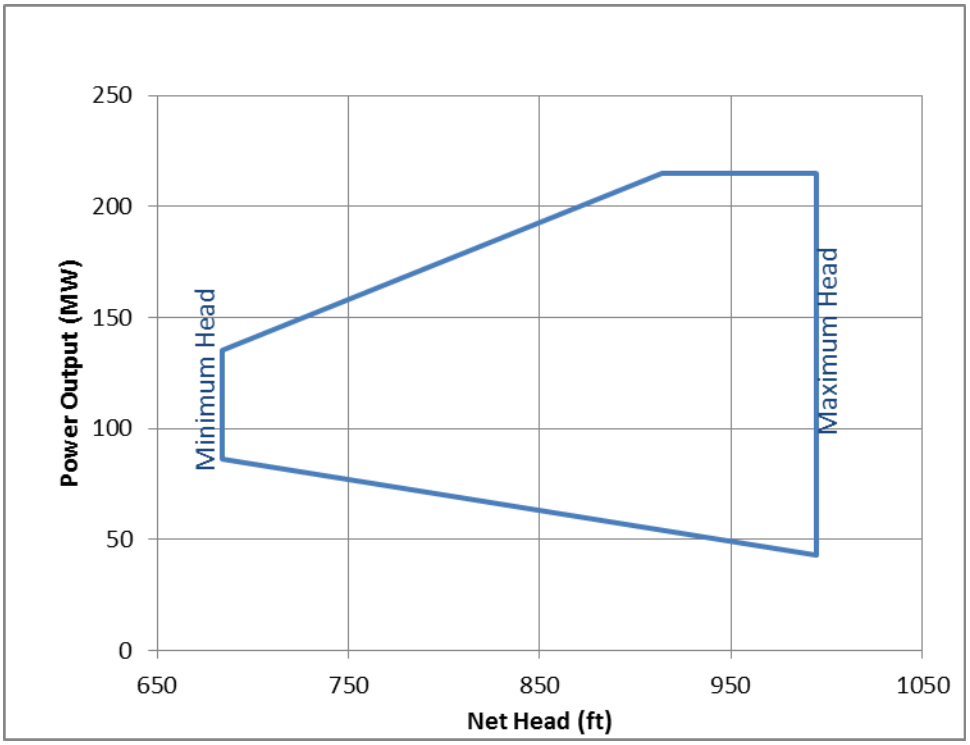


Figure 5-10. Seminoe 5A2 - Typical Range of Flow in Generating Mode

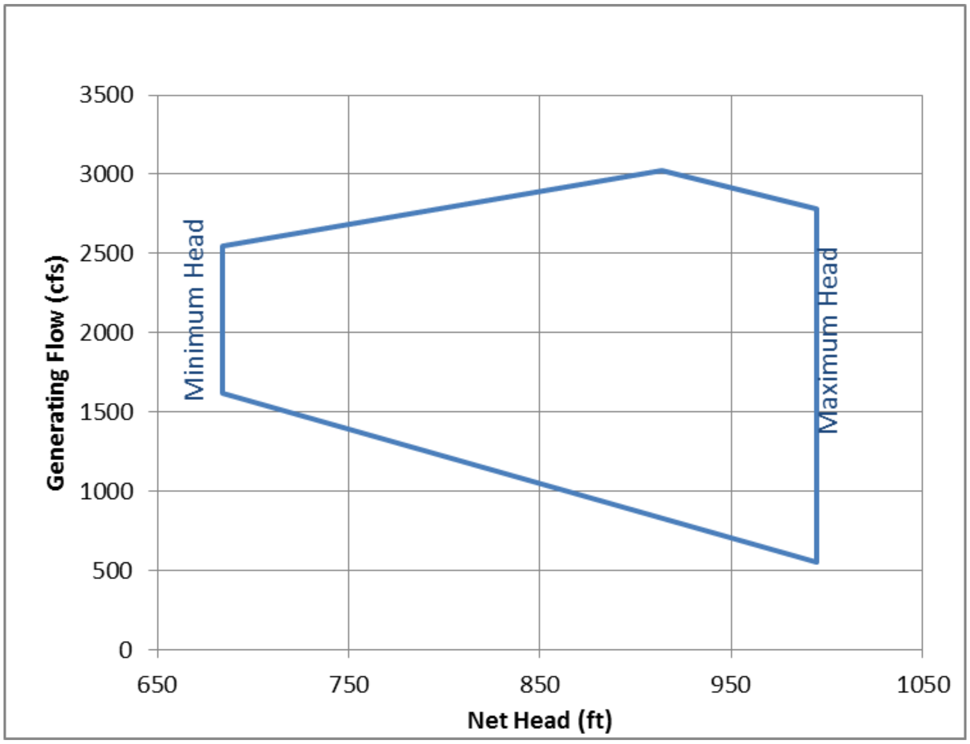


Figure 5-11. Seminoe 5A2 - Estimated Generating Performance Curves

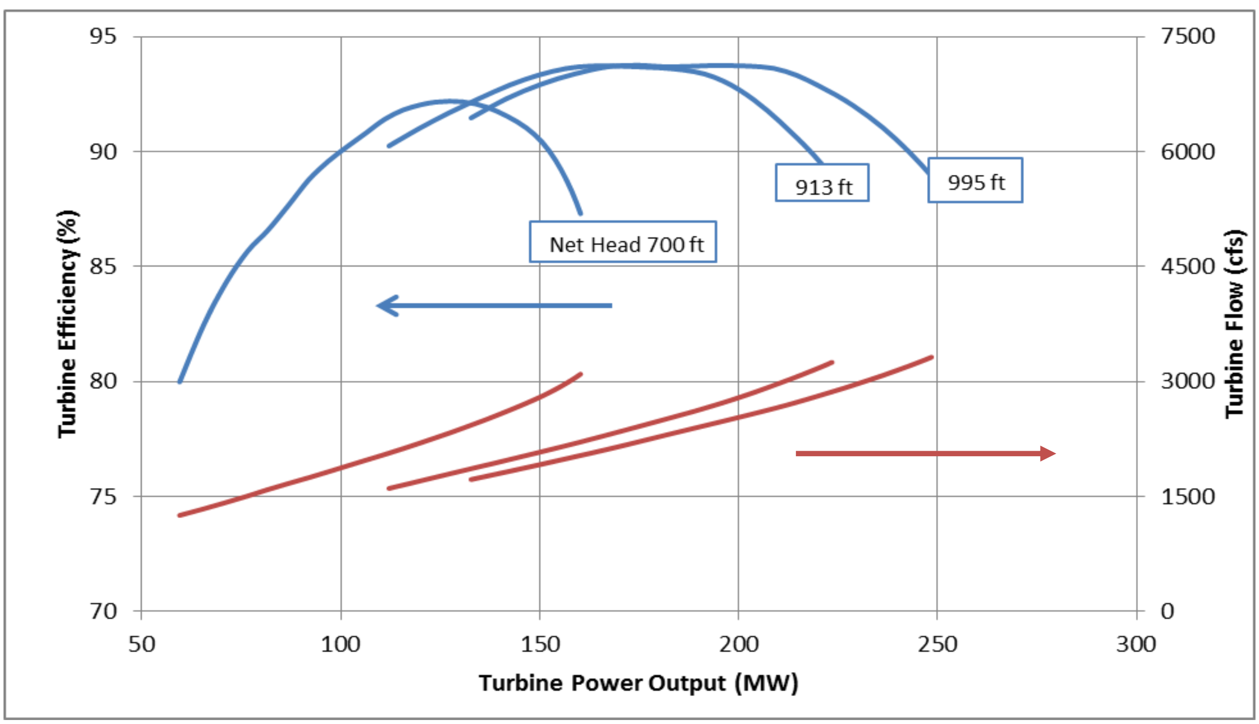


Figure 5-12. Seminoe 5A2 - Typical Power Range in Pumping Mode

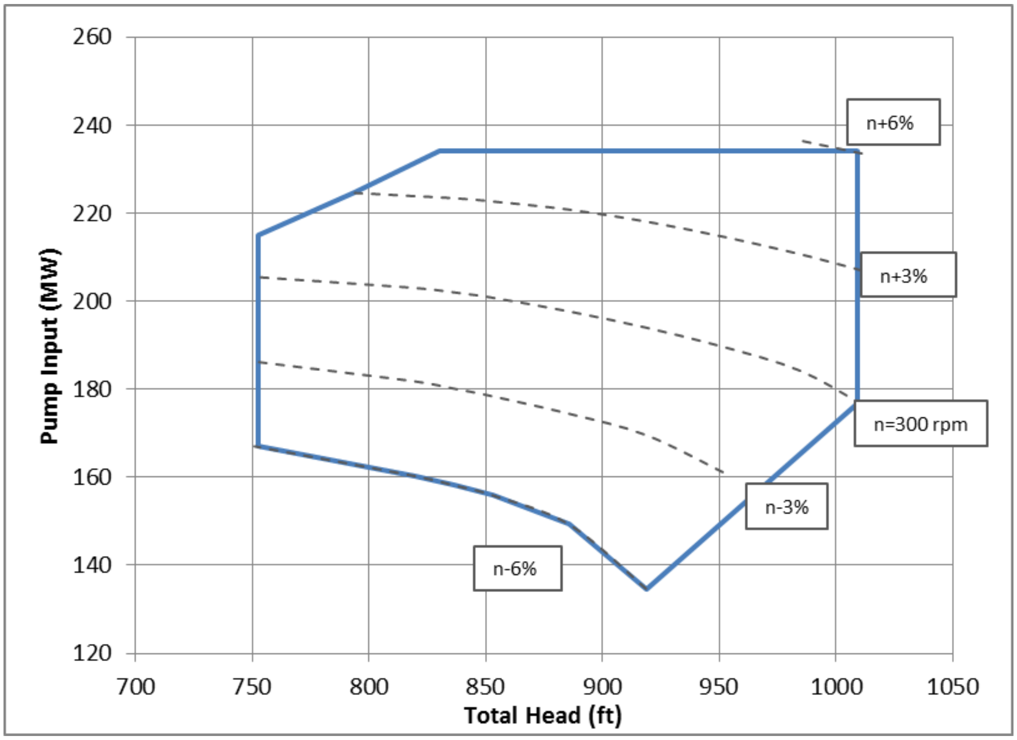
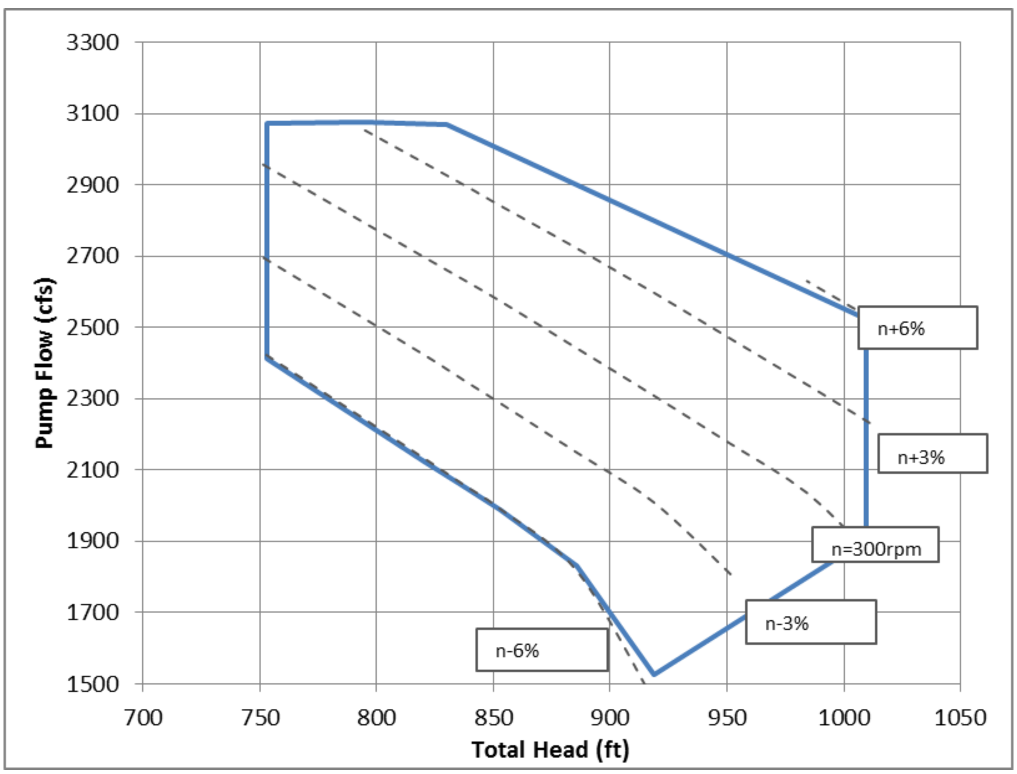


Figure 5-13. Seminoe 5A2 - Typical Range of Pumping Flow



5.4.2 Seminoe 5A2 Estimate of Unit Efficiencies

Tables 5-7 and 5-8 list pumping and generating efficiencies.

Table 5-7. Seminoe 5A2 Pumping Efficiencies

Component	Efficiency
Pump	92.4%
Motor	98.5%
Transformer	99.0%
Total Pumping Efficiency	90.1%

Table 5-8. Seminoe 5A2 Generating Efficiencies

Flow (cfs)	Turbine	Generator	Transformer	Total Generating Efficiency
1,000	82.0%	98.5%	99.0%	80.0%
1,500	90.0%	98.5%	99.0%	87.8%
2,000	93.0%	98.5%	99.0%	90.7%
2,500	93.6%	98.5%	99.0%	91.3%
3,000	91.2%	98.5%	99.0%	88.9%
3,200	89.4%	98.5%	99.0%	87.2%

5.4.3 Seminoe 5A2 Operational Capabilities

5.4.3.1 Incremental and Decremental Reserves

Utilizing advanced variable-speed technology, Seminoe Option 5A2 can provide between 456 MW and 817 MW of incremental reserves in generation mode (Table 5-10). The technology gives the plant the capability of bringing each unit from standstill to full load generation in less than three minutes. Each unit can generate between a minimum of 43 to 86 MW to a maximum of 215 MW (depending on the starting head differential), allowing it to provide between 49 MW to 172 MW of incremental reserves individually (Table 5-9). As each additional unit is brought online, 215 MW of capacity and between 49 MW to 172 MW of incremental reserve capability can be added. By bringing units online and offline, and utilizing the output flexibility of each unit, the plant can provide between 456 and 860 MW of incremental reserves along a continuum. This process is described as follows, and illustrated in Figure 5-14.

Table 5-9. Seminoe 5A2 - Summary of Preliminary Unit Market Products

	Generate Mode					Pump Mode				
	Min MW	**Max MW**	**Incremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**
@ Min. Head	86	135	49	Full range of Unit Operations in < 3 Min	Full range of Unit Operations in < 6 Min	167	215	48	Full range of Unit Operations in < 4 Min	Full range of Unit Operations in < 8 Min
@ Max Head	43	215	172			177	234	57		

Table 5-10. Seminoe 5A2 - Summary of Preliminary Total Station Market Products

	Generate Mode			Pump Mode		
	Min MW	**Max MW**	**Incremental Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**
@ Min. Head	86	542	456	167	860	693
@ Max Head	43	860	817	177	936	760

Figure 5-14. Seminoe 5A2 Range of Generating Power Output

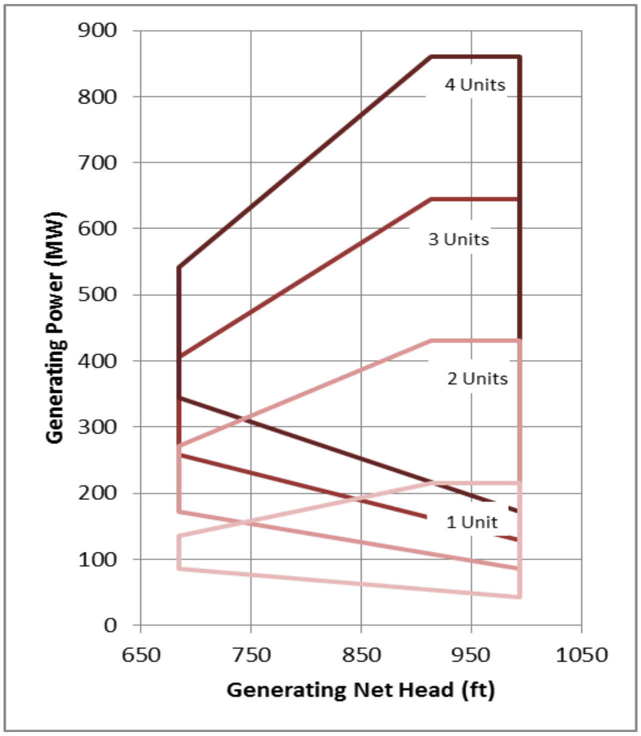
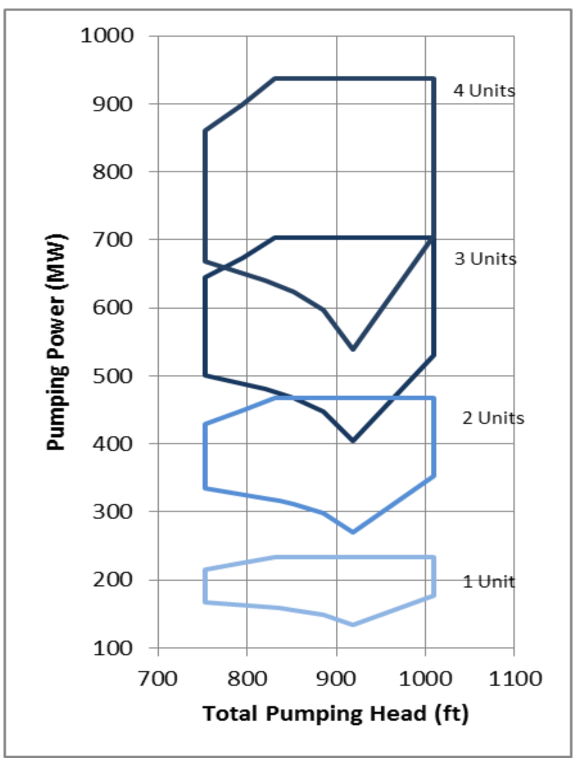


Figure 5-15. Seminoe 5A2 Range of Pumping Power Input



- **One-Unit Generation -** As the first unit is brought online, it has the ability to generate between 43 MW and 215 MW. As such, 172 MW (i.e., the difference between the minimum and maximum load generation) of incremental reserves can be provided. The actual generation output is dependent on the starting head differential of the upper and lower reservoirs.
- **Two-Unit Generation -** When a second unit is brought online, both units must generate at least 43 MW, giving the two units a total minimum output of 86 MW. In two-unit generation, the plant can generate between 86 MW and 430 MW.
- **Three-Unit Generation** – When a third unit is brought online, all units must generate at least 43 MW but no more than 215 MW, giving the three units a minimum output of 129 MW and maximum output of 645 MW.
- **Four-Unit Generation** – When the final unit is brought online, the total minimum output of the plant is 172 MW, and the total maximum output is 860 MW.

In pumping mode, it is expected that each unit will be capable of starting at a minimum input power of 134 MW to 167 MW (depending on the head; see Figure 5-12) at low speed and rapidly ramping to 234 MW at high speed as necessary to support grid operations. From synchronous condense operation, each pump can reach full load in less than four minutes. From a cold start, each unit can reach full load operation in less than eight minutes. Similar to the continuum of incremental reserves achievable in generation mode, the plant is able to provide a significant range of decremental reserves in pumping mode by coupling each unit’s 134 MW to 234 MW input range with the ability to operate more or less units (Figure 5-15).

It is possible to pump using 134 MW to 234 MW, and 538 MW to 936 MW of power and because units can reach full load in a relatively short period of time, this power input range can be used to provide decremental reserves.

5.4.3.2 Spinning and Non-Spinning Reserves

Refer to Section 5.3.3.2.

5.4.3.3 Frequency Regulation

Refer to Section 5.3.3.3.

5.4.3.4 Generating and Pumping Flexibility

Refer to Section 5.3.3.4.

5.4.3.5 Rapid Response

Refer to Section 5.3.3.5.

5.5 Seminoe 5A3

5.5.1 Seminoe 5A3 Operating Range

The operating range of a variable-speed pump-turbine requires to be optimized, using constraints of the installation and the desired flexibility of operation. Figures 5-16 and 5-17 show the operating range of the solution outlined in Table 5-1, using speed variation of ±5.0%. Figure 5-18 gives estimates of the generating performance. Analogous fields of pumping operation are shown in Figures 5-19 and 5-20.

Figure 5-16. Seminoe 5A3 - Typical Range of Power in Generating Mode

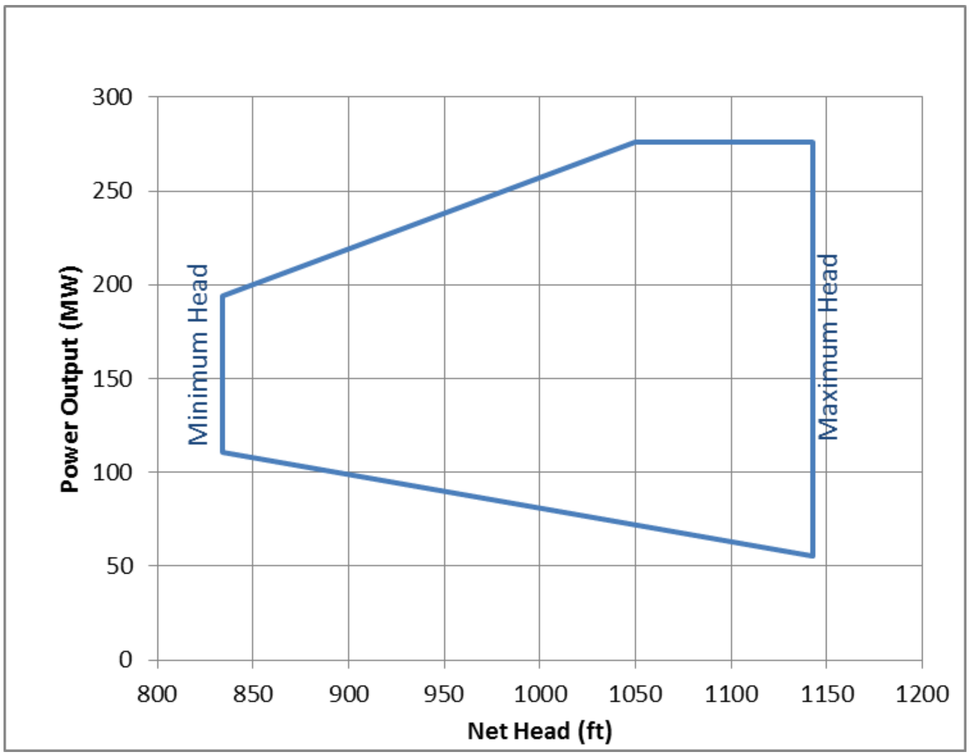


Figure 5-17. Seminoe 5A3 - Typical Range of Flow in Generating Mode

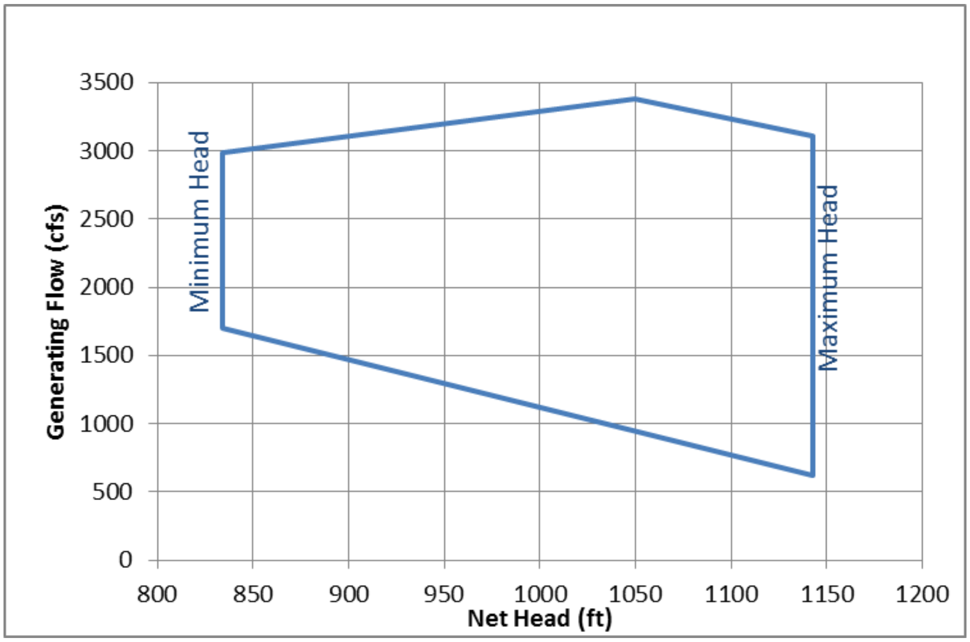


Figure 5-18. Seminoe 5A3 - Estimated Generating Performance Curves

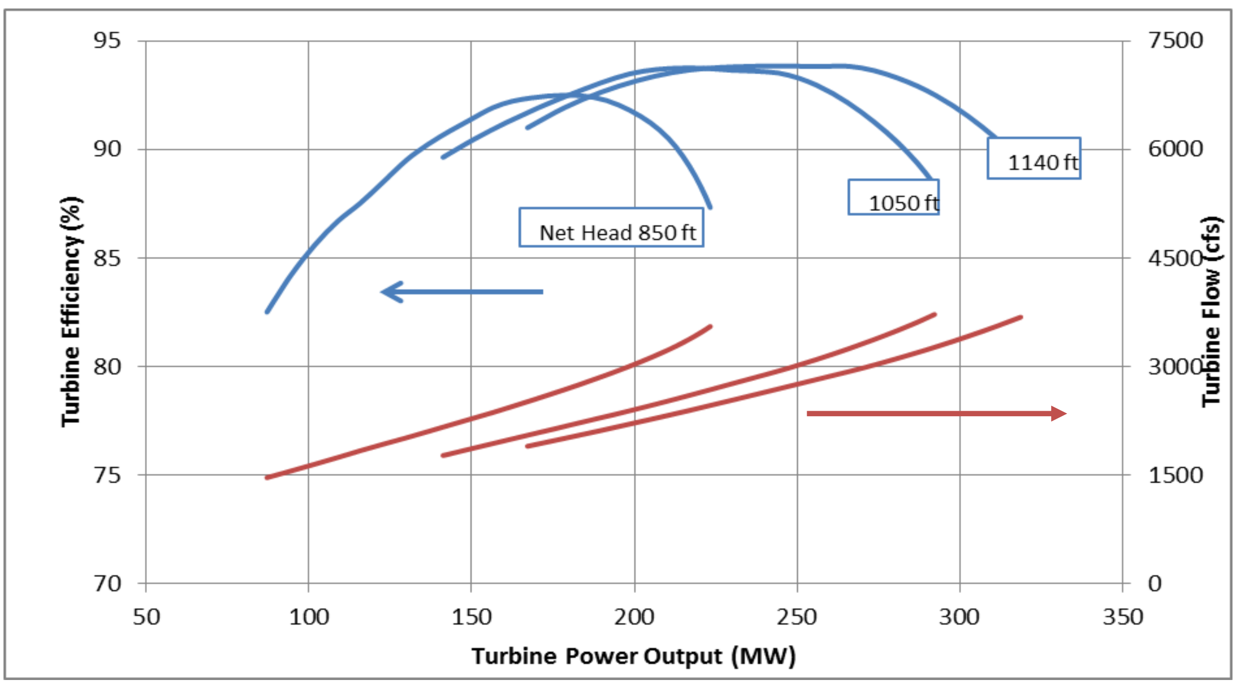


Figure 5-19. Seminoe 5A3 - Typical Power Range in Pumping Mode

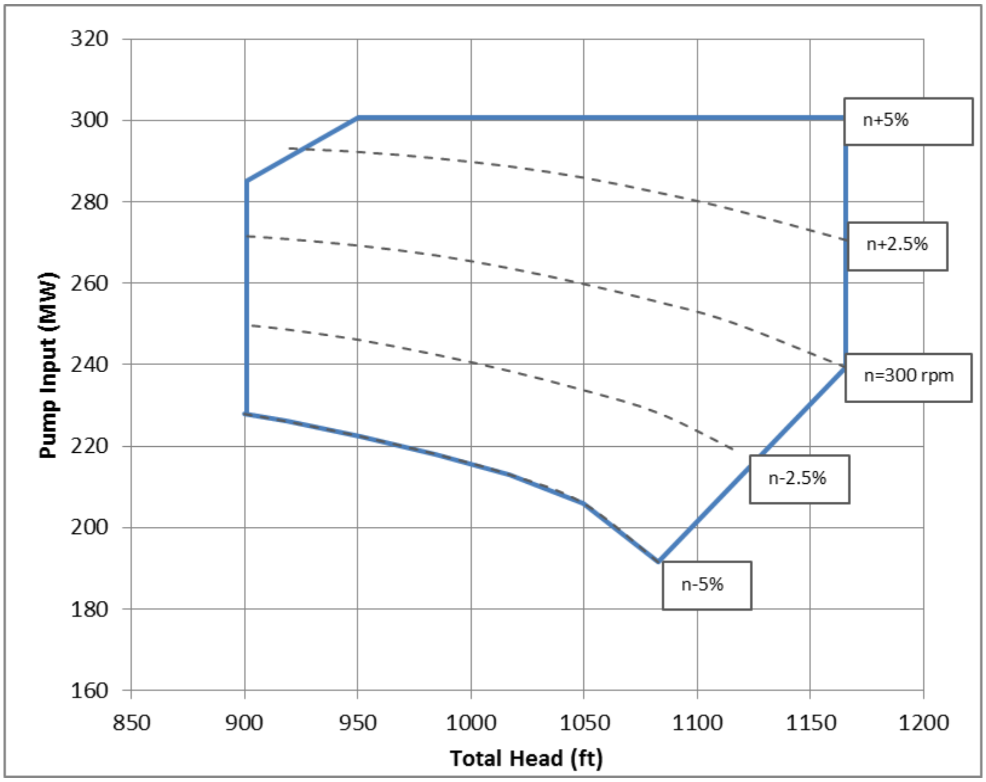
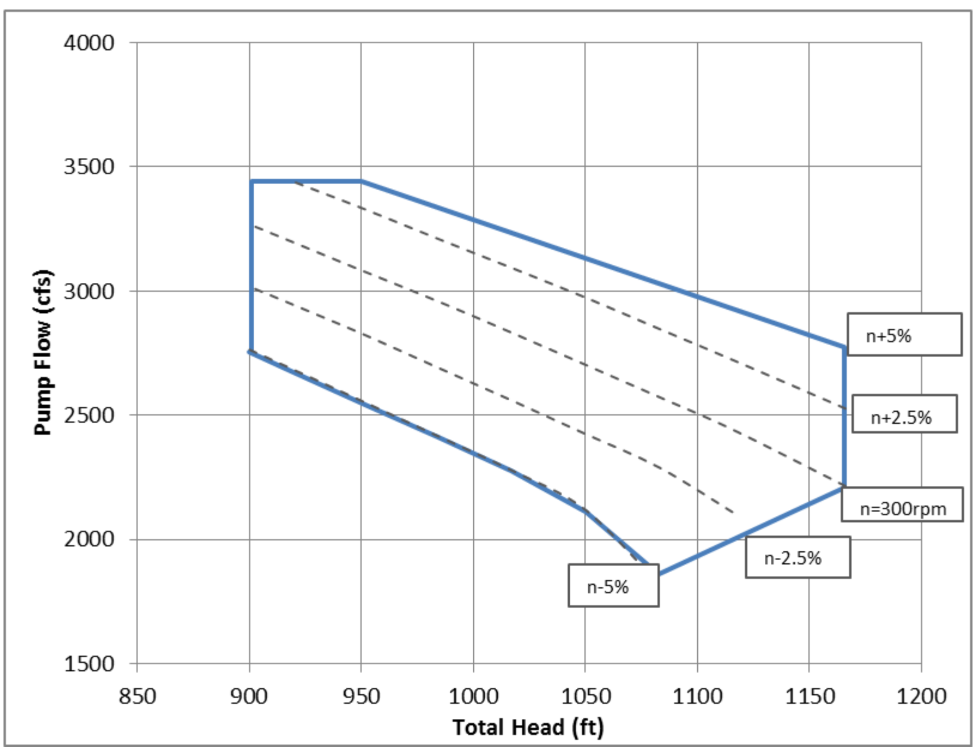


Figure 5-20. Seminoe 5A3 - Typical Range of Pumping Flow



5.5.2 Seminoe 5A3 Estimate of Unit Efficiencies

Tables 5-11 and 5-12 list pumping and generating efficiencies.

Table 5-11. Seminoe 5A3 Pumping Efficiencies

Component	Efficiency
Pump	92.5%
Motor	98.5%
Transformer	99.0%
Total pumping efficiency	90.2%

Table 5-12. Seminoe 5A3 Generating Efficiencies

Flow (cfs)	Turbine	Generator	Transformer	Total Generating Efficiency
1,000	82.0%	98.5%	99.0%	80.0%
1,500	86.0%	98.5%	99.0%	83.9%
2,000	91.4%	98.5%	99.0%	89.1%
2,500	93.7%	98.5%	99.0%	91.4%
3,000	93.4%	98.5%	99.0%	91.0%
3,500	90.3%	98.5%	99.0%	88.1%

5.5.3 Seminoe 5A3 Operational Capabilities

5.5.3.1 Incremental and Decremental Reserves

Utilizing advanced variable-speed technology, Seminoe Option 5A3 can provide between 665 MW and 1,049 MW of incremental reserves in generation mode (Table 5-14). The technology gives the plant the capability of bringing each unit from standstill to full load generation in less than three minutes. Each unit can generate between a minimum of 55 to 110 MW to a maximum of 276 MW (depending on the starting head differential), allowing it to provide between 84 MW to 221 MW of incremental reserves individually (Table 5-13). As each additional unit is brought online, 276 MW of capacity and between 84 MW to 221 MW of incremental reserve capability can be added. By bringing units online and offline, and utilizing the output flexibility of each unit, the plant can provide between 665 and 1,049 MW of incremental reserves along a continuum. This process is described as follows, and illustrated in Figure 5-21.

Table 5-13. Seminoe 5A3 - Summary of Preliminary Unit Market Products

	Generate Mode					Pump Mode				
	Min MW	**Max MW**	**Incremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**
@ Min. Head	110	194	84	Full range of Unit Operations in < 3 Min	Full range of Unit Operations in < 6 Min	226	285	59	Full range of Unit Operations in < 4 Min	Full range of Unit Operations in < 8 Min
@ Max Head	55	276	221			239	301	61		

Table 5-14. Seminoe 5A3 - Summary of Preliminary Total Station Market Products

	Generate Mode			Pump Mode		
	Min MW	**Max MW**	**Incremental Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**
@ Min. Head	110	776	665	226	1,140	914
@ Max Head	55	1,104	1,049	239	1,202	963

Figure 5-21. Seminoe 5A3 Range of Generating Power Output

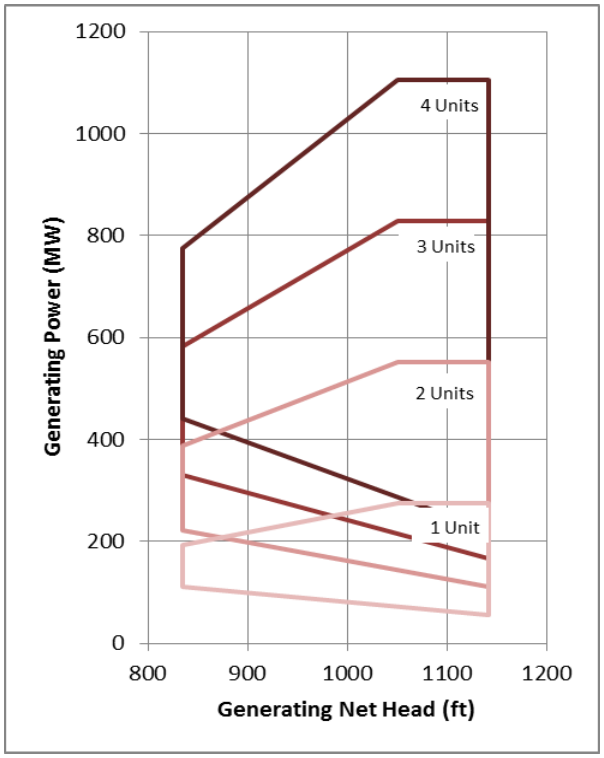
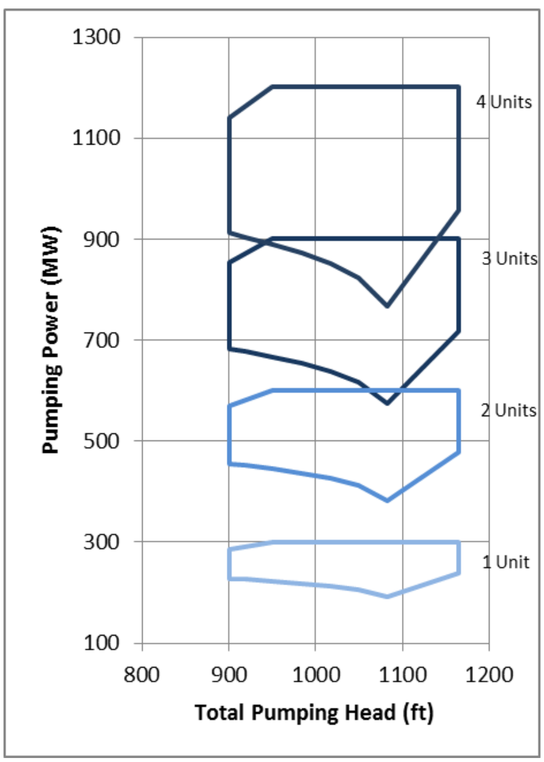


Figure 5-22. Seminoe 5A3 Range of Pumping Power Input



- **One-Unit Generation -** As the first unit is brought online, it has the ability to generate between 55 MW and 276 MW. As such, 221 MW (i.e., the difference between the minimum and maximum load generation) of incremental reserves can be provided. The actual generation output is dependent on the starting head differential of the upper and lower reservoirs.
- **Two-Unit Generation -** When a second unit is brought online, both units must generate at least 55 MW, giving the two units a total minimum output of 110 MW. In two-unit generation, the plant can generate between 110 MW and 552 MW.
- **Three-Unit Generation –** When a third unit is brought online, all units must generate at least 55 MW but no more than 276 MW, giving the three units a minimum output of 165 MW and maximum output of 828 MW.
- **Four-Unit Generation –** When the final unit is brought online, the total minimum output of the plant is 220 MW, and the total maximum output is 1,104 MW.

In pumping mode, it is expected that each unit will be capable of starting at a minimum input power of 191 MW to 226 MW (depending on the head; see Figure 5-19) at low speed and rapidly ramping to 301 MW at high speed as necessary to support grid operations. From synchronous condense operation, each pump can reach full load in less than four minutes. From a cold start, each unit can reach full load operation in less than eight minutes. Similar to the continuum of incremental reserves achievable in generation mode, the plant is able to provide a significant range of decremental reserves in pumping mode by coupling each unit's 191 MW to 301 MW input range with the ability to operate more or less units (Figure 5-22).

It is possible to pump using 191 MW to 301 MW, and 766 MW to 1,204 MW of power and because units can reach full load in a relatively short period of time, this power input range can be used to provide decremental reserves.

5.5.3.2 Spinning and Non-Spinning Reserves

Refer to Section 5.3.3.2.

5.5.3.3 Frequency Regulation

Refer to Section 5.3.3.3.

5.5.3.4 Generating and Pumping Flexibility

Refer to Section 5.3.3.4.

5.5.3.5 Rapid Response

Refer to Section 5.3.3.5.

5.6 Seminoe 5C Unit Operating Characteristics

5.6.1 Seminoe 5C Operating Range

The operating range of a variable-speed pump-turbine requires to be optimized, using constraints of the installation and the desired flexibility of operation. Figures 5-23 and 5-24 show the operating range of the solution outlined in Table 5-1, using speed variation of ±5.0%. Figure 5-25 gives estimates of the generating performance. Analogous fields of pumping operation are shown in Figures 5-26 and 5-27.

Figure 5-23. Seminoe 5C - Typical Range of Power in Generating Mode

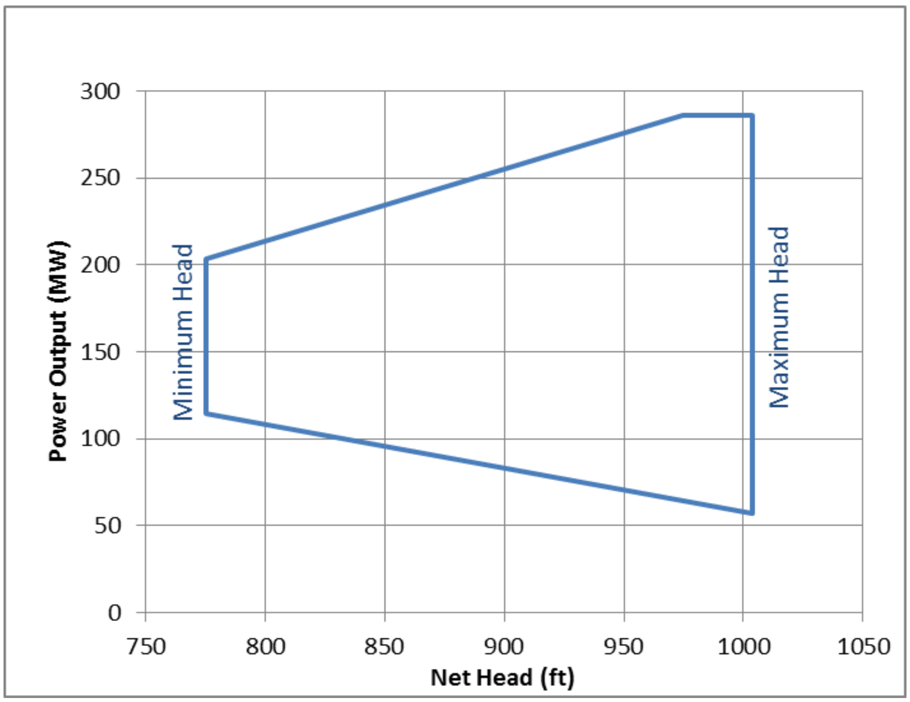


Figure 5-24. Seminoe 5C - Typical Range of Flow in Generating Mode

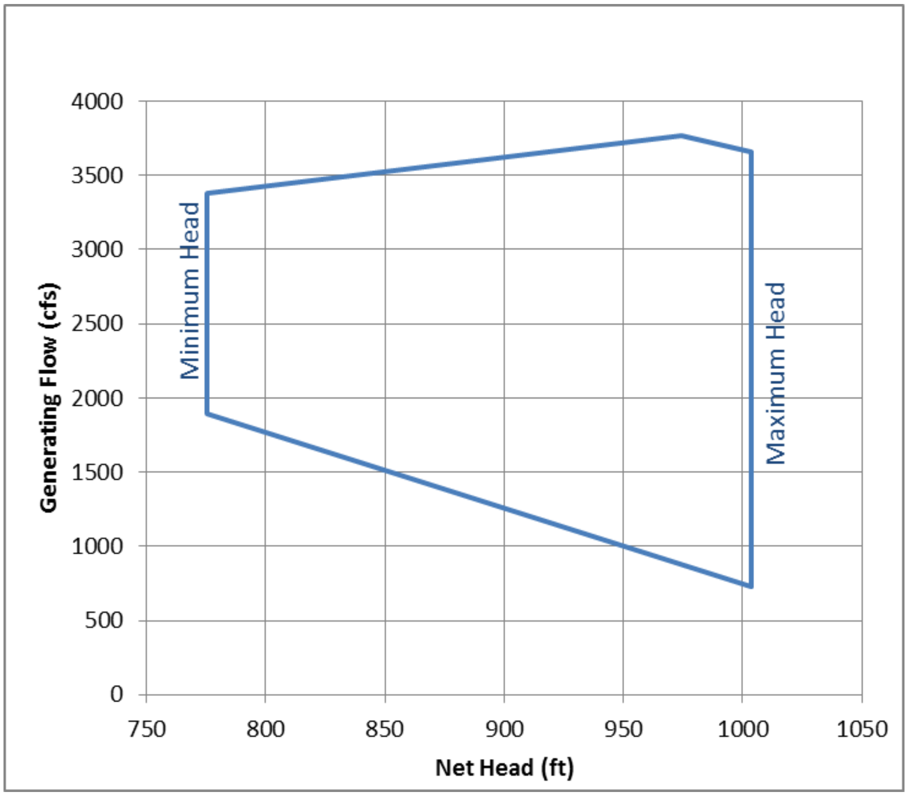


Figure 5-25. Seminoe 5C - Estimated Generating Performance Curves

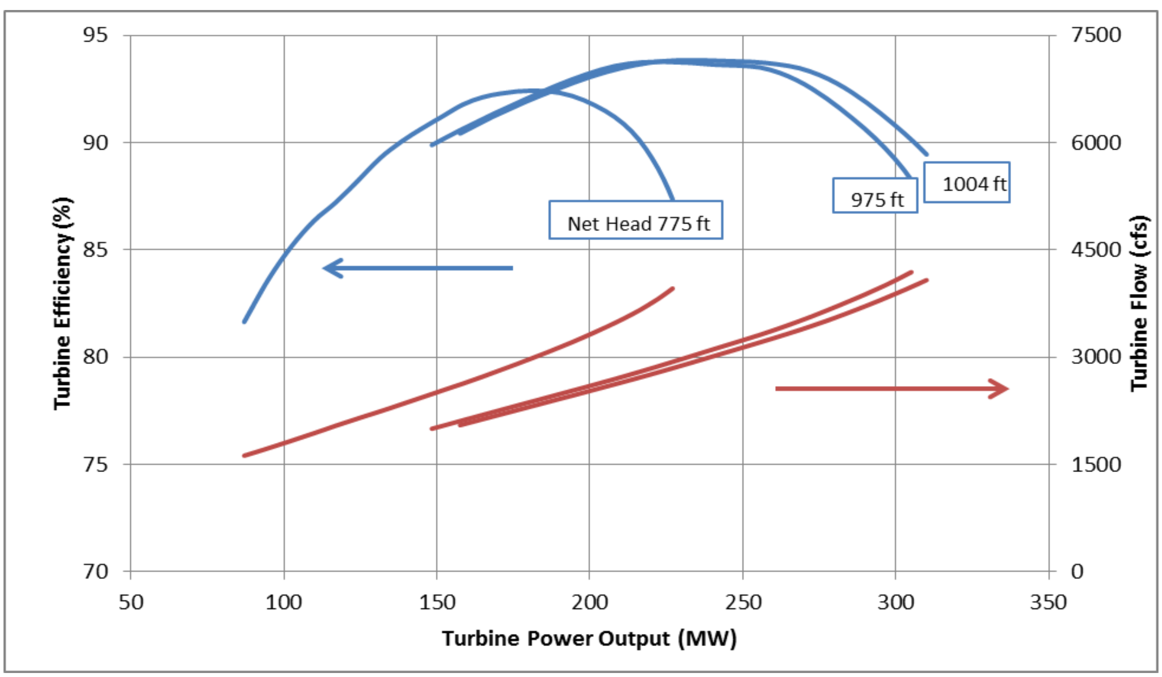


Figure 5-26. Seminoe 5C - Typical Power Range in Pumping Mode

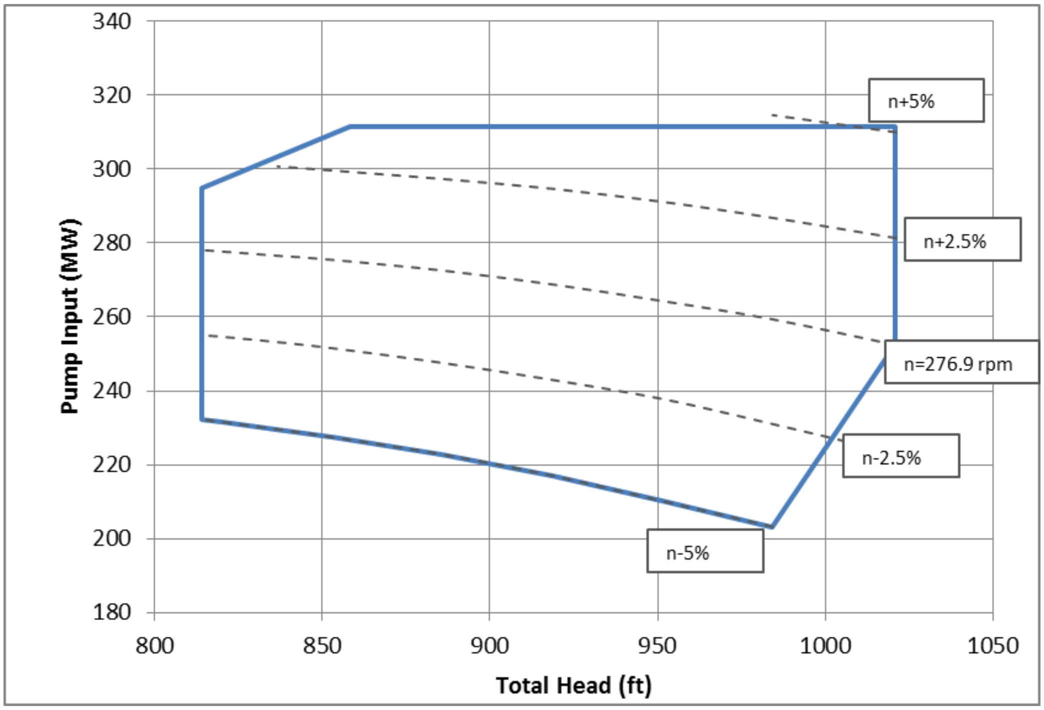
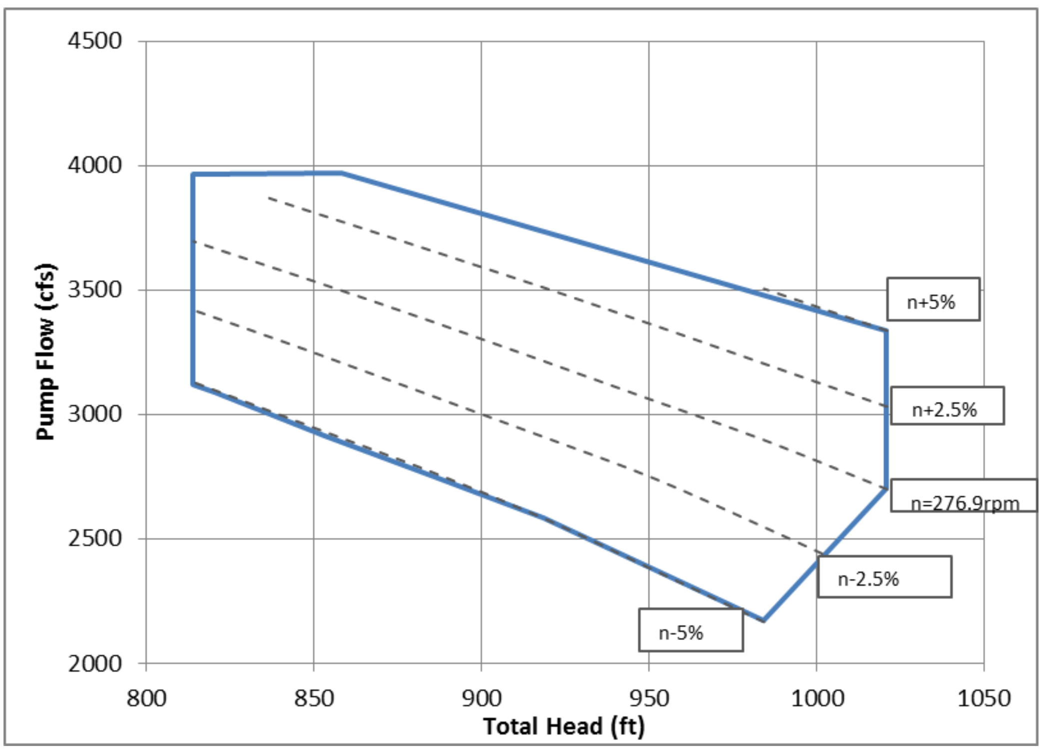


Figure 5-27. Seminoe 5C - Typical Range of Pumping Flow



5.6.2 Seminoe 5C Estimate of Unit Efficiencies

Tables 5-15 and 5-16 list pumping and generating efficiencies.

Table 5-15. Seminoe 5C Pumping Efficiencies

Component	Efficiency
Pump	92.5%
Motor	98.5%
Transformer	99.0%
Total pumping efficiency	90.2%

Table 5-16. Seminoe 5C Generating Efficiencies

Flow (cfs)	Turbine	Generator	Transformer	Total Generating Efficiency
1,000	82.0%	98.5%	99.0%	80.0%
1,500	86.5%	98.5%	99.0%	84.4%
2,000	89.9%	98.5%	99.0%	87.7%
2,500	92.8%	98.5%	99.0%	90.5%
3,000	93.7%	98.5%	99.0%	91.4%
3,700	91.8%	98.5%	99.0%	89.5%

5.6.3 Seminoe 5C Operational Capabilities

5.6.3.1 Incremental and Decremental Reserves

Utilizing advanced variable-speed technology, Seminoe Option 5C can provide between 293 MW and 515 MW of incremental reserves in generation mode (Table 5-18). The technology gives the plant the capability of bringing each unit from standstill to full load generation in less than three minutes. Each unit can generate between a minimum of 57 to 114 MW to a maximum of 286 MW (depending on the starting head differential), allowing it to provide between 89 MW and 229 MW of incremental reserves individually (Table 5-17). As the second unit is brought online, 286 MW of capacity and between 89 MW to 229 MW of incremental reserve capability can be added. By bringing units online and offline, and utilizing the output flexibility of each unit, the plant can provide between 293 to 515 MW of incremental reserves along a continuum. This process is described as follows, and illustrated in Figure 5-28.

Table 5-17. Seminoe 5C - Summary of Preliminary Unit Market Products

	Generate Mode					Pump Mode				
	Min MW	**Max MW**	**Incremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**
@ Min. Head	114	204	89	Full range of Unit Operations in < 3 Min	Full range of Unit Operations in < 6 Min	223	295	72	Full range of Unit Operations in < 4 Min	Full range of Unit Operations in < 8 Min
@ Max Head	57	286	229			252	311	59		

Table 5-18. Seminoe 5C - Summary of Preliminary Total Station Market Products

	Generate Mode			Pump Mode		
	Min MW	**Max MW**	**Incremental Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**
@ Min. Head	114	407	293	223	590	367
@ Max Head	57	572	515	252	622	370

Figure 5-28. Seminoe 5C Range of Generating Power Output

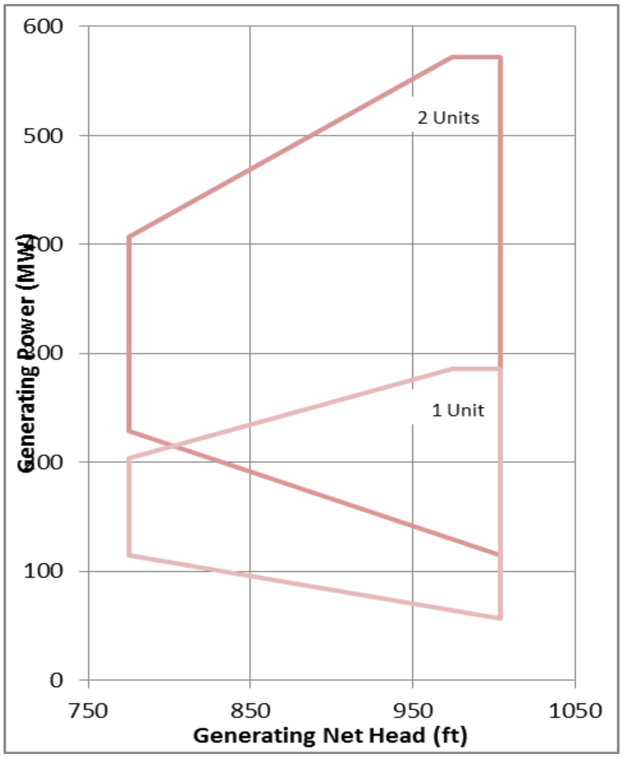
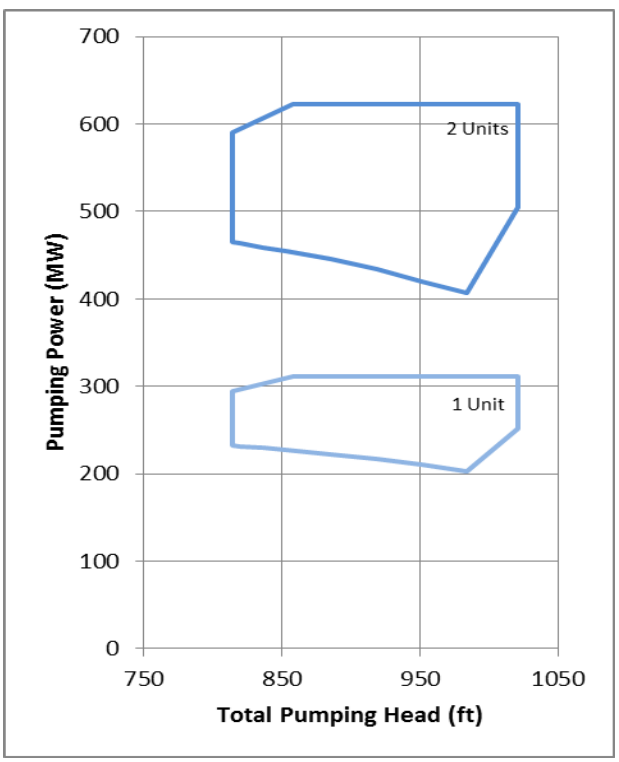


Figure 5-29. Seminoe 5C Range of Pumping Power Input



- **One-Unit Generation -** As the first unit is brought online, it has the ability to generate between 57 MW and 286 MW. As such, 229 MW (i.e., the difference between the minimum and maximum load generation) of incremental reserves can be provided. The actual generation output is dependent on the starting head differential of the upper and lower reservoirs.
- **Two-Unit Generation -** When a second unit is brought online, both units must generate at least 57 MW, giving the two units a total minimum output of 114 MW. In two-unit generation, the plant can generate between 114 MW and 572 MW.

In pumping mode, it is expected that each unit will be capable of starting at a minimum input power of 203 MW to 252 MW (depending on the head; see Figure 5-26) at low speed and rapidly ramping to 311 MW at high speed as necessary to support grid operations. From synchronous condense operation, each pump can reach full load in less than four minutes. From a cold start, each unit can reach full load operation in less than eight minutes. Similar to the continuum of incremental reserves achievable in generation mode, the plant is able to provide a significant range of decremental reserves in pumping mode by coupling each unit's 203 MW to 311 MW input range with the ability to operate more or less units (Figure 5-29).

It is possible to pump using 203 MW to 311 MW, and 406 MW to 622 MW of power and because units can reach full load in a relatively short period of time, this power input range can be used to provide decremental reserves.

5.6.3.2 Spinning and Non-Spinning Reserves

Refer to Section 5.3.3.2.

5.6.3.3 Frequency Regulation

Refer to Section 5.3.3.3.

5.6.3.4 Generating and Pumping Flexibility

As currently configured, with only one power tunnel, the two units must be moving water in the same direction. In other words, if one unit is in generate mode, the remaining unit can provide additional generation capability, or be in synchronous condense mode (either generating or pumping mode). The project, as currently conceived, does not have the capability to allow simultaneous generating and pumping, as currently configured.

5.6.3.5 Rapid Response

Refer to Section 5.3.3.5.

5.7 Trinity 5G2A Unit Operating Characteristics

5.7.1 Trinity 5G2A Operating Range

The operating range of a variable-speed pump-turbine requires to be optimized, using constrains of the installation and the desired flexibility of operation. Figures 5-30 and 5-31 show the operating range of the solution outlined in Table 5-1, using speed variation of ±5%. Figure 5-32 gives estimates of the generating performance. Analogous fields of pumping operation are shown in Figures 5-33 and 5-34.

Figure 5-30. Trinity 5G2A - Typical Range of Power in Generating Mode

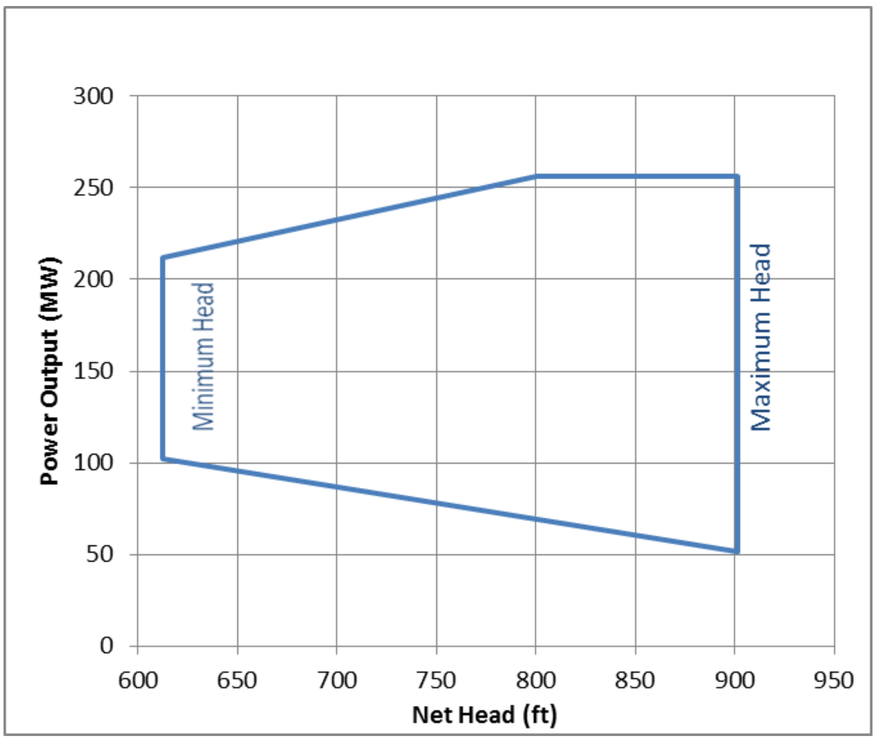


Figure 5-31. Trinity 5G2A - Typical Range of Flow in Generating Mode

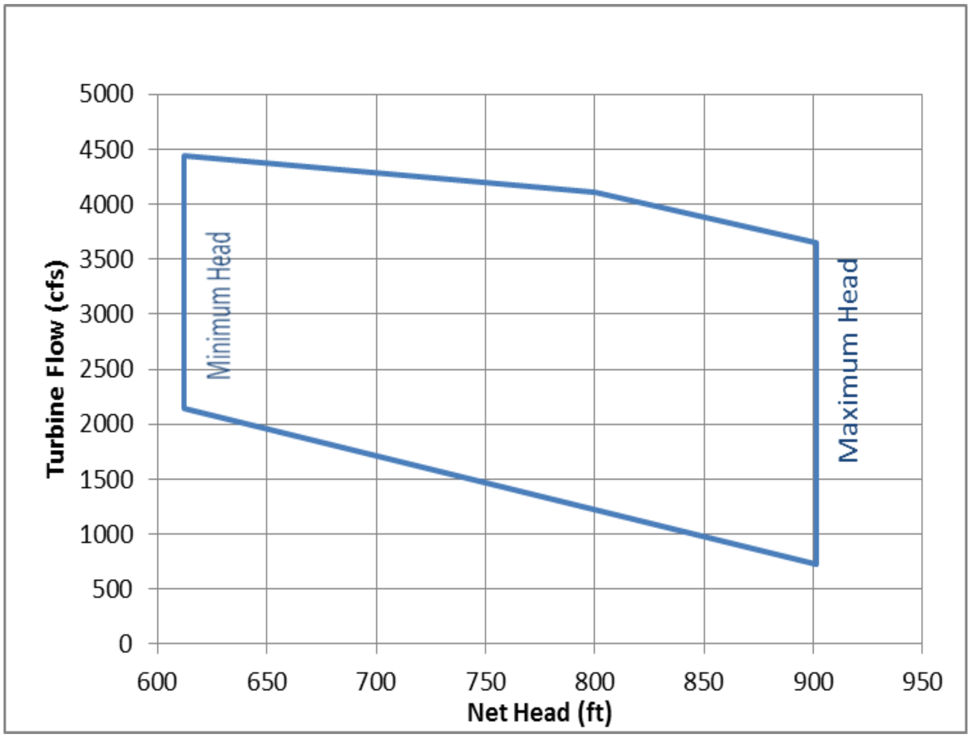


Figure 5-32. Trinity 5G2A - Estimated Generating Performance Curves

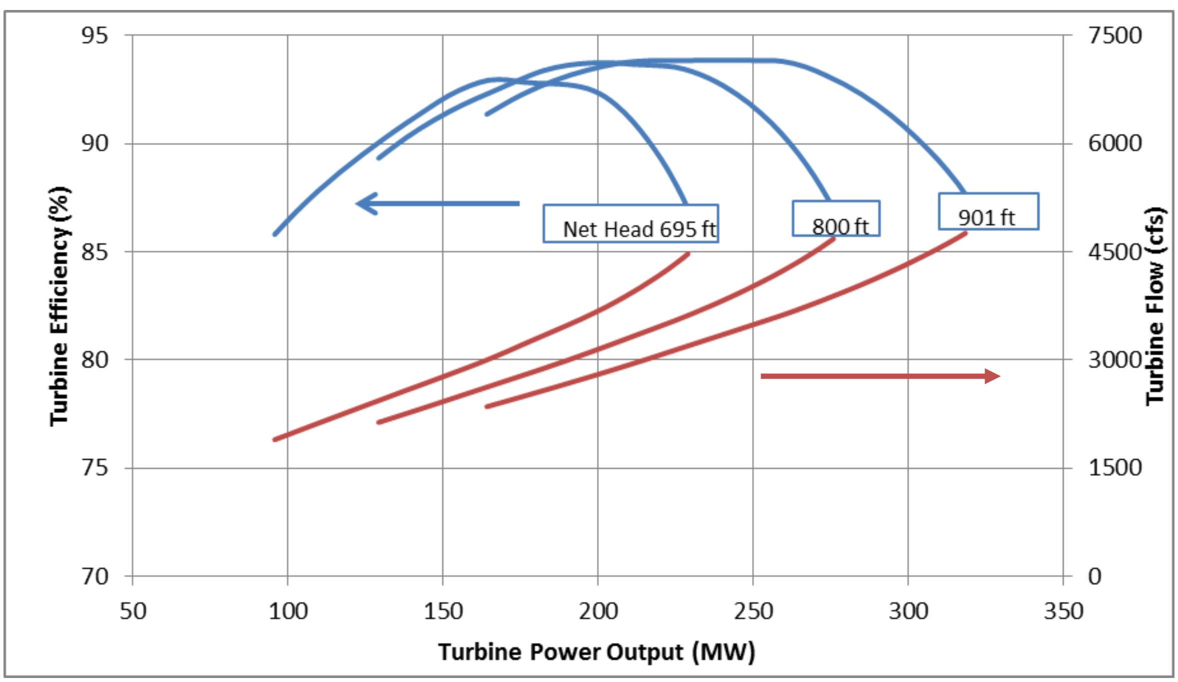


Figure 5-33. Trinity 5G2A - Typical Power Range in Pumping Mode

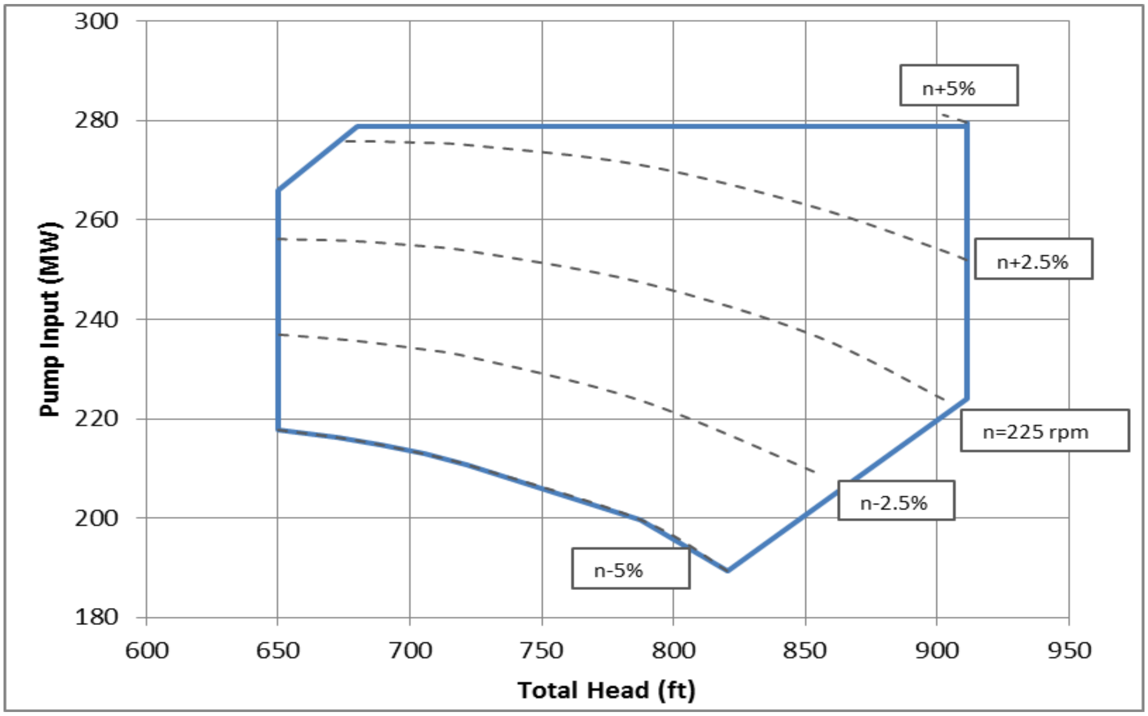
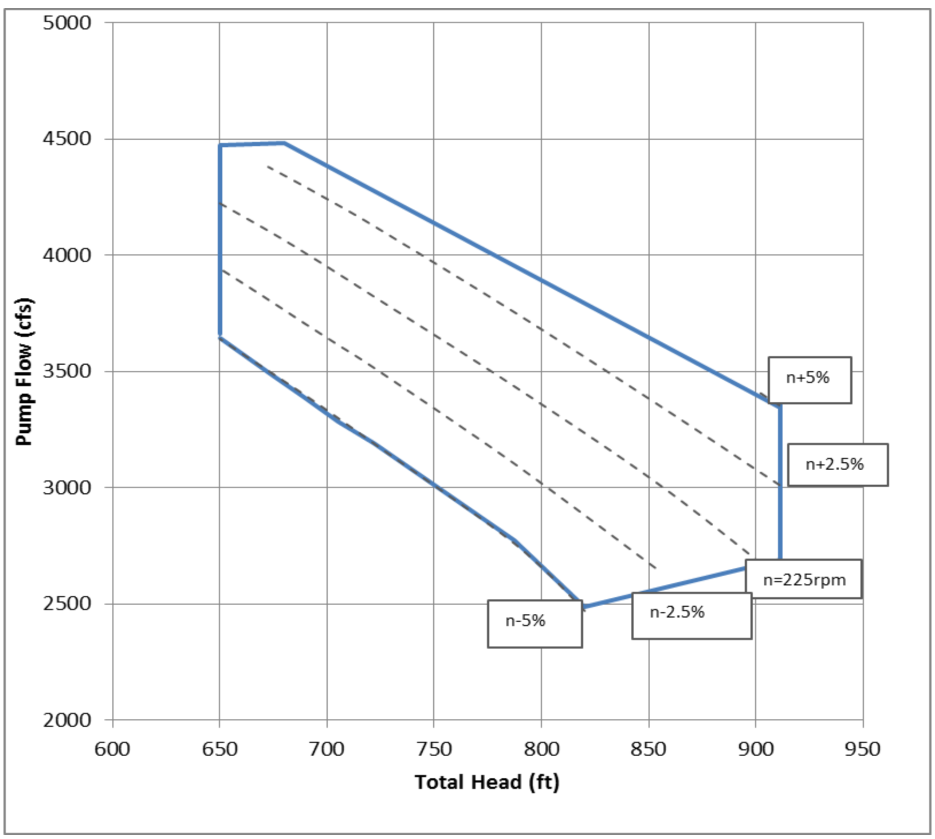


Figure 5-34. Trinity 5G2A - Typical Range of Pumping Flow



5.7.2 Trinity 5G2A Estimate of Unit Efficiencies

Tables 5-19 and 5-20 list pumping and generating efficiencies.

Table 5-19. Trinity 5G2A Pumping Efficiencies

Component	Efficiency
Pump	92.1%
Motor	98.5%
Transformer	99.0%
Total pumping efficiency	89.8%

Table 5-20. Trinity 5G2A Generating Efficiencies

Flow (cfs)	Turbine	Generator	Transformer	Total Generating Efficiency
1,500	85.0%	98.5%	99.0%	82.9%
2,000	89.0%	98.5%	99.0%	86.8%
2,500	91.7%	98.5%	99.0%	89.5%
3,000	93.6%	98.5%	99.0%	91.3%
3,500	93.6%	98.5%	99.0%	91.3%
4,000	91.9%	98.5%	99.0%	89.6%
4,500	88.5%	98.5%	99.0%	86.3%
4,700	86.8%	98.5%	99.0%	84.7%

5.7.3 Trinity 5G2A Operational Capabilities

5.7.3.1 Incremental and Decremental Reserves

Utilizing advanced variable-speed technology, Trinity Option 5G2A can provide between 744 MW and 973 MW of incremental reserves in generation mode (Table 5-22). The technology gives the plant the capability of bringing each unit from standstill to full load generation in less than three minutes. Each unit can generate between a minimum of 51 to 102 MW to a maximum of 256 MW (depending on the starting head differential), allowing it to provide between 109 MW to 205 MW of incremental reserves individually (see Table 5-21). As each additional unit is brought online, 256 MW of capacity and between 109 MW to 205 MW of incremental reserve capability can be added. By bringing units online and offline, and utilizing the output flexibility of each unit, the plant can provide between 744 to 973 MW of incremental reserves along a continuum. This process is described as follows, and illustrated in Figure 5-35 below.

Table 5-21. Trinity 5G2A - Summary of Preliminary Unit Market Products

	Generate Mode					Pump Mode				
	Min MW	**Max MW**	**Incremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**	**Spinning Reserves**	**Non Spinning Reserves**
@ Min. Head	102	212	109	Full range of Unit Operations in < 3 Min	Full range of Unit Operations in < 6 Min	218	266	48	Full range of Unit Operations in < 4 Min	Full range of Unit Operations in < 8 Min
@ Max Head	51	256	205			224	280	56		

Table 5-22. Trinity 5G2A - Summary of Preliminary Total Station Market Products

	Generate Mode			Pump Mode		
	Min MW	**Max MW**	**Incremental Reserves**	**Min MW**	**Max MW**	**Decremental Reserves**
@ Min. Head	102	847	744	218	1,064	846
@ Max Head	51	1,024	973	224	1,119	895

Figure 5-35. Trinity 5G2A Range of Generating Power Output

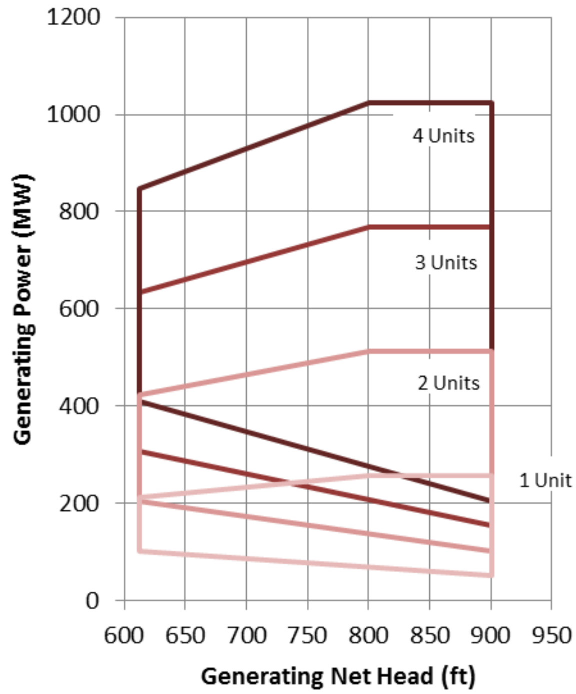
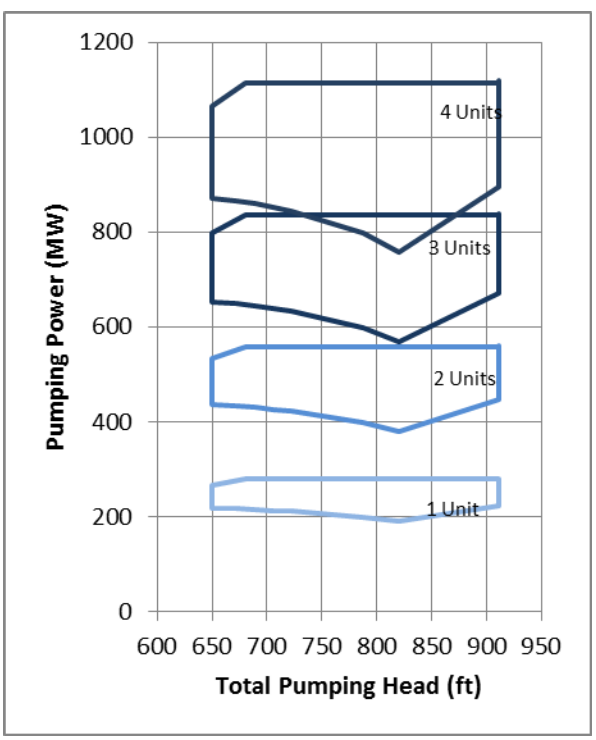


Figure 5-36. Trinity 5G2A Range of Pumping Power Input



- **One-Unit Generation -** As the first unit is brought online, it has the ability to generate between 51 MW and 256 MW. As such, 205 MW (i.e., the difference between the minimum and maximum load generation) of incremental reserves can be provided. The actual generation output is dependent on the starting head differential of the upper and lower reservoirs.
- **Two-Unit Generation -** When a second unit is brought online, both units must generate at least 51 MW, giving the two units a total minimum output of 102 MW. In two-unit generation, the plant can generate between 102 MW and 512 MW.
- **Three-Unit Generation –** When a third unit is brought online, all units must generate at least 51 MW but no more than 256 MW, giving the three units a minimum output of 153 MW and maximum output of 768 MW.
- **Four-Unit Generation –** When the final unit is brought online, the total minimum output of the plant is 204 MW, and the total maximum output is 1,024 MW.

In pumping mode, it is expected that each unit will be capable of starting at a minimum input power of between 189 MW and 218 MW (depending on the head; see Figure 5-33) at low speed and rapidly ramping to 279 MW at high speed as necessary to support grid operations. From synchronous condense operation, each pump can reach full load in less than four minutes. From a cold start, each unit can reach full load operation in less than 8 minutes. Similar to the continuum of incremental reserves achievable in generation mode, the plant is able to provide a significant range of decremental reserves in pumping mode by coupling each unit’s 189 MW to 279 MW input range with the ability to operate more or less units (Figure 5-36).

It is possible to pump using 189 MW to 279 MW, and 756 MW to 1,116 MW of power and because units can reach full load in a relatively short period of time, this power input range can be used to provide decremental reserves.

5.7.3.2 Spinning and Non-Spinning Reserves

Refer to Section 5.3.3.2.

5.7.3.3 Frequency Regulation

Refer to Section 5.3.3.3.

5.7.3.4 Generating and Pumping Flexibility

As currently configured, with two power tunnels and two units assigned to each tunnel, two units must be moving water in the same direction. In other words, for a given power tunnel, if one unit is in generate mode, the remaining unit can provide additional generation capability, or be in synchronous condense mode (either generating or pumping mode). The project, as currently conceived, has the capability to allow simultaneous generating and pumping.

5.7.3.5 Rapid Response

Refer to Section 5.3.3.5.

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Chapter 6
Conceptual Layout and Cost Evaluation Studies

6.1 General Procedures and Assumptions

The primary objectives of this task were to utilize the project information generated to date and develop conceptual layouts for each of the project sites, including sizing, performing quantity take-offs, and generating Class 4 cost opinions for the following major project elements:

- Reservoirs and dams
- Water conveyance systems
- Powerstation and associated equipment
- Switchyard and transmission facilities
- Project access
- Project lands

The primary resources utilized for this task included:

- EPRI Document No. GS-6669 (1990), indexed to 2012 dollars using an escalation an average escalation factor of 3.0, and
- HDR's internal data base of cost elements for similar projects.

6.2 General Layout Considerations

For each proposed pumped storage project, the following various alignment and configurations were considered in an effort to:

- Minimize the length of tunnels and associated hydraulic losses;
- Obtain adequate overburden above the high pressure headrace tunnel;
- Minimize afterbay excavation within the waters of the lower reservoir;
- Minimize operating impacts to the lower reservoir;
- Minimize the potential for surge facilities;
- Obtain sufficient submergence at both intakes;
- Facilitate constructability;
- Minimize adverse visual aesthetics;
- Minimize construction cost; and
- Maximize operational benefit.

Volume 2 includes the preliminary drawings to support the information provided in this section.

6.3 Power Complex Development

Trade-off and configuration studies were performed assuming an underground powerhouse based on adequate unit submergence and headrace tunnel cover.

The selected project configuration for each underground power complex is shown in Volume 2, and consists of a vertical type bellmouth intake structure, vertical shaft, horizontal power tunnel, manifold, individual unit penstocks, underground powerhouse, draft tubes, tailrace tunnels, discharge structure, main powerhouse access tunnel and high voltage bus/HVAC tunnel.

6.3.1 Upper Reservoir Intake

An intake would be required where the vertical power tunnel meets the upper reservoir. For the purpose of this study, a vertical intake is shown, applicable by comparison to the existing Bear Swamp, Rocky Mountain, and Bad Creek pumped storage facilities. To suppress vortices, either a hood or other type of vortex suppression device is typically installed.

In the event the headrace tunnel would need to be dewatered for inspection and/or maintenance, and to ensure an adequate volume of water to refill the power tunnel (to prime the pumps) post-dewatering, a water-retaining structure is generally used to isolate the intake area from the waters remaining in the upper reservoir during a drawdown condition. Such a structure would permit the reservoir to be lowered, allowing several days for inspection and sufficient water to refill the power tunnel above equalization from the lower reservoir.

Since the entire upper reservoir is off-stream and to be cleared, no trash racks are anticipated for the upper reservoir intake structure and hence no associated head loss across the racks.

6.3.2 Powerhouse Location, Arrangement, and Sizing

The conceptual layout of the underground powerhouse is largely dictated by unit centerline elevation, geological features, construction limits associated with tunneling, and hydraulic design and configuration of the water conveyance tunnels. For the purpose of this study, the project team has assumed the following:

- The underground powerhouse measurements were selected based on the physical unit dimensions and required submergence shown in Chapter 2.

- The powerhouse was located approximately mid-way between the upper and lower reservoirs in such a manner to satisfy minimum rock cover for tunnels. Both the powerhouse location and orientation will need to be adjusted and confirmed via additional geotechnical/geological and unit/technical studies.
- At this time, the tunnels have been sized in an effort to avoid the need for surge chambers. Additional studies would be required to confirm this assumption.
- A maximum slope of 10% is assumed sufficient to accommodate tunnel construction.
- A transformer gallery is located in a separate cavern adjacent to the powerhouse cavern to minimize long-term energy losses associated with an externally located transformer yard. The same cavern also houses four draft tube gates.
- For the purpose of isolating a single unit post-tunnel filling, isolation valves and draft tube gates are located upstream and downstream of each unit, respectively.
- Permanent access to the powerhouse is assumed to be provided by both a 25-foot-high access tunnel and a similar sized tunnel to accommodate high-voltage cable and HVAC equipment.
- A number of construction access tunnels are shown, which will be isolated from the water conveyance tunnels via concrete plugs.
- A powerhouse bypass tunnel has been included for the primary purpose of installing subsurface drains to intercept seepage/groundwater and relieve hydrostatic pressure which could be imposed against the upstream powerhouse wall.

6.3.3 Minimum Rock Cover Criteria for Unlined High Pressure Headrace Tunnels

According to EPRI 1990, the criteria for minimum rock cover for tunnels is estimated by the following relationship:

$$C_{RM} = (h_s * \gamma_w * F) / (\gamma_R * COS\beta)$$

Where:

CRM = Minimum Rock Cover (ft)
Hs = Static Head (ft)
γ_w = Unit Weight of Water
$\gamma_{P =}$ Unit Weight of Rock
β = Slope Angles (Varies along slope)
F = Safety Factor (1.5)

6.4 Reservoirs and Dams

6.4.1 Reservoirs

Reservoirs were sized using methods discussed in Chapter 2 of this report. General information related to these studies, including area-volume curves, dam profiles, and area-volume data. Reservoir drawdown limits were assumed limited to approximately 30 percent of the static head, which is common for pump-turbine operational restrictions and acceptable for the dam structures identified below.

6.4.2 Upper Reservoir Dams

6.4.2.1 Description

For the purpose of this study, all dams were assumed to be rockfill concrete face type. Material take-off estimates were performed for each dam structure assuming a crest elevation 10 feet higher than the maximum reservoir elevation as well as upstream and downstream slopes of 1.5H:1.0V. Dam heights were increased by an additional 10 feet to account for foundation and abutment stripping, and other factors. More detailed studies are required to confirm material availability, technical acceptable embankment types and methods of construction. Listed below are the physical features that typically govern the selected dam type:

- Topography
- Geology and Foundation Conditions
- Material Availability
- Spillway Size and Location
- Freeboard
- Earthquake Consideration
- Functional Requirements
- Appearance

6.4.2.2 Basis of Direct Costs

The initial approach to estimating costs was stochastic, utilizing cost curves presented in Figure 6-10 in EPRI Document No. GS-6669 (1990). These costs were presented in 1988 dollars and then escalated to 2012 dollars using an index factor of 3.0. Table 6-1 lists the results of this study for each site.

Table 6-1. Estimated Earthwork Volumes and Construction Costs

Site		Approx. Max Dam Height	Estimated Volume (CY)	1988 Est. Unit Costs ($/CY)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	298	5,987,000	7.50	3.0	134,707,500
Seminoe	5A2	407	7,000,000	7.50	3.0	157,500,000
	5A3	317	7,380,000	7.50	3.0	166,050,000
	5C	336	7,231,000	7.50	3.0	162,697,500
Trinity	5G2A	139	2,912,000	7.50	3.0	65,520,000

A unit-based cost approach for a similar concrete-faced, rockfill structure yielded a total construction cost opinion of approximately $26 per cubic yard. For the purpose of this report, it is assumed that a concrete face rockfill embankment and construction cost would be $26 per cubic yard.

6.4.3 Stream Diversion

A stream diversion system would be installed to divert flows during construction of the upper reservoir main dam. For the purpose of this estimate, $9,000,000 has been allocated for the installation of a stream diversion system.

6.4.4 Upper Reservoir Liner

Based on geologic studies, it is prudent to include the cost for an upper reservoir liner at Yellowtail. This is due to the karstic limestone (refer to Chapter 3) that underlies the reservoir site. Sandstone also overlies the limestone in most of the reservoir areas; however, the porosity and/or fracturing of the sandstone is not known. If highly fractured, it would provide a direct path to the karstic limestone, which is likely highly permeable based on the large number of caves, caverns, and openings that have developed in it.

At this time, the Seminoe and Trinity sites are not likely to require reservoir liners based on preliminary review of the sites' geologic conditions. Additional investigations would be required to confirm reservoir liners are not required at these sites.

Common reservoir liners utilized for reservoir applications include the following:

- High Density Polyethylene (HDPE)
- Linear Low-Density Polyethylene (LLDPE)
- Flexible Polypropylene (fPP)
- Polyvinyl Chloride (PVC)
- Ethylene Propylene Diene Monomer (EPDM)
- Geosynthetic Clay Liner (GCL)

Table 6-2 lists of key advantages and disadvantages of each liner type.

Table 6-2. Key Advantages and Disadvantages for Reservoir Liner Types

Liner Type	Key Advantages	Key Disadvantages
High Density Polyethylene (HDPE)	• Excellent UV resistance • Examples of large reservoir projects • Data on service life available • High tear strength • Low cost • Large thicknesses (up to 3 mm)	• High potential for wrinkles • Low multiaxial elongation (least potential to conform to localized settlement) • Susceptible to long-term stress crack under localized strain
Liner Low-Density Polyethylene (LLDPE)	• Excellent flexibility • Excellent puncture resistance • Good resistance to stress cracking • Low cost • Large thicknesses (up to 3 mm) available	• No focused research on service life • No examples of large reservoir projects
Flexible Polypropylene (fPP)	• Excellent multiaxial elongation • Excellent flexibility for detailed work • Excellent puncture resistance • Not susceptible to stress cracking	• No focused research on service life • No examples of large reservoir projects • Only available up to 1.5 mm • Higher cost
Polyvinyl Chloride (PVC)	• Excellent flexibility for detailed work • Excellent multiaxial elongation • Higher specific gravity (1.2 min.) • Excellent puncture resistance • Good resistance to stress cracking	• No focused research on service life • Poor UV resistance • Higher cost • Low tear strength • Only available up to 1.5 mm thickness
Ethylene Propropylene Diene Monomer (EPDM)	• Excellent UV resistance • Good flexibility for detailed work • Low susceptibility to wrinkle formation • Higher specific gravity (1.15 min.) • Examples of large reservoir projects • Good puncture resistance • Not susceptible to stress cracking	• No focused research on service life • Low tear strength • Taped seams harder to construct • Only available up 1.5 mm thickness • High cost
Geosynthetic Clay Liner (GCL)	• Not susceptible to wind uplift during construction • Examples of large reservoir projects • Not susceptible to stress cracking • Low cost • Not susceptible to wrinkle formation	• Has to be covered • Highly susceptible to water damage during construction • Potential for internal erosion under high hydraulic gradient • Low strain at break • Difficult to seal around appurtenances

For the purpose of this report, the project team has assumed an HDPE liner will be installed in the Yellowtail upper reservoir having an installed cost of

$4,000,000 using $5 per square yard (installed) and an upper reservoir area of 166 acres (803,440 square yards).

6.4.5 Spillway

There is very little drainage area associated with the impoundment of the upper reservoir, and therefore no major spillway is assumed necessary for the purpose of passing a probable maximum flood. To protect the impoundments against the possibility of over-pumping, A cost of $5,000,000 is included for the construction of the spillway for each site.

6.5 Powerstation Structure (Civil Works)

The initial approach taken to estimate costs was stochastic, utilizing cost curves presented in Figure 6-9 in EPRI Document No. GS-6669 (1990). These costs were presented in 1988 dollars and escalated to 2012 dollars using an index factor of 3.0. The project team then performed a unit-based cost approach for a similar 1,000 MW, four-unit underground powerhouse structure yielding a total construction cost opinion of approximately $200 per kW. The costs presented within the EPRI report (using an escalation factor of 3.0) appeared to be approximately 25 percent less than similar unit costs opinion. Therefore, for the purpose of this study, an escalation factor of 4.0 was used as opposed to 3.0. Table 6-3 lists the results of this study for each site.

Table 6-3. Powerstation Construction Costs

Site		Assumed Static Head (ft)	Installed Capacity (MW)	No. Units	MW per Unit	1988 Unit Costs ($/kW)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	1,562	1,660	4	415	30	4.0	199,211,563
Seminoe	5A2	872	859	4	215	48	4.0	164,947,927
	5A3	1,022	1,104	4	276	41	4.0	180,991,070
	5C	909	572	2	286	55	4.0	125,745,408
Trinity	5G2A	775	1,024	4	256	55	4.0	225,389,188

6.6 Water Conveyance, Equipment, Transmission, and Other Civil Works

6.6.1 Profile Assumptions

The water conveyance profile for each site was assumed to consist of a vertical intake/shaft, horizontal power tunnel, underground power station, draft tube tunnels, and tailrace tunnels. All tunnels were assumed to be fully lined with concrete. Penstocks were assumed to be steel-lined upstream of the powerhouse for a distance of approximately 25 percent of maximum head.

6.6.2 Water Conductor Sizing Assumptions

6.6.2.1 Generating Discharge

The generating discharge is calculated as follows:

Q = 11,800 C/He

Where: Q = Design Generating Discharge (cfs)
C = Rated Generating Capacity (MW)
H = Gross Head (ft)
e = Overall Generating Efficiency (assumed 0.86)

6.6.2.2 Flow Velocity

The criteria for estimating the maximum water velocity within the headrace tunnel was estimated as follows:

- If L/H < 6, then no surge chamber is assumed.
- If L/H is > 6, then compute the maximum water velocity using the following relationship:

V = 120 H/L

- Re-estimate water conductor dimensions using the equation in Section 6.6.2.3 and make provisions for surge protection.
- The maximum velocity within the headrace tunnel should not be greater than 23 ft/sec.

The maximum velocity with the penstock and draft tubes was estimated using the following criteria (Table 6-4):

Table 6-4. Flow Velocity Criteria

Maximum Head (ft)	Penstock Tunnel Velocity (fps)	Draft Tube Tunnel Velocity (fps)
200	17	6
300	18	8
500	20	10
1,000	25	13
1,500	28	15
2,200	32	17

6.6.2.3 Tunnel Diameter

The water conductor diameter was estimated using the following relationship:

$$D = (1.273\ Q/V)^{0.5}$$

Where: D = Water Conductor Diameter (ft)
Q = Generating Discharge (cfs)
V = Generating Velocity (ft/sec)

For tunnel diameters greater than approximately 35 feet, an additional tunnel is recommended. The resulting water conveyance characteristics for each site are shown in Table 6-5. Cost elements are provided in the following subsections.

Table 6-5. Water Conveyance Characteristics

Site		General Site Preliminary Characteristics				Water Conveyance System - Preliminary Characteristics							
		Assumed Installed Capacity (MW) [1]	Approx. Static Head (H) (ft)	Est. Water Conductor Length (L) (ft)	Generating Discharge (cfs)	Tunnel Diameter (ft)	No. of Headrace Tunnels	Penstock Diameter (ft)	No. of Penstocks	Draft Tube Diameter (ft)	No. of Draft Tubes	Tailrace Tunnel Diameter (ft)	No. of Tailrace Tunnels
Yellowtail	5A	1,660	1,562	7,950	14,586	31	1	13	4	18	4	25	2
Seminoe	5A2	859	872	8,700	13,525	38	1	15	4	21	4	24	2
	5A3	1,104	1,022	6,625	14,823	37	1	14	4	19	4	25	2
	5C	572	909	7,160	8,627	31	1	17	2	23	2	27	1
Trinity	5G2A	1,024	775	8,875	18,137	30	2	17	4	24	4	28	2

[1] Based on a 10-hour run time.

6.6.3 Upper Reservoir Intake

The upper reservoir intake for each site was assumed to be a submerged reinforced concrete vertical type bellmouth hooded structure, ungated with no trashracks, and located within a depression to provide sufficient submergence for generation with the reservoir nearly empty. However, the most cost-effective means for isolating the units has yet to be determined. Table 6-6 lists the estimated costs for intakes. These costs were derived from Figure 6-12 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0, reflecting a recent unit based cost opinion performed for a similar type of development.

Table 6-6. Intake Characteristics and Estimated Costs

Site		No. of Tunnels	Tunnel Diameter (ft)	1988 Est. Unit Costs ($)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	1	31	2,200,000	3.0	6,600,000
Seminoe	5A2	1	38	4,000,000	3.0	12,000,000
	5A3	1	37	3,900,000	3.0	11,700,000
	5C	1	31	2,200,000	3.0	6,600,000
Trinity	5G2A	2	30	2,200,000	3.0	13,200,000

6.6.4 Vertical Shaft

For each site, a concrete-lined vertical shaft was assumed to extend from the intake structure to the horizontal power tunnel. The shaft height for each site was assumed to be equal to the static head. Table 6-7 lists the costs for the vertical shaft structures for each of the sites. The costs were derived from Figure 6-14 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 6-7. Vertical Shaft Structure Characteristics and Estimated Costs

Site		No. of Tunnels	Height of Shaft (ft)	Total Length of Shaft (ft)	Tunnel Diameter (ft)	1988 Est. Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	1	1,500	1,500	31	5,800	3.0	26,100,000
Seminoe	5A2	1	600	600	38	7,000	3.0	12,600,000
	5A3	1	950	950	37	7,000	3.0	19,950,000
	5C	1	710	710	31	5,800	3.0	12,354,000
Trinity	5G2A	2	775	1,550	30	5,700	3.0	26,505,000

6.6.5 Horizontal Power Tunnel

Concrete-lined power tunnels are assumed to extend from the vertical shaft to the penstock manifold. Table 6-8 lists costs for the power tunnels for each site. The unit costs were derived from Figure 6-13 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 6-8. Power Tunnel Characteristics and Estimated Costs

Site		No. of Tunnels	Length of Each Tunnel (ft)	Total Tunnel Length (ft)	Tunnel Diameter (ft)	1988 Est. Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	1	3,500	3,500	31	6,200	3.0	65,100,000
Seminoe	5A2	1	4,000	4,000	38	8,000	3.0	96,000,000
	5A3	1	2,500	2,500	37	8,000	3.0	60,000,000
	5C	1	3,100	3,100	31	5,000	3.0	46,500,000
Trinity	5G2A	2	4,000	8,000	30	6,000	3.0	144,000,000

6.6.6 Penstock

Steel-lined penstock tunnels are assumed to extent upstream of the powerhouse for a distance to equal 25 percent of the maximum head. The power tunnel-to-penstock transitions are assumed to occur via a distribution manifold into individual unit penstocks. Table 6-9 lists the penstock characteristics and costs for each site. The unit costs were derived from Figure 6-15 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 6-9. Penstock Characteristics and Estimated Costs

Site		No. of Penstocks	Length of Each Penstock (ft)	Total Length of Penstock	Dia. (ft)	Head (ft)	1988 Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	4	450	1,800	13	1,562	5,000	3.0	27,000,000
Seminoe	5A2	4	300	1,200	15	872	4,200	3.0	15,120,000
	5A3	4	375	1,500	14	1,022	4,000	3.0	18,000,000
	5C	2	300	600	17	909	5,400	3.0	9,720,000
Trinity	5G2A	4	325	1,300	17	775	5,200	3.0	20,280,000

6.6.7 Draft Tube Tunnels and Gates

Table 6-10 presents the draft tube detail for each site. The unit costs were derived from Figure 6-15 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 6-10. Draft Tube Characteristics and Estimated Costs

Site		No. of Draft Tubes	Length of Each Draft Tube (ft)	Total Length of Draft Tube (ft)	Dia. (ft)	Head (ft)	1988 Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	4	250	1,000	18	1,562	8,300	3.0	24,900,000
Seminoe	5A2	4	250	1,000	21	872	7,700	3.0	23,100,000
	5A3	4	250	1,000	19	1,022	7,000	3.0	21,000,000
	5C	2	250	500	23	909	9,800	3.0	14,700,000
Trinity	5G2A	4	250	1,000	24	775	9,600	3.0	28,800,000

6.6.8 Draft Tube Gate/Transformer Gallery

The substation for each site would be located in an underground cavern located just downstream of the powerhouse within a common draft tube gate/transformer gallery. For the four-unit projects, this cavern was assumed to measure approximately 45 feet wide, 55 feet tall, and 500 feet long. According to recent quotes for similar structures, the cost of this installation would be approximately $26,000,000 for the four-unit projects (Yellowtail 5A, Seminoe 5A2 and 5A3, and Trinity 5G2A). For the two-unit project (Seminoe 5C), costs would be $13,000,000.

6.6.9 Tailrace Tunnels

A concrete-lined tailrace tunnel was assumed for every two draft tube tunnels, extending to the lower reservoir discharge structure. Table 6-11 lists the costs for the tailrace tunnels for each site. The unit costs were derived from Figure 6-13 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 6-11. Tailrace Tunnel Characteristics and Estimated Costs

Site		No. of Tailrace Tunnels	Length of Each Tailrace Tunnel (ft)	Total Length of Tailrace Tunnel (ft)	Dia. (ft)	1988 Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	2	2,150	4,300	25	4,000	3.0	51,600,000
Seminoe	5A2	2	3,500	7,000	24	3,500	3.0	73,500,000
	5A3	2	2,500	5,000	25	3,500	3.0	52,500,000
	5C	1	2,750	2,750	27	3,800	3.0	31,350,000
Trinity	5G2A	2	3,500	7,000	28	5,200	3.0	109,200,000

6.6.10 Lower Reservoir Discharge/Intake Structure and Channel

A discharge/intake structure and channel will need to be constructed for each site in the waters of the lower reservoir. Table 6-12 lists the costs for the lower reservoir discharge/intake for each site, which consists of a horizontal intake.

The unit costs were derived from Figure 6-12 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 6-12. Lower Reservoir Characteristics and Estimated Costs

Site		No. of Tunnels	Dia. (ft)	1988 Unit Costs ($)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	2	25	6,500,000	3.0	39,000,000
Seminoe	5A2	2	24	5,900,000	3.0	35,400,000
	5A3	2	25	6,500,000	3.0	39,000,000
	5C	1	27	7,500,000	3.0	22,500,000
Trinity	5G2A	2	28	8,200,000	3.0	49,200,000

6.6.11 Surge Chambers

In general, water conductors and associated appurtenances are designed to accommodate permissible head losses and tunnel velocities, possess sufficient ability to follow load changes, and offer protections to structural members from excess pressure in the event of sudden gate changes and/or load rejections. When the control, directed by the governor, causes undesirable pressure variations (generally 40 percent rise and 25 percent drop), a surge chamber is often used to dissipate transient pressures. A surge chamber is generally a tank, cavern, or shaft consisting of an atmospheric standpipe, attached to the headrace tunnel and/or penstock. This facility provides a reservoir and expansion chamber to accommodate water demand or water rejection following sudden gate movements to mitigate internal pressures and rapid accelerations or decelerations of the flow within the water conveyance system.

According to the procedures cited herein, no surge chamber is required for Yellowtail 5A. However, cost allocations equal to 30 percent of the water conductor costs have been made for surge chambers at the Seminoe and Trinity projects. Firm determination, sizing, and location(s) of the water conductors and associated surge protections are beyond the scope of this study.

6.6.12 Powerstation Equipment

Table 6-13 lists underground powerhouse equipment cost estimates complete with assumptions for each of the sites. The 1988 cost estimates provided in this table were obtained from Figures 6-17 through 6-18 of EPRI Document No. GS-6669 and include the items listed below. These costs were then indexed to 2012 dollars using an escalation factor of 4.0 as opposed to 3.0 based on recent quotes for similar variable-speed equipment.

- **Major Equipment:** Includes pump/turbines, governors, inlet valves, and generator/motors.

- **Accessory Electrical Equipment:** Includes main transformers, control and communications equipment, starting equipment, main leads, breakers, switches, and current limiting reactors.
- **Miscellaneous Mechanical Equipment:** Includes bridge crane, HVAC, cooling water, drainage, compressed air system, emergency diesel generator, and other smaller items.

Table 6-13. Power Equipment Costs

Site		Design Head (ft)	Installed Capacity (MW)	No. Units	MW per Unit	1988 Unit Costs ($/kW)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	1,562	1,660	4	415	105	4.0	697,240,470
Seminoe	5A2	872	859	4	215	135	4.0	463,916,043
	5A3	1,022	1,104	4	276	130	4.0	573,874,124
	5C	909	572	2	286	136	4.0	310,934,100
Trinity	5G2A	775	1,024	4	256	133	4.0	545,032,036

6.6.13 Power Complex Access Tunnels

Access to each underground power complex was assumed to be via a main access tunnel and a high-voltage/HVAC tunnel. Each tunnel was assumed to be a 25-foot-tall, horseshoe-type installed on a maximum slope of 10 percent. Table 6-14 lists the costs for the power complex access tunnels. The unit costs were derived from Figure 6-19 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 6-14. Access Tunnel Characteristics and Estimated Costs

Site		Access Tunnel Length (ft)	1988 Est. Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	3,000	2,400	3.0	21,600,000
Seminoe	5A2	2,600	2,400	3.0	18,720,000
	5A3	2,600	2,400	3.0	18,720,000
	5C	2,600	2,400	3.0	18,720,000
Trinity	5G2A	2,700	2,400	3.0	19,440,000

6.6.14 Underground Excavation Haul Tunnels

For each project, approximately 2,000 feet of tunnels would be required for the purpose of removing tunnel spoils during construction of the underground power complex and water conveyance tunnels. The costs of these tunnels have been estimated to cost in the order of $5,000 per linear foot, for a total cost opinion of $12,000,000.

6.6.15 Switchyard

To estimate the switchyard cost, the project team assumed a conventional outdoor air-insulated substation with voltages consistent with that listed above for the new transmission lines. The 1988 cost estimates provided in Table 6-15 were obtained from Figure 6-20 of EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars assuming an index factor of 3.0.

Table 6-15. Switchyard Characteristics and Estimated Costs

Site		Assumed Voltage (kV)	Installed Capacity (MW)	No. Units	1988 Unit Costs ($)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	500	1,660	4	14,000,000	3.0	42,000,000
Seminoe	5A2	345	859	4	8,000,000	3.0	24,000,000
	5A3	345	1,104	4	8,000,000	3.0	24,000,000
	5C	345	572	2	3,500,000	3.0	10,500,000
Trinity	5G2A	345	1,024	4	8,000,000	3.0	24,000,000

6.6.16 Transmission Line to Nearest Substation

This study assumes the following tie points (to obtain transmission line lengths) for the proposed projects:

- **Yellowtail:** The tie point is assumed to be at the switchyard located along the left abutment adjacent to the Yellowtail Dam.
- **Seminoe:** The tie point is assumed to be at the Seminoe Dam.
- **Trinity:** The tie point is assumed to be at the switchyard just downstream of the Trinity dam.

The unit costs provided in Table 6-16 were derived from Figure 6-21 of EPRI Document No. GS-6669 (1990) assuming 138 kV, 230 kV, 345 kV, or 500 kV and average construction conditions. No attempt was made to establish a firm transmission alignment; instead, an assumed route was utilized. The combined cost for land acquisition and clearing was estimated at $15,000 per acre, assuming a 200-foot right-of-way for each project. An index factor of 3.0 was assumed for this study.

Table 6-16. Transmission Line Characteristics and Estimated Costs

Site		Assumed Length (Miles)	Assumed Voltage (kV)	Transmitted Power (MW)	1988 Est. Line Costs ($/mile)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	10	500	1,660	500,000	3.0	15,000,000
Seminoe	5A2	2	345	859	400,000	3.0	2,400,000
	5A3	2	500	1,104	500,000	3.0	3,000,000
	5C	3	345	572	400,000	3.0	3,600,000
Trinity	5G2A	12	500	1,024	500,000	3.0	18,000,000

6.6.17 Transmission Interconnect Costs

Refer to Chapter 7.

6.6.18 Roads

Project access roads were assumed to be constructed at each of the primary project areas. New roads were assumed to extend from existing roads to major project elements. Assumed roadway lengths and costs are derived from Section 6 of EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an index factor of 3.0.

1988 Cost for New Access Roads

Terrain	$/mile
Steep	439,000
Mild	283,000
Flat	189,000

Table 6-17. Assumed Roadway Lengths and Estimated Costs

Site		Assumed Length of New Access Road (Miles)	Total 1988 Cost for New Access Roads ($)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	5	1,867,000	3.0	5,600,000
Seminoe	5A2	5	1,867,000	3.0	5,600,000
	5A3	5	1,867,000	3.0	5,600,000
	5C	10	3,700,000	3.0	11,100,000
Trinity	5G2A	10	3,700,000	3.0	11,100,000

6.6.19 Lands

Cost estimates do not include any cost for the acquisition of lands.

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Chapter 7
Transmission Evaluation Studies

This chapter describes the evaluation of transmission limits at each of the existing facilities. The evaluation included the cost impacts associated with potential upgrades needed to interconnect each potential pumped storage site to the transmission grid and to operate in the pumping and generating mode while meeting standard operating criteria. This analysis did not consider transmission availability for delivery of the output across the grid, nor did it consider impacts to the system that may be remote from the point of interconnection. This issue must be considered in a future system impact study.

Siemens-PTI's PSS/E Version 33 software was used to represent the pumped storage projects with associated new transmission lines in an approved WECC 2012 Series 2017 Heavy Summer model. Dynamic response of the sites in either pumping or generating mode for disturbances in the area were not considered at this early stage of the review. A more advanced study would require the development of further detailed models for the proposed motor/generator sets, and would be the basis for future work as the projects become more defined.

7.1 Yellowtail 5A

Initial screening of the Yellowtail site indicated this site has the potential for up to 1,660 MW of generation output based on assumed hydrologic, operational, and site conditions. This analysis assumed the pump mode would be a similar value. The predominant voltage class of the transmission grid near the Yellowtail site is 230 kV with several different owners of transmission facilities involved; however, there is also 500 kV transmission within 60 miles of the site. As a result, both 230 kV and 500 kV transmission scenarios were evaluated in this study.

Three transmission options were evaluated: two 230 kV options and one 500 kV option. Transmission Option 1 determines the capability of the existing 230 kV transmission system to serve some amount of generation and pump capability, Option 2 assumes new 230 kV facilities will be used to connect the full generator and pump values, and Option 3 assumes 500 kV facilities will be constructed to accommodate the full design amount. For transmission options 2 and 3, three operating scenarios were evaluated: 1,660 MW in generating mode, 1,660 MW in pumping mode, and a reactive power scenario to indicate reactive requirements during the transition from generating to pumping mode when the transmission is energized with no loading. The results for each operating scenario are summarized below.

7.1.1 Option 1: Interconnection at PPL Switchyard (Minimum Interconnection)

Interconnection at the Yellowtail-PPL (YPPL) 230 kV switchyard is considered a minimum interconnection, and simulation results show overloaded facilities or lines at the YPPL switchyard at about 400 MW of pumping load. Drawings of the project and local 230 kV transmission system around the YPPL switchyard are provided in Volume 2. This minimal option requires 4 miles of a single 230 kV line in rough terrain and a new transmission line bay at the YPPL switchyard. It is assumed that a line bay at the YPPL switchyard would be sufficient for protection of the line and generators, and additional breakers at the pump site for transmission would not be required.

The first system intact limiter shows up in the pumping mode at about 400 MW on the 230 kV line to the Yellowtail-Reclamation switchyard, which is approximately one mile away. Power flow drawings of the three 230 kV interconnection scenarios for the minimum pump and generator load and reactive cases, as listed below, can be found in Volume 2:

- Scenario 1: Yellowtail – 230 connection at PPL near YT – generation at 400 MW
  - No limiter found
- Scenario 2: Yellowtail– 230 connection at PPL near YT – pump at 400 MW
  - Yellowtail – PPL 230 kV line limits
- Scenario 3: Yellowtail– 230 connection at PPL near YT - reactive
  - Small reactive control at new site

An interconnection utilizing this option would likely be limited to opportunity transactions unless further upgrades to system facilities were undertaken. This study assumed that the new outlet lines would be 230 kV rated at 1,200 A capacity with 1272 MCM ACSR at 100 degrees C (Pheasant). This leads to a base rating of 480 MVA for a single circuit 230 kV line.

7.1.2 Option 2: Interconnection at Broadview 230 kV Switchyard

Using the line assumptions above, interconnection at the Broadview 230 kV switchyard would require four 60-mile, 230 kV lines and an additional 500 MVA transformer at Broadview. Two double circuit lines with breakers at each end would provide line and generator protection, leading to 120 miles of double circuit 230 kV line. The study option also assumed eight 230 kV line bays, four each at the new pumped storage site and at the Broadview 230 kV switchyard. In the pumping mode of operation, an additional 500 MVA 500/230 kV transformer is required at Broadview because the large pump load is served from Colstrip Generation via the 500 kV system. Support is also seen from the

230 kV transmission system in Billings. Power flow drawings of the three 230 kV interconnection scenarios for the minimum generation, pump load, and reactive cases, as listed below, can be found in Volume 2:

- Scenario 1: Yellowtail – 230 connection at Broadview – generation at 1,660 MW
  - Loading of existing 230 kV lines increases, and in some cases changes direction, implying that other line loading issues not examined could be identified with a more detailed study. Approximately two-thirds of the flow from the plant flows across the two 500/230 kV transformers located at Broadview onto the 500 kV system, and in this case changes the flow bias across the transformers. About 900 MVar of capacitance is required on the Broadview 230 kV bus to maintain nominal system voltages, with much of this reactive power traveling to the 500 kV system. Further optimization of the VAR placement is possible; however, this scenario meets the project criteria. The capacitor on the 230 kV bus was not shown in the drawings.

- Scenario 2: Yellowtail – 230 connection at Broadview – pump at 1,660 MW
  - Loading on the Alkali creek 230 kV line changes bias, but stays below its ratings. The remaining 230 kV lines remain largely unaffected. Most of the flow contributing to the pumping mode operation is offloaded from the 500 kV system through the Broadview transformers. The 500/230 kV transformer is overloaded for this configuration and another transformer of similar size and impedance will be required. Nearly 300 MVar of capacitance is required on the Broadview 230 kV bus to maintain nominal system voltages with very little of this flowing into the 500 kV system. This illustrates the heavy loading and less than optimal performance of the 230 kV option. Further optimization of reactive placement is possible; however, because this scenario meets line loadings and voltage limit criteria, further analysis was not performed. The capacitor on the 230 kV bus is not shown in the drawings.

- Scenario 3: Yellowtail – 230 connection at Broadview – reactive
  - Reactive charging is relatively minor when changing from pumping to generating modes.

7.1.3 Option 3: Interconnection at Broadview 500 kV Switchyard

This study option assumes the new outlet lines would be 500 kV rated at 1,960 A capacity with two conductor bundled Rail 954 ACSR conductors. This leads to a base rating of 1,700 MVA for a single circuit 500 kV line. Interconnection at the Broadview 500 kV switchyard would require one 500 kV bay at the Broadview 500 kV bus, and one 500 kV line approximately 60 miles connecting to the Yellowtail 5A site with new 500 kV GSU. Power flow drawings of the three 500 kV interconnection scenarios for the minimum generation, pump load, and reactive scenarios, as listed below, can be found in Volume 2:

- Scenario 1: Yellowtail– 500 connection at Broadview – gen 1,024 MW
  - Loading on the 230 kV lines connected to the Broadview 230 kV bus increases; however, not as much as with the 230 kV option. The transformer bias change is eliminated for this option.

- Scenario 2: Yellowtail – 500 connection at Broadview – pump 1,660 MW
  - The worst case power flow change is 125 MW. All line loadings and system voltages remain within ratings for this case. No additional capacitance is needed for this option.

- Scenario 3: Yellowtail – 500 connection at Broadview – reactive
  - Approximately 150 MVars of reactors will be needed to compensate for the line charging at 500 kV when changing from pumping to generating modes.

7.1.4 Outcome

The powerflow and desktop analyses show that the 500 kV transmission option is superior to the 230 kV transmission options considered for Yellowtail 5A. A single-circuit 500 kV line provides better voltage regulation, reduced losses, and is slightly less expensive than the multiple 230 kV circuits that were considered as Option 2. The 230 kV full output Option 2 shows reactive equipment additions at Broadview are required.

The location of pump/generation plant is not firm at this time. To determine line distance estimates for new outlet transmission, the plant location was assumed to be near the shore of the existing reservoirs between the new proposed upper reservoir and the existing lower reservoir. Cost opinions are detailed in the following table for the three different transmission options. Cost of the GSU to get the generator/pump units to transmission voltages was not included.

Table 7-1. Yellowtail 5A Transmission Cost Opinions

Characteristic	Option 1: 230 kV with Minimum Interconnection ~400 MW Limit	Option 2: 230 kV Interconnection 1,660 MW	Option 3: 500 kV Interconnection 1,660 MW
Line description for construction	Single circuit 230 kV @ 4 miles	Two double circuit 230 kV @ 60 miles	Single circuit 500 kV @ 60 miles
Costs (million)	$2.0	$120.0	$120.0
Substation bay additions	Single line bay at PPL switchyard	Four line bays at new plant and Broadview 230 kV	Single line bay at Broadview 500 kV switchyard
Costs (million)	$0.4	$4.0	$1.0
Substation reactive equipment additions	none	3 x 300 MVar Capacitor on 230 kV bus at Broadview	3 x 50 MVar Reactor on 500 kV bus at Broadview
Costs (million)	0	$9.0	$1.5
Transformer additions	none	500 MVA 500/230 kV transformer at Broadview sub	none
Costs (million)	0	$10.0	0
Total Costs (million)	$2.4	$143	$122.5

7.2 Seminoe 5A2, 5A3, and 5C

Initial screening studies indicated the Seminoe sites have potential installed capacities in the order of 900 to 1,000 MW of generation output based on assumed hydrologic, operational, and site conditions. This analysis assumes capacity of 957 MW both in the generation and pump mode. The predominant voltage class of the transmission grid near the sites is 230 kV located about 7 miles away at Miracle Mile; however, there is also 500 kV transmission within 40 miles of the study area. As a result, both 230 kV and 500 kV transmission scenarios were evaluated in this study.

Three different transmission options were evaluated: two 230 kV options and one 500 kV option. Transmission Option 1 determines the capability of the existing 230 kV transmission system to serve some amount of generation and pump capability, Option 2 assumes new 230 kV facilities will be used to connect the full generator and pump values, and Option 3 assumes 500 kV facilities will be constructed to accommodate the full design amount. For each transmission option, three operating scenarios were evaluated: a 957 MW in generating mode, 957 MW in pumping mode, and a reactive power scenario to indicate reactive requirements during the transition from generating to pumping mode when the transmission is energized with no loading. The results for each operating scenario are summarized below.

7.2.1 Option 1: Interconnection at Miracle Mile Switchyard (Minimum Interconnection)

Interconnection at the Miracle Mile switchyard would be considered a minimum interconnection, and would overload the transformers at the switchyard at about 250 MW of pumping load. Drawings of the local pump/generation and local 230 kV area around the sites' switchyards are shown in Volume 2. This option requires about 7 miles of a single 230 kV line in rough terrain and a new transmission line bay at Miracle Mile switchyard. It is assumed that a line bay at Miracle Mile switchyard would be sufficient for protection of the line and generators, and additional breakers at the pump site for transmission would not be required. The first system intact limiter shows up in the pumping mode at about 250 MW on the 230 kV transformers between the 230 and 115 kV Miracle Mile switchyards. Adding transformation would result in overloads on the 115 kV system, which makes this option too small to consider further. Powerflow drawings of the three 230 kV interconnection options for the minimum load and reactive scenarios are found in Volume 2 and are labeled as follows:

- Scenario 1: Seminoe – generation at 250 MW
  - No limiter found.
- Scenario 2: Seminoe – pump at 250 MW
  - Both 230/115 kV transformers at or near limits.
- Scenario 3: Seminoe – reactive
  - Small reactive control action at new site.

An interconnection utilizing this option would likely be limited to opportunity transactions unless significant upgrades to local transmission system facilities were undertaken. The assumption was made that the new outlet lines would be 230 kV rated at 1,200 A capacity with 1272 MCM ACSR at 100 degree C (Pheasant). This leads to a base rating of 480 MVA for a single circuit 230 kV line.

7.2.2 Option 2: Interconnection at Aeolus 230 kV Switchyard

Using the same line assumptions as above, interconnection at the Aeolus 230 kV switchyard would require two 40-mile, 230 kV lines. One double circuit line with breakers at each end would provide line and generator protection, leading to 40 miles of double circuit 230 kV line. The study also assumed four 230 kV line bays: two each at the new Seminoe sites and at the Aeolus 230 kV switchyard. Powerflow drawings of the three 230 kV interconnection scenarios for the minimum generation, pump load, and reactive cases are found in Volume 2 and are labeled as follows:

- Scenario 1: Seminoe – Aeolus 230 kV connection – generation 957 MW
  - Loading of existing 230 kV lines and transformers increases, but does not exceed ratings. The generator is absorbing a high level of MVars (+330) from the switched shunt capacitors near Aeolus 500 kV bus to maintain nominal system voltages; however, existing capacitance in the area is sufficient to compensate for voltage regulation in this case. This sizing was derived by combining reactive equipment on 500 kV buses at Aeolus and Anticline. Further optimization of reactive placement is needed because different system transfers and wind generation levels may show different reactive components required at Aeolus; however, this scenario meets line loadings and voltage limit criteria, so further analysis was not needed.
- Scenario 2: Seminoe – Aeolus 230 kV connection – pump 957 MW
  - Loading on the system remains within ratings. Very little capacitance is required on the Aeolus 230 kV bus to maintain nominal system voltages. 100 MVars will be required to support the 957 MW pump load.
- Scenario 3: Seminoe – Aeolus 230 kV connection – reactive
  - Reactive charging is relatively minor due to the strong reactive sources at Aeolus.

7.2.3 Option 3: Interconnection at Aeolus 500 kV Switchyard

This study option assumed the new outlet lines would be 500 kV rated at 1,960 A capacity with two conductor-bundled Rail 954 ACSR conductors. This leads to a base rating of 1,700 MVA for a single circuit 500 kV line. Interconnection at the Aeolus 500 kV switchyard would require one 500 kV bay at the Aeolus 500 kV bus, and one 500 kV line about 40 miles long with a 500 kV GSU at the site. Powerflow drawings of the three 500 kV interconnection scenarios for the minimum generation, pump load, and reactive cases are found in Volume 2 and are labeled as follows:

- Scenario 1: Seminoe – Aeolus 500 kV connection – generation 957 MW
  - Loading on the lines and the 500/230 kV transformers connected to the Aeolus 230 kV bus remain within ratings.
- Scenario 2: Seminoe – Aeolus 500 kV connection – pump 957 MW
  - Loading remains within ratings for this load flow case.

- Scenario 3: Seminoe – Aeolus 500 kV connection – reactive
  - Reactive charging is relatively minor.

7.2.4 Outcome

The powerflow and desktop analyses show that the 500 kV transmission option and the 230 kV transmission option perform about equally well for the Seminoe sites; however, the 500 kV option costs nearly twice as much as the 230 kV option. In this scenario, the 230 kV option requires only a single double circuit 230 kV line for a significant cost savings.

The location of pump/generation plant is not firm at this time. To determine line distance estimates for new outlet transmission, the plant location was assumed to be near the shore of the existing reservoirs between the new proposed upper reservoir and the existing lower reservoir. Cost opinions are detailed in the following table for the three different transmission options. The cost of the GSU to get the generator/pump units to transmission voltages was not included.

Table 7-2. Seminoe 5A2, 5A3, and 5C Transmission Cost Options

Characteristic	Option 1: Minimum Interconnection ~250 MW	Option 2: 230 kV Interconnection 957 MW	Option 3: 500 kV Interconnection 957 MW
Line description for construction	Single circuit 230 kV @ 7 miles	One double circuit 230 kV @ 40 miles	Single circuit 500 kV @ 40 miles
Costs (million)	$3.5	$40.0	$80.0
Substation bay additions	Single line bay at Miracle Mile switchyard	Two line bays at new plant and Broadview 230 kV	Single line bay at Broadview 500 kV switchyard
Costs (million)	$0.4	$1.6	$1.0
Substation reactive equipment additions	none	none	none
Costs (million)	0	0	0
Transformer additions	none	none	none
Costs (million)	0	0	0
Total Costs (million)	$3.9	$41.6	$81.0

7.3 Trinity 5G2A

Initial screening showed the Trinity 5G2A site has the potential for up to 1,024 MW of generation output based on assumed hydrologic, operational, and site conditions. This analysis assumes the pump mode will be a similar value. The predominant voltage class of the transmission grid near the Trinity 5G2A site is 230 kV located about 15 miles away at Trinity power plant; however, there is also 500 kV transmission within 60 miles of the study area. As a result, both 230 kV and 500 kV transmission scenarios were evaluated in this study.

Three different transmission options were evaluated: two 230 kV options and one 500 kV option. Transmission Option 1 determines the capability of the existing 230 kV transmission system to serve some amount of generation and pump capability, Option 2 assumes new 230 kV facilities will be used to connect the full generator and pump values, and Option 3 assumes 500 kV facilities will be constructed to accommodate the full design amount. For each transmission option, three operating scenarios were evaluated: a 1,024 MW in generating mode, 1,024 MW in pumping mode, and a reactive power scenario to indicate reactive requirements during the transition from generator to pumping mode when the transmission is energized with no loading. The results for each operating scenario are summarized below.

7.3.1 Option 1: Interconnection at Trinity Switchyard (Minimum Interconnection)

Interconnection at Trinity switchyard would be considered a minimum interconnection, and would overload the Trinity-JF Carr 230 kV line at about 200 MW of pumping load. Power flow drawings of the local pump/generation and local 230 kV area around the Trinity switchyard are shown in Volume 2 with the drawings listed below. This option requires about 15 miles of a single 230 kV line in rough terrain and a new transmission line bay at Trinity switchyard. It is assumed that a line bay at Trinity switchyard would be sufficient for protection of the new line and generators, and additional breakers at the pump site for transmission would not be required. The first system intact limiter shows up in the generation mode at about 200 MW on the 230 kV line from Trinity to JF Carr. Power flow drawings are provided in Volume 2 of the three 230 kV interconnection scenarios for the minimum load and reactive cases as follows:

- Scenario 1: Trinity – proposed 230 interconnection at Trinity – generation at 200 MW
  - 230 kV Trinity – JF Carr line
- Scenario 2: Trinity – proposed 230 interconnection at Trinity – pump at 200 MW
  - No limiter found
- Scenario 3: Trinity – proposed 230 interconnection at Trinity – reactive
  - No limiter found

An interconnection utilizing this option would likely be limited to opportunity transactions unless further upgrades to system facilities were undertaken. This study assumed that the new outlet lines would be 230 kV rated at 1,200 A capacity with 1272 MCM ACSR at 100 degrees C (Pheasant). This leads to a base rating of 480 MVA for a single circuit 230 kV line.

7.3.2 Option 2: Interconnection at Olinda 230 kV Switchyard

Using the same line assumptions above would require three lines. However, the required line rating is 512 MVA for each of the two proposed lines, requiring a larger conductor rated for about 1,300 A such as Nuthatch rather than Pheasant. Interconnection at the Olinda 230 kV switchyard would require two 60-mile, 230 kV lines for interconnection. One double-circuit line with breakers at each end would provide line and generator protection, leading to 60 miles of double circuit 230 kV line. The study also assumed four 230 kV line bays: two each at the new PSH site and at the Olinda 230 kV switchyard. Power flow drawings as provided in Volume 2 of the three 230 kV interconnection scenarios for the minimum load and reactive cases are as follows:

- Scenario 1: Trinity – proposed 230 interconnection at Olinda - 1,024 MW generation
  - Loading of the existing 500 kV Olinda-Maxwell line and the Olinda 525 MVA-500/230 kV transformer exceeds ratings. The line rating must be increased from 1,700 MVA to 1,933 MVA. The transformer rating must be increased from an existing 525 MVA to 677 MVA. The cost of a new Olinda transformer is included in the table provided below, but because the limiting element of the 500 kV line is unknown and may be as minor as a piece of terminal equipment or as major as line conductor, no additional costs are included. Existing capacitance in the area should be sufficient to compensate for voltage issues in this case.
- Scenario 2: Trinity – proposed 230 interconnection at Olinda - 1,024 MW pump
  - Loading on the system remains within ratings. Very little capacitance is required to be on to maintain nominal system voltages.
- Scenario 3: Trinity – proposed 230 interconnection at Olinda - reactive
  - Reactive charging is relatively minor.

7.3.3 Option 3: Interconnection at Olinda 500 kV Switchyard

This study assumed that the new outlet lines would be 500 kV rated at 1,960 A capacity with two conductor bundled Rail 954 ACSR conductors. This leads to a base rating of 1,700 MVA for a single circuit 500 kV line. Interconnection at the Olinda 500 kV switchyard would require one 500 kV bay at the Olinda 500 kV bus, and one 500 kV line about 60 miles long. This case overloads the Olinda-Maxwell 500 kV line in the full generation mode at Trinity PSH by nearly 400 MVA. The limiting facility is unknown, so a cost opinion for mitigating this overload was not included in the table below. If the overload is caused by a minor piece of station equipment, the cost may be less than

$1,000,000; however, if the overload is a result of reaching the maximum conductor limit, that will require reconductoring the line and possibly replacing structures in certain locations. This cost is indeterminate without additional information, but may be many millions to complete. Power flow drawings as provided in Volume 2 of the three 500 kV interconnection scenarios for the minimum load and reactive cases are as follows:

- Scenario 1: Trinity – proposed 500 interconnection at Olinda – generation 1,024 MW
  - Loading on the Olinda-Maxwell 500 kV line loads to about 2,100 MW. The line rating is 1,700 MVA in this model; therefore, generation will need to be limited or additional facility upgrades of the line will be required.
- Scenario 2: Trinity – proposed 500 interconnection at Olinda – pump 1,024 MW
  - Loading remains within ratings for this load flow case.
- Scenario 3: Trinity – proposed 500 interconnection at Olinda – reactive
  - Reactive charging is relatively minor.

7.3.4 Outcome

The powerflow and desktop analyses show that the 500 kV transmission option and the 230 kV transmission option perform equally well for the Trinity 5G2A site. The location of the pump/generation plant is not firm at this time. To determine line distance estimates for new outlet transmission, the plant location was assumed to be near the shore of the existing reservoirs between the proposed upper reservoir and the existing lower reservoir. Cost opinions are detailed in the following table for the three different transmission options. Cost of the GSU to get the generator/pump units to transmission voltages was not included. The analysis of the interconnection at the Olinda 230/500 kV Substation did not consider transmission deliverability across the grid which may be an issue in this location. The transmission system comprising the California-Oregon Border interface is often congested due to high imports from the northwest, so the addition of this large project will require additional detailed studies to determine regional transmission system impacts.

Table 7-3. Trinity 5G2A Transmission Cost Options

Characteristic	Option 1: Minimum Interconnection ~200 MW	Option 2: 230 kV Interconnection 1,024 MW	Option 3: 500 kV Interconnection 1,024 MW*
Line description for construction	Single circuit 230 kV @ 15 miles	One double circuit 230 kV @ 60 miles	Single circuit 500 kV @ 60 miles
Costs (million)	$7.5	$60.0	$120.0
Substation bay additions	Single line bay at Trinity switchyard	Two line bays at new plant and Olinda 230 kV	Single line bay at Olinda 500 kV switchyard
Costs (million)	$0.4	$1.6	$1.0
Transformer additions	none	Second 525 MVA-500/230 kV transformer at sub	none
Costs (million)	0	$9.0	0
Total Costs (million)	$7.9	$70.6	$121.0

*Additional 500 kV upgrades will be required to mitigate 500 kV line overload.

Chapter 8
Cost Opinion and Project Schedules

8.1 Direct Cost Estimate

A summary of the estimated direct cost (i.e., cost of materials, equipment, and labor for construction of structures, and supply and installation of permanent equipment) for each pumped storage project is provided in Table 8-1. It should be noted that these costs only represent an AACE Class 4 cost opinion based on very conceptual layout information and derived from cost curves provided by EPRI's Pumped Storage Planning and Evaluation Guide, escalated to 2012 dollars.

8.2 Indirect Costs

Indirect costs generally run between 15 and 30 percent of direct costs, and are largely dependent on configuration, environmental/regulatory, and ownership complexities. An allowance of 20 percent has been allocated for indirect costs, including:

- Preliminary engineering and studies (planning studies, environmental impact studies, investigations);
- License and permit applications and processing;
- Detailed engineering and studies;
- Construction management, quality assurance, and administration; and
- Bonds, insurances, taxes, and corporate overheads.

Table 8-1. Opinion of Probable Cost Summary (Million $)

	Yellowtail 5A	Seminoe 5A2	Seminoe 5A3	Seminoe 5C	Trinity 5G2A
Approximate Installed Capacity (MW)	1,660	859	1,104	572	1,024
Assumed Number of Units	4	4	4	2	4
Assumed Static Head (ft)	1,562	872	1,022	909	775
Assumed Usable Storage Volume (acre-ft)	12,081	11,202	12,277	7,145	15,022
Energy Storage (MWH)	16,601	8,591	11,036	5,716	10,245
Hours of Storage	10	10	10	10	10
Tunnel Diameter (ft)	1 @ 31 ft	1 @ 38 ft	1 @ 37 ft	1 @ 31 ft	2 @ 30 ft
Penstock Diameter (ft)	4 @ 13 ft	4 @ 15 ft	4 @ 14 ft	2 @ 17 ft	4 @ 17 ft
Land and Land Rights	See Note 1	See Note 1	See Note 1	See Note 1	See Note 1
Upper Reservoir and Dams					
Dam	$134.71	$157.50	$166.05	$162.70	$65.52
Stream Diversion	$5.00	$5.00	$5.00	$5.00	$5.00
Upper Reservoir Liner	$4.00	-	-	-	-
Spillway	$5.00	$5.00	$5.00	$5.00	$5.00
Civil Works					
Power Station - Civil	$199.21	$164.95	$180.99	$125.75	$225.39
Upper Reservoir Intake	$6.60	$12.00	$11.70	$6.60	$13.20
Vertical Shaft	$26.10	$12.60	$19.95	$12.35	$26.51
Horizontal Power Tunnel	$65.10	$96.00	$60.00	$46.50	$144.00
Penstocks	$27.00	$15.12	$18.00	$9.72	$20.28
Draft Tube Tunnels & DT Gates	$24.90	$23.10	$21.00	$14.70	$28.80
Tailrace Tunnels	$51.60	$73.50	$52.50	$31.35	$109.20
Discharge Structure & Channel	$39.00	$35.40	$39.00	$22.50	$49.20
Surge Chamber	-	$66.10	-	-	$98.64
Draft Tube / Transformer Gallery	$26.00	$26.00	$26.00	$13.00	$26.00
Access Tunnels	$21.60	$18.72	$18.72	$18.72	$19.44
Underground Haul Tunnels	$12.00	$12.00	$12.00	$12.00	$12.00
Site Roads	$5.60	$5.60	$5.60	$11.10	$11.10
Miscellaneous civil works and structures	$25.00	$25.00	$25.00	$25.00	$25.00
Power Plant Equipment	$697.24	$463.92	$573.87	$310.93	$545.03
Switchyard	$42.00	$24.00	$24.00	$10.50	$24.00
Transmission - Plant to Interconnect	$15.00	$2.40	$3.00	$3.60	$18.00
Transmission - Infrastructure Upgrades	$122.50	$41.60	$41.60	$41.60	$70.60
Subtotal	$1,555.16	$1,285.50	$1,308.99	$888.62	$1,541.90
Temporary Facilities & Site Prep	$77.76	$64.27	$65.45	$44.43	$77.10
Subtotal Direct Costs	$1,632.92	$1,349.77	$1,374.43	$933.05	$1,619.00
Contingency (20%)	$326.58	$269.95	$274.89	$186.61	$323.80
Indirect Costs (20%)	$326.58	$269.95	$274.89	$186.61	$323.80
Total Construction Costs (2) (3)	$2,286.08	$1,889.68	$1,924.21	$1,306.27	$2,266.60
Estimated Cost ($/MW)	$1.38	$2.20	$1.74	$2.29	$2.21
Cost Ranking $/MW	1	4	2	5	3

1. Costs not included at this level of analysis.
2. Cost estimates are AACE Class 4 estimates with 20 percent contingency.
3. Cost estimates are in 2012 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.

8.3 Life Cycle Costs

8.3.1 Annual Routine Operations and Maintenance Costs

EPRI provides the following equation for estimating the annual O&M costs for a pumped storage project in 1985 dollars:

O&M Costs ($/yr) = 34,730 x $C^{0.32}$ x $E^{0.33}$

Where: C = Plant Capacity (MW)
E = Annual Energy (GWh)

Table 8-2 represents annual O&M costs assuming 6 hours of operation per day for 365 days per year. Assuming an average annual inflation rate of 3 percent, the EPRI annual O&M cost relationship escalates by a factor of 2.5.

Table 8-2. Estimated O&M Costs

Site		Installed Capacity (MW)	Annual Energy (GWh)	1985 O&M Costs ($)	Index Factor	2012 Total Est. Costs ($)
Yellowtail	5A	1,660	3,636	5,600,000	2.5	14,000,000
Seminoe	5A2	859	1,881	3,600,000	2.5	9,000,000
	5A3	1,104	2,417	4,300,000	2.5	10,750,000
	5C	572	1,252	2,800,000	2.5	7,000,000
Trinity	5G2A	1,024	2,244	4,100,000	2.5	10,250,000

These expenses include annual FERC fees, labor, contracts, consumables, inventory, and other routine operation and maintenance activities.

8.3.2 Bi-Annual Outage Costs

Units should be taken out of service for approximately three weeks every two years for routine bi-annual inspection and maintenance at a cost of approximately $150,000 (per unit).

8.3.3 Major Maintenance

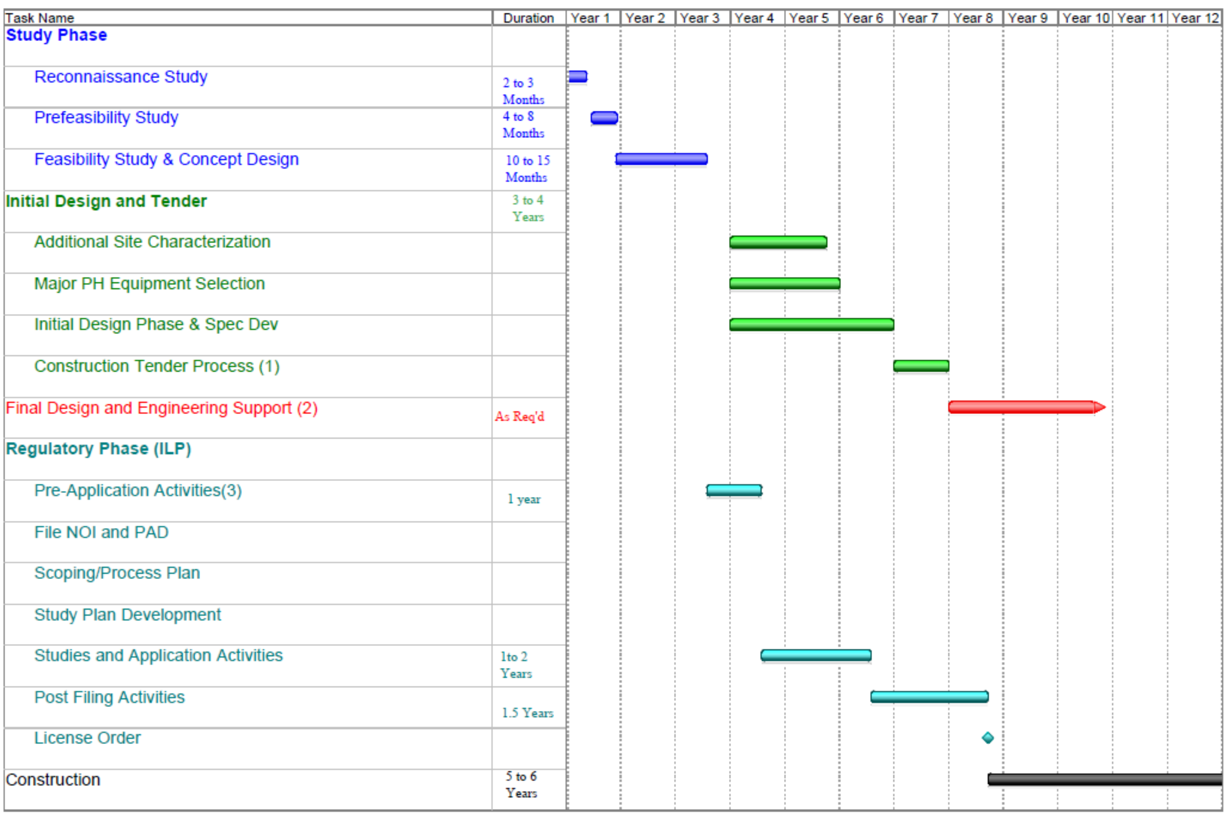
Approximately $1,500,000 (per unit) should be budgeted for a major unit overhaul around year 20. The unit would be out of service for approximately six to eight months.

8.4 Project Schedule

The project schedule is dependent on many factors such as technology, site characteristics and subsurface conditions, as well as environmental and regulatory complications. However, the following development schedule could be reasonably assumed (Figure 8-1):

Phase	**Schedule**
Engineering studies, site characterization, and permits	2+ years
Detailed engineering and construction planning	2+ years
Construction and startup testing	3-5 years

Figure 8-1. Typical Pumped Storage Development Schedule



Notes:
(1) Assumes construction bid documents are released in advance of final design.
(2) Assumes engineering continues through tendering process as well as construction
(3) Pre-Application activities could be advanced depending on the owner's appetite for risk prior to completion of feasibility study

Chapter 9
Operational Studies

9.1 Operations Model Description

This section presents an overview of the development of an operations model for analyzing the operational potential of prospective pumped storage. The operations model was used to test potential operation schedules for pumping and power generation that could yield income benefits from electricity arbitrage and ancillary services. The operations model is fundamentally a mass balance model that tracks the storage of the new reservoir and existing forebay reservoir, as well as any pumped or generation flows exchanged between the two reservoirs, for each model timestep. Operation schedules – the timing and duration of pumped and generation operation – can be specified to take advantage of electricity price variability during a day to maximize revenue. The operations model also includes the assessment of income generated from 4 ancillary services: regulation up and down, spinning and non-spinning reserves.

Schematic diagrams of each site, including information on storage capacities of downstream reservoirs and proposed new reservoirs, installed turbine capacities and operating rules were compiled during the model development to identify operating boundaries. The diagrams of each pumped storage site are presented in Figures 9-1 through 9-3. The figures only show Seminoe 5A3 because it is analyzed in more detail in this section as the site with the highest income and lowest estimated cost per MW of the three Seminoe configurations. The operations model was simplified to include only the new reservoir and its forebay reservoir and the pumped flow, or power generation flow, between these two reservoirs.

Figure 9-1. Schematic of Yellowtail Pumped Storage Facility

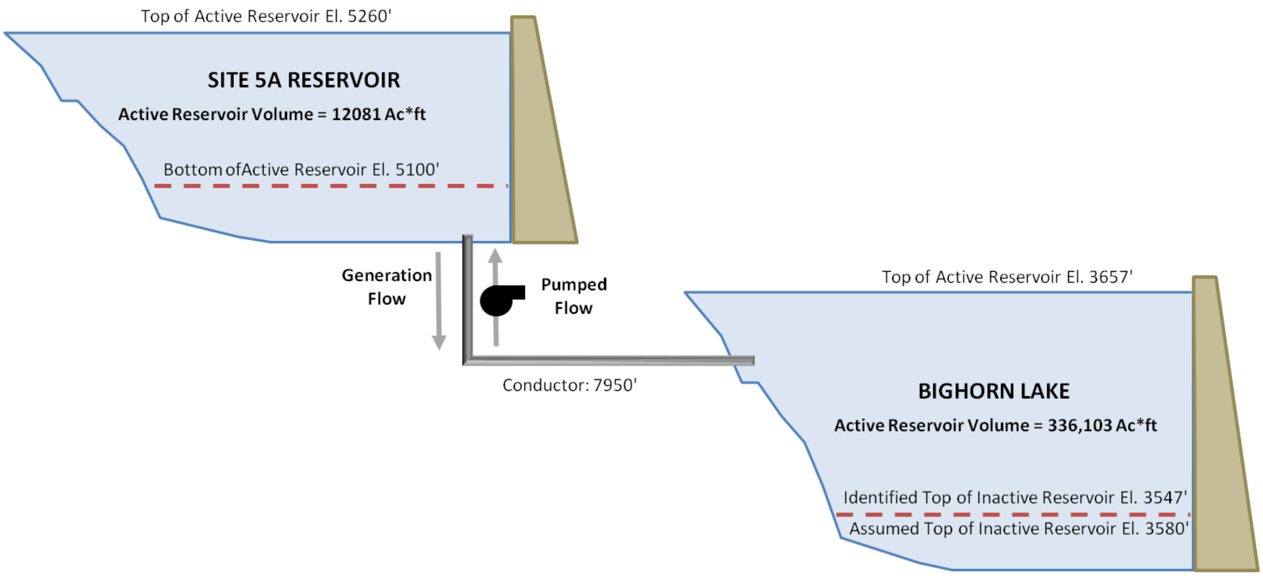


Figure 9-2. Schematic of Seminoe Pumped Storage Facility

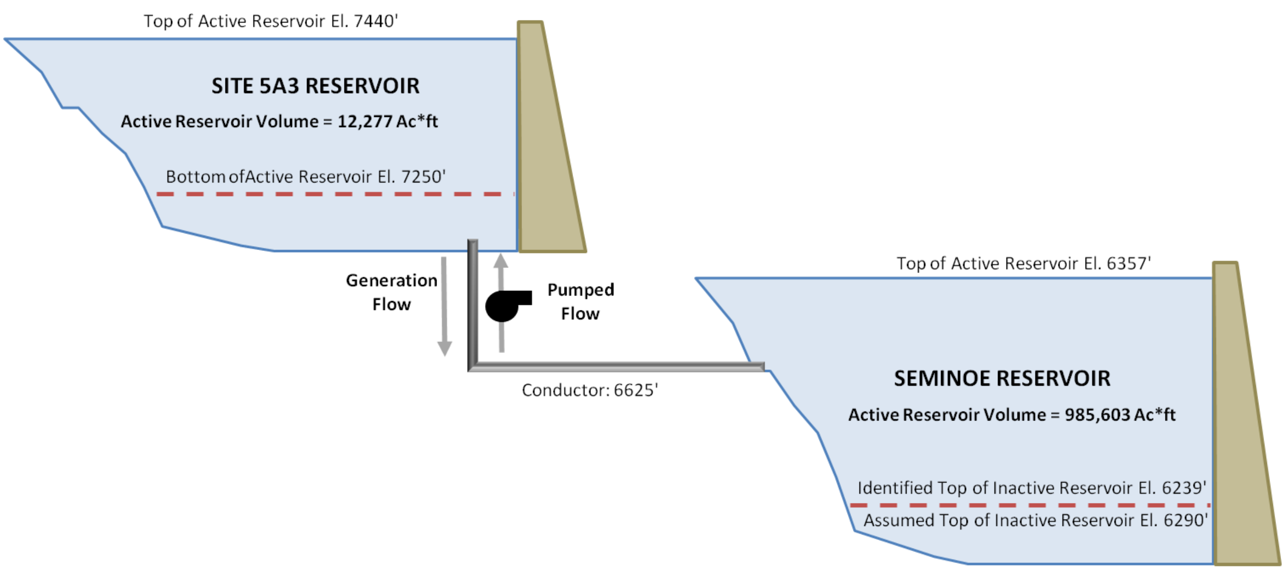
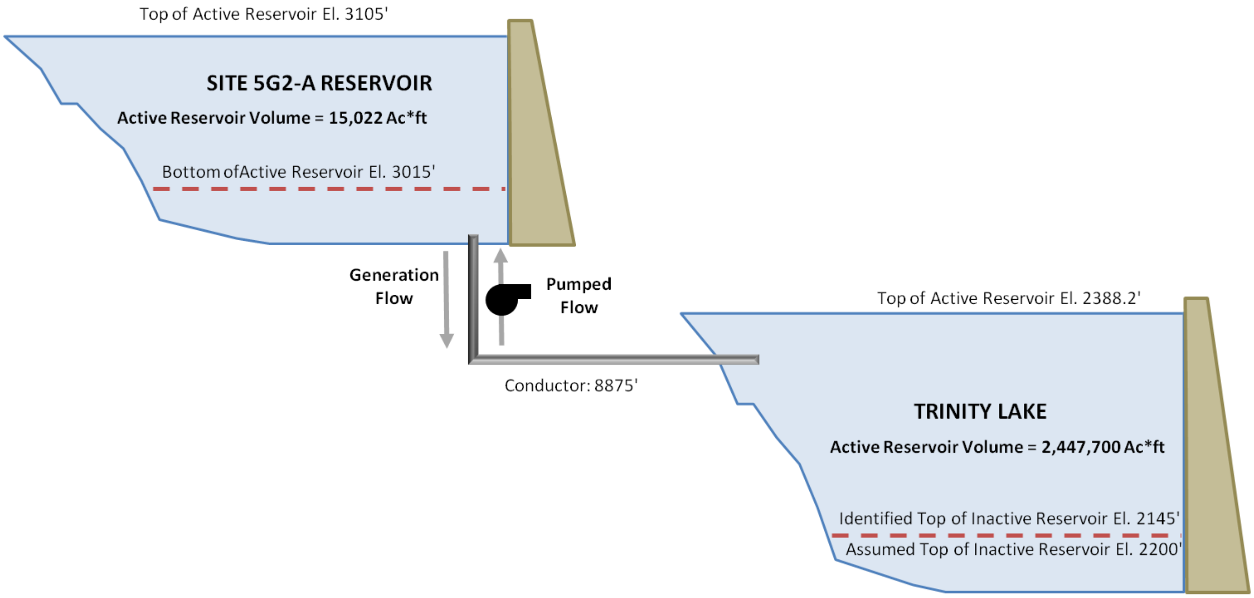


Figure 9-3. Schematic of Trinity Pumped Storage Facility



The operations model uses an hourly timestep to account for fluctuations in energy prices and scheduling of pumps and turbine operation. Simulations are run for one week to incorporate “typical week” energy pricing data available from the Northwest Power and Conservation Council (See Chapter 10 for further discussion). Finally, typical weeks for each month of the year are simulated to assess seasonal differences in optimal pump/turbine operations (triggered by seasonal pricing differences). By manipulating the hourly pump/turbine schedules, primarily in response to the hourly energy pricing data, an optimal schedule that maximizes income was developed for each month. The new reservoir is assumed to fill and empty over the course of a day, depending on the region’s energy price structure.

Other variables investigated in the operations model analysis included the amount of storage dedicated to arbitrage relative to ancillary services, the distribution of both storage pools and pump/turbine capacity amongst the individual ancillary services, hydrology (in the form of observed variability in forebay reservoir water elevations), and variability in pricing. Because of the large number of variables used in the operations model and the non-linear relationship between changes in the variables and the resulting income generated from the project, it was determined that an automated optimization approach would not be feasible. Instead, the model was manually optimized using a stepwise approach. For any given hydrology and month simulated, the size of the ancillary pool is first adjusted to achieve the maximum income potential. Arbitrage is used in some months based on the ratio between peak and off-peak prices. After the arbitrage/ancillary service distribution is set, the schedule of pumping and generation is then adjusted to identify any additional income benefits. Finally, the distribution of storage and pump/turbine capacity amongst the individual ancillary services is adjusted to maximize the final system income.

9.1.1 Modeling Ancillary Services

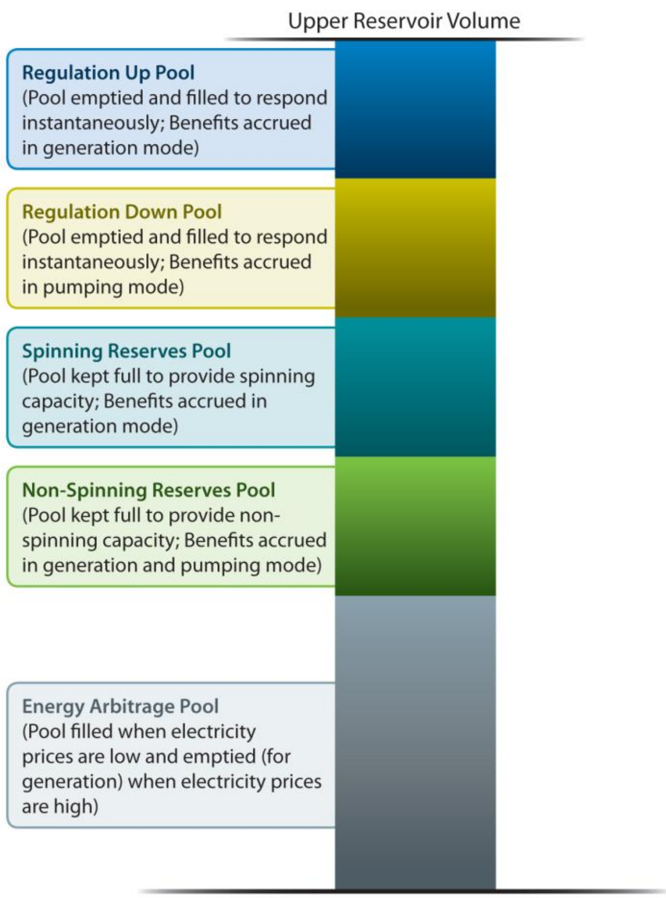
The operations model estimates benefits from both energy arbitrage and ancillary services. Providing ancillary services is a relatively new market that could face a large increase in demand in the future, particularly with new renewable energy sources coming online in response to state RPS. The operations model assumes that a portion of the new reservoir would be dedicated to providing ancillary services instead of being operated for energy arbitrage. Ancillary service income is based on available price data from California Independent Systems Operators (CAISO). Chapter 10 describes ancillary service price data in detail. The following assumptions were used as a basis for the approach to programming ancillary services in the operations model:

- Reservoir volume is split between arbitrage and ancillary services. The user can set the percent allocation (e.g., 90% dedicated to arbitrage, 10% reserved for ancillary services). The reserved ancillary service volume is further split into spinning, non-spinning, regulation up, and regulation down services.
- Initially, the volume of storage dedicated to these four ancillary services was split evenly but the percentages were adjusted as part of the manual optimization process.
- Pump/turbine capacity is also divided between arbitrage and ancillary services, as well as amongst the individual ancillary services. The distribution of pumping capacity adjusts the capacity dedicated to regulation down services and for refilling the pools emptied by generation. Likewise, the distribution of generating capacity affects the capacity dedicated to spinning, non-spinning, and regulation up services as well as the emptying of the regulation down pool. The distribution of pump/turbine capacity was initially split evenly amongst the ancillary services but the distribution was adjusted as part of the manual optimization process, based primarily on the pricing structure of the individual ancillary services.
- The regulation down pool and pumping capacity can provide benefits by pumping water instantaneously when energy supplies exceed market demand (for example, on a windy night when wind is generating substantial power but there is little demand).
- The regulation up pool and generating capacity can provide benefits by increasing power generation instantaneously while the system is already in generation mode (but not running at full capacity).

- The spinning reserves pool provides spinning services while the system is in generation mode. The turbines used for this service are kept in synchronous condense mode (spinning in air) to allow a rapid increase in generation.
- The non-spinning reserves pool provides services when needed, but the generators would not be spinning in case energy is needed. This pool cannot produce energy as rapidly as spinning, but the pump storage system can shift into non-spinning reserves generation from either generation or pumping mode.

The baseline model simulates calls on the ancillary market. In other words, the operations model estimates income derived from the availability of ancillary services based on operating characteristics as well as income from deployed services, which would be made upon request by ISOs. A graphical presentation of the reservoir volume pools is presented in Figure 9-4.

Figure 9-4. Conceptual Graph of Arbitrage and Ancillary Services Pools as Programmed in Model



9.1.2 Input Data and Model Assumptions

The model uses a variety of input data to simulate historic conditions in the forebay reservoir with the pump and generation activity of the pumped storage system superimposed on it. The following input data and user input is needed to set up the operations model:

- Historic water levels in the forebay reservoir. The user specifies a year from the historic period and forebay water levels are pulled in from the historical water levels data for each month of the simulation.
- Physical characteristics of the pump storage system. The user must enter data for conveyance facilities, the maximum and minimum pump and turbine flows, and pump and generation efficiency.
- Arbitrage pool. The user must enter a percentage of the total new reservoir volume that is dedicated to energy arbitrage. The remainder of the reservoir volume would be used to provide ancillary services.
- Ancillary services price structure. The user must select among various options for base year and escalation of ancillary service prices.
- Minimum and maximum allowable elevation. The user must enter the bottom of the active conservation pool for the existing forebay and the top of the active conservation pool for the new reservoir.
- Ancillary services pool and capacity. The user can allocate the ancillary pool volume among the four services: regulation up, regulation down, spinning reserves, and non-spinning reserves. The user can also dedicate pump and turbine capacity to each ancillary service. The default setting is an equal proportion dedicated for all services, but the distribution was adjusted as part of the manual optimization process.
- Hourly operations schedule (timing and duration of pumping and generation). The user must enter a specified pumping and generating schedule for weekdays and weekends.
- Ancillary service calls. The user can adjust the calls on ancillary services based on a percentage of total ancillary service potential.

9.1.3 Scenario Descriptions

The baseline operations model simulations used a consistent set of parameters for all of the pumped storage sites considered to support an accurate comparison of site feasibility. Table 9-1 shows the standard set of parameters included in the operations model.

Table 9-1. Operations Model Parameters

Model Parameter	Parameter Value Used in Baseline Simulations
Hydrological Simulation Year	2002
Benefit Simulation Year	2032
Energy Prices	Without CO2
Arbitrage Pool Volume	0% - 100%
Ancillary Base Year	2011 (High)+ user specified escalation
Ancillary Price Escalation	3.0% per Year

The baseline scenario also uses the following assumptions for deployment of ancillary services. If ancillary services are deployed, the income would include both the ancillary service value and the value of energy at the time it is needed. This would increase the overall income of the pumped storage project. The need for ancillary services is based on many operating factors; therefore, there is a lot of uncertainty for when they would be deployed. Available data suggests the following frequency (percent of hourly ancillary deployment) at which these ancillary services are deployed. The high percentage is used for the modeling.

- Percent deployment of regulation services: 50-70%
- Percent deployment of spinning reserve: 20-40%
- Percent deployment of non-spin: 10-20%

In addition to these static parameters, there are model settings that are site specific, namely the regional markets from which the energy prices are used. The markets used are Montana (Yellowtail), California (Trinity), and Wyoming (Seminoe).

The facilities that make up the individual pumped storage configurations are discussed in detail in Chapter 2.

In addition to the baseline Operations Models where operation schedule and amount of volume dedicated to arbitrage power generation were manipulated to maximize income, five operational analysis scenarios were developed to assess the model sensitivity to a range of parameters.

9.1.3.1 Scenario 1: Varied Hydrologic Conditions (Wet/Dry Years)

This scenario assesses the impact of changes in hydrology on the performance of the pump-storage system. This scenario considers whether low forebay reservoir water levels in dry years could prevent full usage of the pumped storage facility because water levels could drop below minimum operating levels. It also estimates how changing water levels in the forebay reservoir could affect the amount of power generated. Historic hydrology, in the form of historic forebay reservoir water level data, was used and the model was tested using dry and wet year settings.

9.1.3.2 Scenario 2: Changes in Size of Ancillary Service Pool

The size of the new reservoir volume dedicated to arbitrage energy production and ancillary services will affect the contribution generated from these income streams towards the net income of the project. In the base case scenario, the size of the ancillary service pool was adjusted as part of the manual optimization process. In Scenario 2, the allocation between arbitrage and ancillary services is explored by varying the amount of storage reserved for arbitrage energy generation from zero percent to 100 percent of the total volume of the new reservoir. This scenario helped inform the optimization effort on the baseline.

9.1.3.3 Scenario 3: Changes in Energy Prices (CO_2 Regulatory Costs vs No CO_2 Regulatory Costs)

Scenario 3 compares how income would change based on forecasted energy prices with CO_2 regulatory costs and energy prices without CO_2 costs. The Northwest Power and Conservation Council provided forecasted energy prices. Chapter 10 includes a further description of the prices. In general, energy prices with CO_2 regulatory costs are higher than those without. Costs are also less variable in most months, making arbitrage less attractive in these months.

9.1.3.4 Scenario 4: Changes in Ancillary Service Prices

Scenario 4 tests the sensitivity of income to changes in ancillary service prices. There is much uncertainty in forecasting ancillary prices. The operations model includes various options for price forecasts. This scenario tests potential income under each of the ancillary price forecast options. The ancillary service price options include the following:

- 2011 Prices, No Escalation – this option uses the CAISO 2011 ancillary service prices without any escalation. Prices would be the same for the entire 50-year period of analysis.
- 2011 Prices + 3% Escalation – this option assumes that 2011 prices would escalate each year by 3 percent through 2032, then would remain constant for the remainder of the 50-year period of analysis.
- 2011 Prices + Without CO_2 Prices Escalation – this option assumes that 2011 prices would escalate at a similar rate to the energy prices without CO_2. The escalation rate was determined based on the average hourly escalation rate of energy prices without CO_2 through 2021. From 2021 through 2032, an average annual rate for without CO_2 escalation was used and applied to 2011 CAISO prices. The prices were escalated through 2032, and then would remain constant for the remainder of the 50-year period of analysis.
- 2011 Prices + With CO_2 Prices Escalation – this option assumes that 2011 prices would escalate at a similar rate to the energy prices with CO_2. The escalation rate was determined based on the average hourly escalation rate of energy prices with CO_2 through 2021. From 2021 through 2032, an average annual rate for with CO_2 escalation was used

and applied to 2011 CAISO prices. The prices would be escalated through 2032, and then would remain constant for the remainder of the 50-year period of analysis.

9.1.3.5 Scenario 5: Climate Change

The objective of Scenario 5 is to assess the impact of climate change in the system's ability to respond to water needs for water and energy generation demands. Climate change would affect the timing and magnitude of runoff into the forebay reservoirs. In the context of the operations model, climate change will impact the water levels in the forebay reservoirs. Changing water levels could have similar effects to the pumped storage project as Scenario 1, where water levels could fall below minimum operating levels in the forebay reservoir or changing water levels could affect energy generation.

Results of the operational analysis under each scenario are presented below.

9.1.4 Model Output

The operations model provides a range of output in the form of hourly flows, calculated energy production and consumption, and income. Because the model uses an hourly time step and a week-long duration to make use of the available pricing data (historic hourly pricing data is specified as a "typical week" for a given month and year), energy and income totals discussed in this report are totaled over a week-long period. The results vary from month to month, based on changes in energy prices and hydrology (forebay reservoir water elevation). The weekly income results are converted to annual benefits in the benefit cost evaluation for the economic analysis.

9.2 Yellowtail Operations Analysis

This section presents the results of the base case and scenarios analysis for the Yellowtail 5A site. Section 9.1.3 describes the base case and scenarios.

9.2.1 Model Inputs

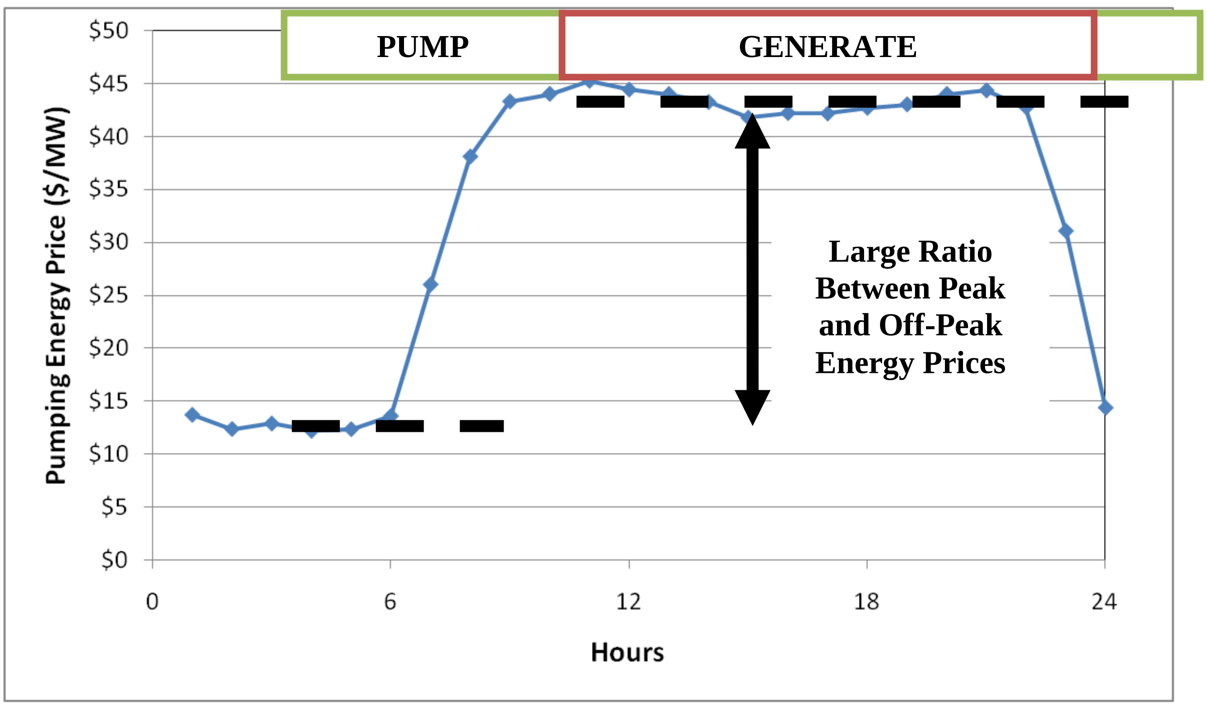
Table 9-2 shows the model inputs for facilities used in the Yellowtail model.

Table 9-2. Yellowtail Model Inputs

Model Parameter	Parameter Value Used in Baseline Yellowtail Simulation
New Reservoir Capacity	12,081 AF
Pump Flow (Max)	3,379 cfs
Pump Efficiency	0.902
Generating Flow (Max)	3,623 cfs
Turbine Capacity	415 MW
Min Allowable Forebay Elev	3,547 ft (Bottom of Active Conservation Pool)
Max Upper Water Elev	5,260 ft

The baseline operations model for Yellowtail was optimized to maximize net income from arbitrage and ancillary services[1]. The optimal operations schedule varied from month to month based on the "typical week" energy prices. Figure 9-5 below shows the typical pump and generation timing throughout a day in the context of an example of variable energy pricing. To maximize income from the production of arbitrage energy, the system must pump when energy prices are low (during off-peak hours) and generate electricity when energy is most costly (during peak hours). For a given generation capacity, the larger the difference, or ratio, between the peak and off-peak prices, the larger the net income produced by the pumped storage project. The off-peak vs. peak price differential will change throughout the year and for different power markets.

Figure 9-5. Typical Pump and Generation Timing



Since a pumped storage system is a net energy consumer, if the ratio between peak and off-peak pricing is too low, then the net benefit from arbitrage energy production could be minimal or even negative. In these cases, the reservoir volume reserved for ancillary services is maximized to provide for the highest potential net income. To quantify the ratio between peak and off-peak pricing for the Yellowtail baseline simulation, the average ratio between the 6 highest hourly prices each weekday and 6 lowest hourly prices each weekday for each month in 2032 was computed. This assumes that the pumped storage system would pump and generate for a minimum of 6 hours each day. The ratio between the 6 highest and 6 lowest hourly prices for each day of the "typical week" of price data is averaged to arrive at a single number for each month.

[1] Operations were not mathematically optimized, but rather optimized using educated "trial and error."

Montana market prices are used in the Yellowtail model. The resulting ratios are summarized in Table 9-3 below. The month of June had a much larger difference in the high and low energy prices on Monday and Thursday relative to other months; therefore, the ratio is much higher.

Table 9-3. Peak Energy Price Ratio for Yellowtail Baseline Simulation

Month of Simulation	Peak Energy Price Ratio [Peak/Off-Peak]	Percentage of Reservoir Storage Dedicated to Arbitrage
January	1.79	0%
February	1.84	0%
March	2.15	50%
April	2.43	50%
May	3.65	50%
June	9.44	90%
July	1.94	0%
August	2.69	90%
September	1.34	0%
October	1.18	0%
November	1.44	0%
December	1.98	0%

Based on the manual optimization of operation schedules, it was determined that arbitrage energy generation would result in a positive income in March, April, May, June, and August of the simulation. Comparing to the peak price ratio information provided above, the economic feasibility of arbitrage power generation correlated to a price ratio of approximately 2.0. For the months where the peak price ratio was greater than 2.0, the income from arbitrage power generation were large enough (compared to the potential income from ancillary services) to support dedicating a large amount of storage to arbitrage generation. The optimized pumping/generation schedule for these months is summarized in Table 9-4. The hourly operations vary slightly across months with arbitrage depending on the hourly prices.

Table 9-4. Yellowtail Optimized Pump/Generation Schedule for Arbitrage

Time of Day	Operation
Hours 1 - 9	PUMP
Hours 10 - 21	GENERATE
Hours 22 - 24	PUMP

In all other months, the reservoir volume dedicated to ancillary services was set to 100% (no arbitrage energy generation). The size of each ancillary service pool was also manually optimized to increase potential income. Table 9-5 shows the proportions of each ancillary service relative to the ancillary service pool for each month. As described above, these percentages were selected based on the stepwise manual optimization process. In general, spinning and regulation up provide the most income because the supplier receives both the price for the ancillary service and the energy price for generation. For regulation down, the supplier only receives the ancillary service price. Non-spinning is set to a low percentage because of the relative low price for the service and the low probability that it is called upon. Note in July and August, the ancillary service pool is only set to 10% of the total pool volume and most of the project is operated for arbitrage (Table 9-3).

Table 9-5. Ancillary Service Pool Sizes for Yellowtail Baseline Simulation

Month of Simulation	Spinning Reserves	Non-Spinning Reserves	Regulation Up	Regulation Down
January	20%	10%	60%	10%
February	25%	5%	60%	10%
March	25%	5%	60%	10%
April	25%	5%	60%	10%
May	25%	5%	60%	10%
June	25%	0%	60%	15%
July	25%	5%	60%	10%
August	25%	25%	25%	25%
September	25%	5%	60%	10%
October	25%	5%	60%	10%
November	25%	5%	60%	10%
December	25%	5%	60%	10%

9.2.2 Base Case Results – Maximize Income

Energy generated for both arbitrage and ancillary services varies based on the proposed operation (timing and duration of pump and turbine operation) of the pumped storage project. For months where the project is set to only provide for ancillary services, the power generated/absorbed and associated income would come from these ancillary services. Figure 9-6 is stacked line graph that shows the generating power to support ancillary services for a typical week in the month of January. In January, all of the potential power generation is dedicated to ancillary services. The units would operate at full generating capacity to provide regulation up, spinning, and non-spinning services and to empty the regulation down pool. The maximum energy generation is approximately 1,660 MW. This graph corresponds to the generating operating range described in Chapter 6.

Figure 9-6. Generation Pattern in January at Yellowtail

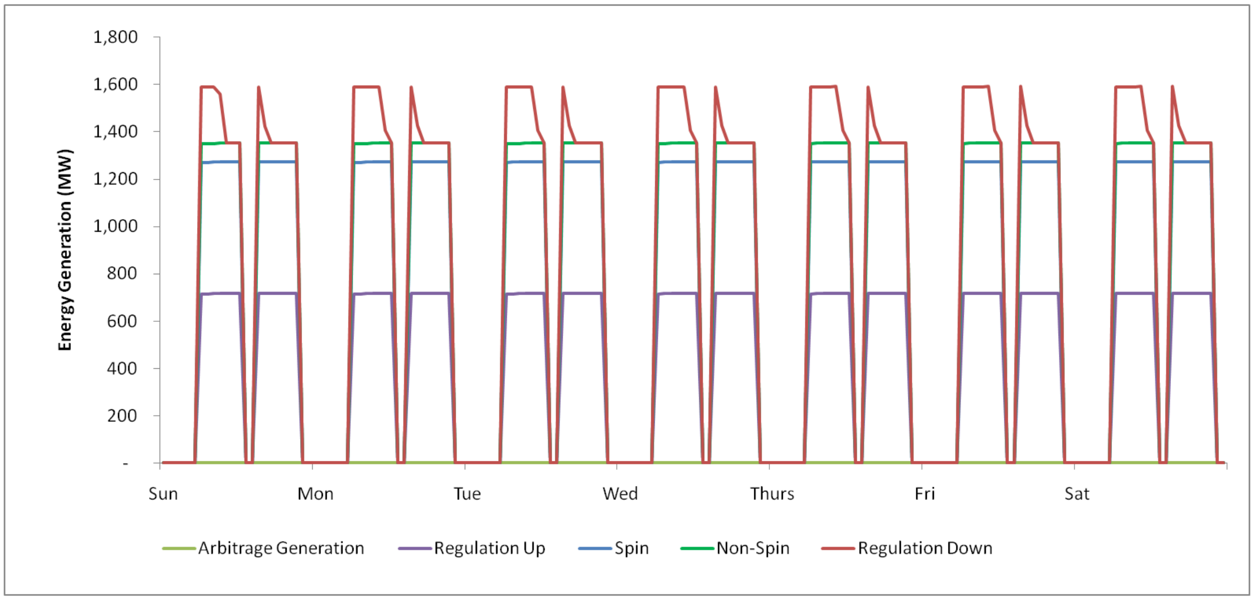
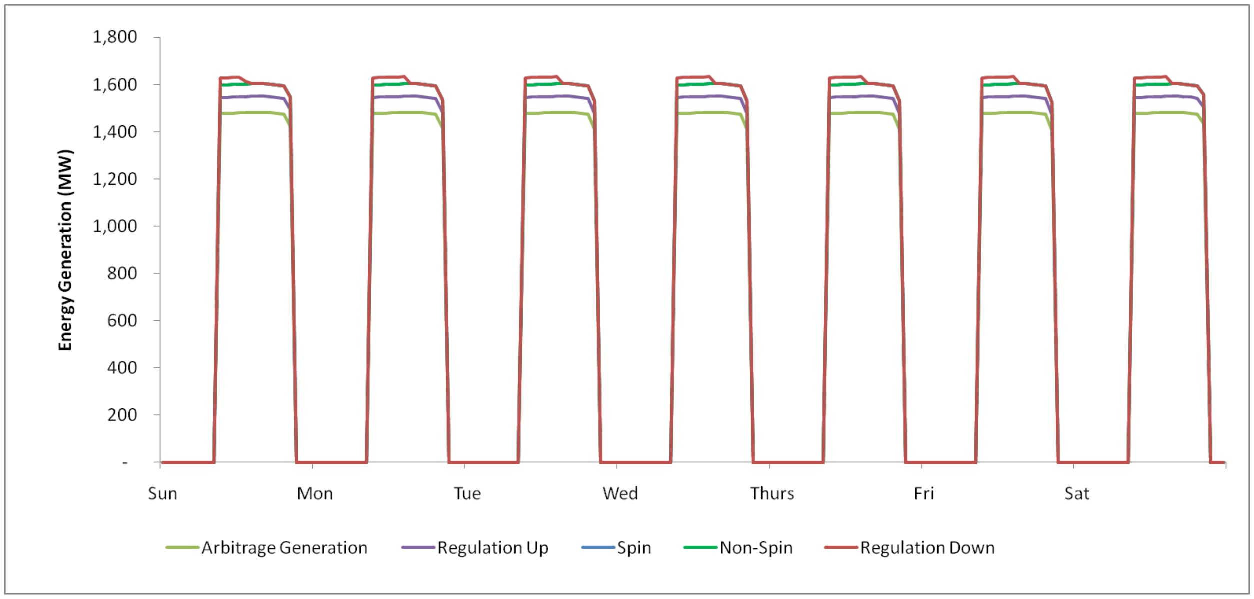


Figure 9-7 shows generating patterns for a typical week in the month of June for the baseline Yellowtail simulation. In June, 90% of the reservoirs storage is dedicated to arbitrage, with a peak of almost 1,500 MW of power produced for arbitrage and minimal power available to meet ancillary benefits.

Figure 9-7. Generation Pattern in June at Yellowtail



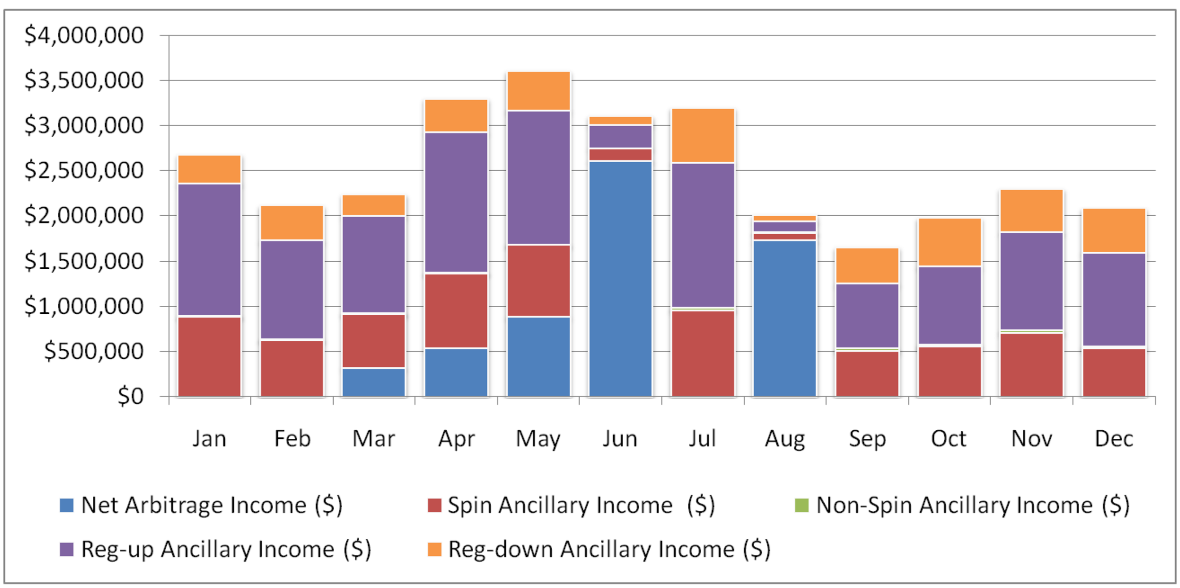
The average weekly income for each month of the optimized baseline Yellowtail simulation is summarized in Figure 9-8. The income mix varies from month to month based on specified arbitrage/ancillary service operations and prices. In most summer months, arbitrage is used to generate some income.

The exception to this convention is the optimized results for July, which, based on the price ratio analysis above, was not conducive to arbitrage power generation. For this reason, the full storage of the reservoir was reserved for ancillary services in the month of July in the baseline Yellowtail simulation. During the winter months, all of the income is sourced from ancillary services.

The breakdown between ancillary services shows the majority of weekly income is sourced from potential regulation up and spinning reserves. Regulation down also provides a substantial portion of the total weekly income. The regulation down programming assumes that the supplier is paid for the service and does not need to purchase the energy. The income is solely due to the relatively high value of regulation down services. Regulation down programming could be changed to allow for the supplier to also be paid for the foregone energy when the service is provided, which would provide additional income from energy.

Only a small amount of income is sourced from non-spinning reserve services. Non-spinning reserves are the lowest quality ancillary service and provide the lowest income of the ancillary services. These reserves are primarily for power system contingencies and there is generally a low probability of them being called upon. In this simulation, the non-spin pool is set to 5% of the total ancillary service pool volume. There is some economic benefit to providing the service because the supplier gets paid for simply providing it without having to operate the system, unless called upon. Some level of non-spinning reserves may be needed to satisfy reliability requirements.

Figure 9-8. Average Weekly Income for the Optimized Baseline Yellowtail Simulation



9.2.3 Scenario 1 Results

Scenario 1 compares the effects of the Yellowtail project on Bighorn Lake water elevations during dry and wet hydrologic conditions. Based on historic hydrologic data, the year 2002 was used to represent dry year conditions and the year 1999 was used to represent wet year conditions. In general, reducing water elevations or storage during dry years could affect water supplies available to meet water and power demands. Figure 9-9 shows Bighorn Lake elevations with the Yellowtail project under dry and wet year conditions, relative to water elevations without the project. The figure shows changes in elevations during a typical week in August, when forebay elevations are generally low after summer deliveries. The forebay elevation would change about 2 feet with the project under dry year conditions, but would still remain well within the active storage pool. Under wet conditions, the forebay elevation would change about 1 foot with the project.

The storage capacity of the upper reservoir was designed to be operated within the active conservation pool of Bighorn Lake. These scenario results support this and there would be no expected water supply impacts at Bighorn Lake under varying hydrologic conditions with the pumped storage project.

Figure 9-9. Bighorn Lake Elevation During Wet and Dry Hydrologic Conditions With and Without the Project

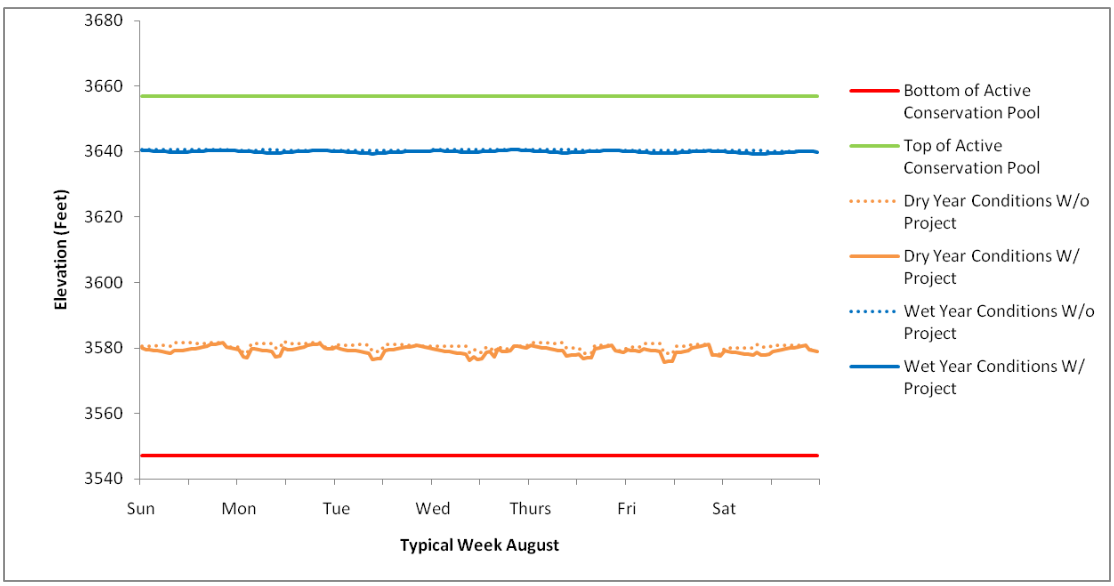
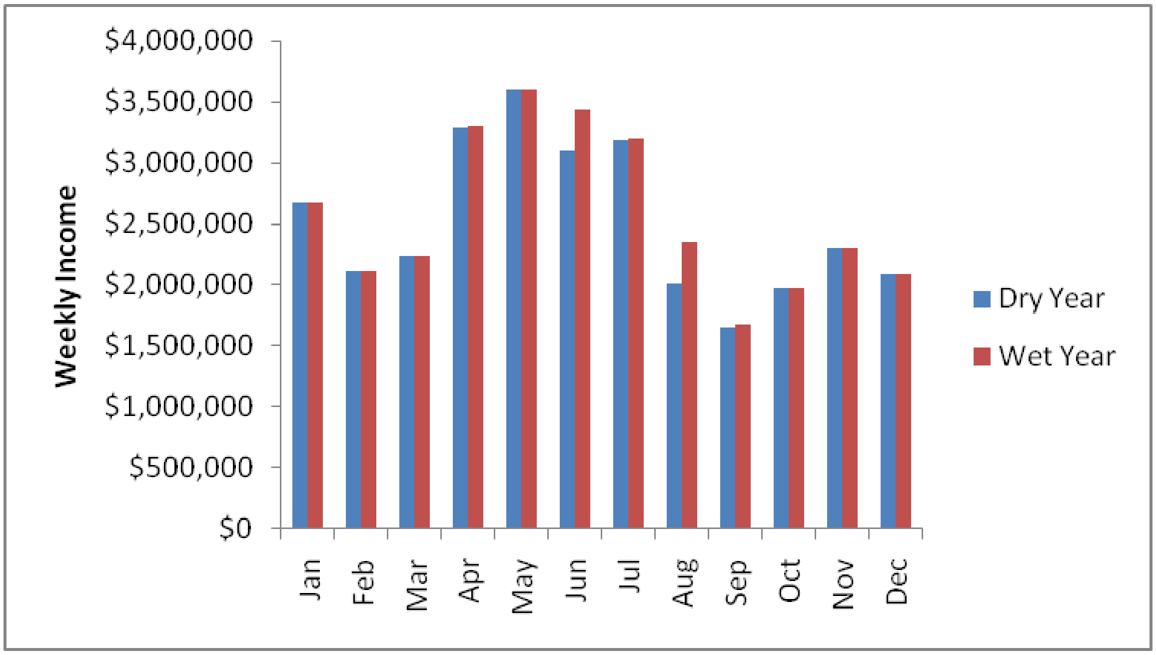


Figure 9-10 shows average weekly income each month over dry year and wet year conditions, including both arbitrage and ancillary services income. Income would be very similar between the year types. In general, in dry years, water levels are lower, which results in an increased difference in elevation between the two reservoirs. With more head, some additional energy would be generated during dry years than wet years. However, in some months of a dry year, the increased head can also become a limiting factor in the volume pumped.

Therefore, the upper reservoir cannot fill and generation potential decreases, which would decrease income in those months relative to wet years (i.e., June and August in Figure 9-10).

Figure 9-10. Yellowtail Project Average Weekly Income during Wet and Dry Years



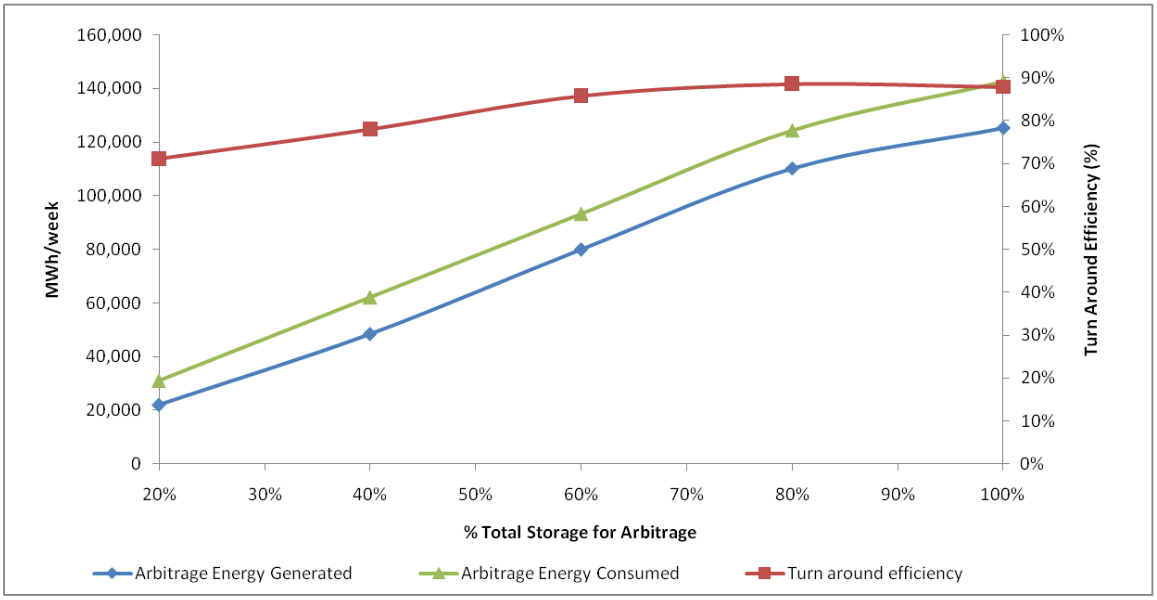
In summary, Scenario 1 results show that the Yellowtail project would not affect water supplies in Bighorn Lake available to meet downstream water and power demands during wet or dry hydrologic conditions. Project income and energy generation for the pump storage project would also not be substantially different in varying hydrologic conditions.

9.2.4 Scenario 2 Results

Scenario 2 evaluates how income changes relative to changes in the volume of the energy arbitrage pool. This scenario mostly helped to inform the optimization process. A large energy arbitrage pool means that more of the reservoir storage is used for energy arbitrage with a proportional reduction in storage available for ancillary services. Figure 9-11 shows average weekly energy generated, energy consumed, and turn around efficiency under various pool volumes in June. In general, June is one of the months when the variation in peak and off-peak energy prices make energy arbitrage a more profitable operation relative to other months. Energy arbitrage is always a net consumer of energy, as shown in the figure. The variation in energy prices allows for positive income.

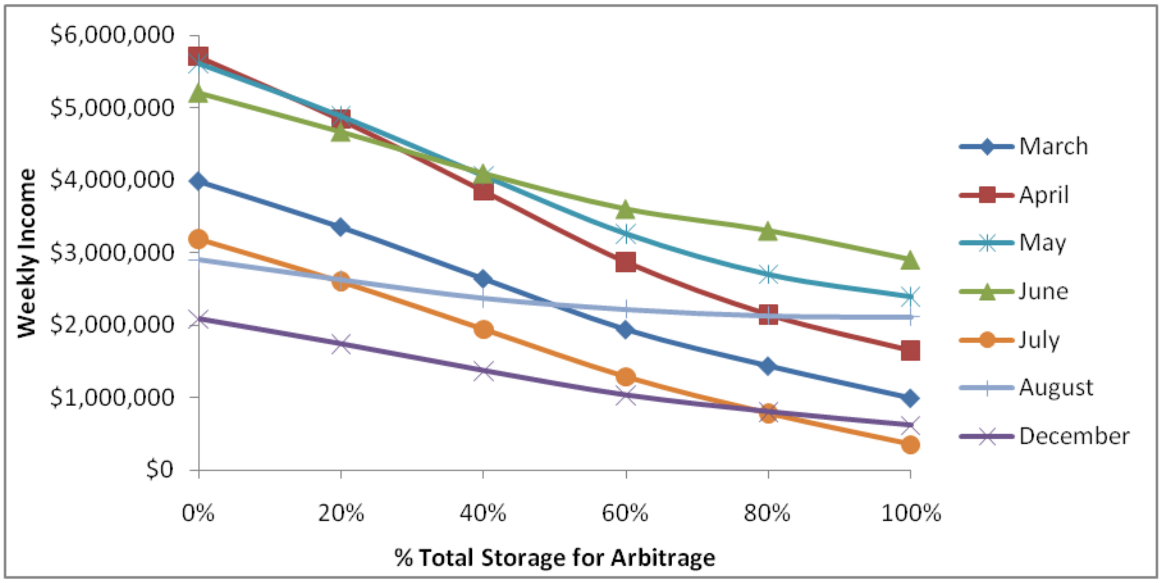
In general, the turn-around efficiency calculated by the model (about 71% to 90%) is slightly higher than the expected range, which is about 78-82%. This is likely due to the assumed high pump and generating efficiencies of the variable speed units.

Figure 9-11. Weekly Energy Generated and Consumed at Yellowtail in June



Energy prices and price schedules vary across months; therefore, it is beneficial to vary the size of the energy arbitrage pool each month. Figure 9-12 shows total average weekly income, from both energy arbitrage and ancillary services, under various energy arbitrage pool volumes and different months, for illustrative purposes. The figure shows the spring and summer months, when the base case scenario operations include energy arbitrage and also December, when the model does not include any arbitrage. The trend in the line for December would be similar to other winter months. See Table 9-4 for arbitrage pool proportions under the base case scenario. Ancillary services would provide all the income when the arbitrage pool is set to zero percent.

Figure 9-12. Average Weekly Income from Arbitrage at Yellowtail



Having a positive net income from energy arbitrage is largely dependent on energy prices because energy arbitrage is a net consumer of energy. More income is generated under arbitrage if there is a greater difference in peak and off peak energy prices. During months with relatively flat energy prices, typically the winter months, energy arbitrage would not provide substantial income and operations should focus on providing ancillary services to maximize income. Figure 9-12 shows that high arbitrage percentages do not maximize income. The baseline scenario, however, incorporated arbitrage in most spring and summer months (March, April, May, June and August) because it was profitable based on the ratio of high and low energy prices. These months included arbitrage because it is likely that local utilities would need additional energy in the future to meet peaking demands. Additionally, having some level of pumping or generating can help the system respond instantaneously for regulation services.

9.2.5 Scenario 3 Results

Scenario 3 compares how income would change based on forecasted energy prices with CO_2 regulatory costs and energy prices without CO_2 costs. The CO_2 regulatory cost represents additional costs to comply with future greenhouse gas emission constraints; therefore, the set of energy prices with the CO_2 cost is higher than the prices without it.

Figures 9-13 and 9-14 show typical week energy prices for both price options in August and December, respectively. August and December are shown to indicate the relative differences in summer and winter months. Prices are less variable during December and most winter months relative to August and other summer months. The difference between price with CO_2 regulatory costs and without CO_2 costs is also greater in December relative to August. Negative prices can occur because of increased renewable energy production credits, mostly wind, or the presence of transmission congestion.

Figure 9-13. Typical Week Energy Prices at Yellowtail in August with and without CO_2 Regulatory Costs

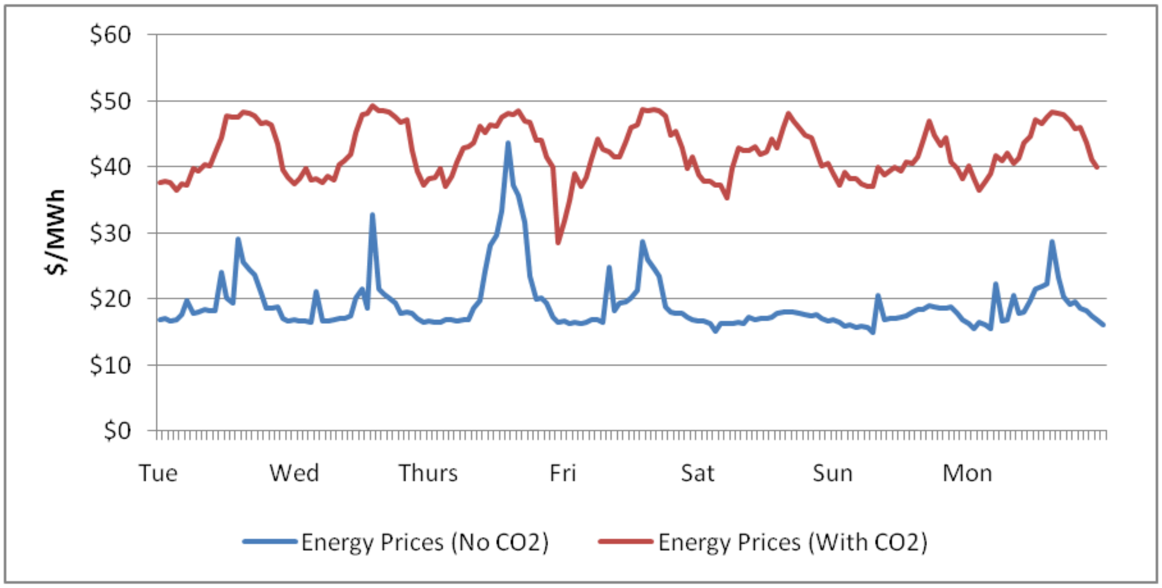
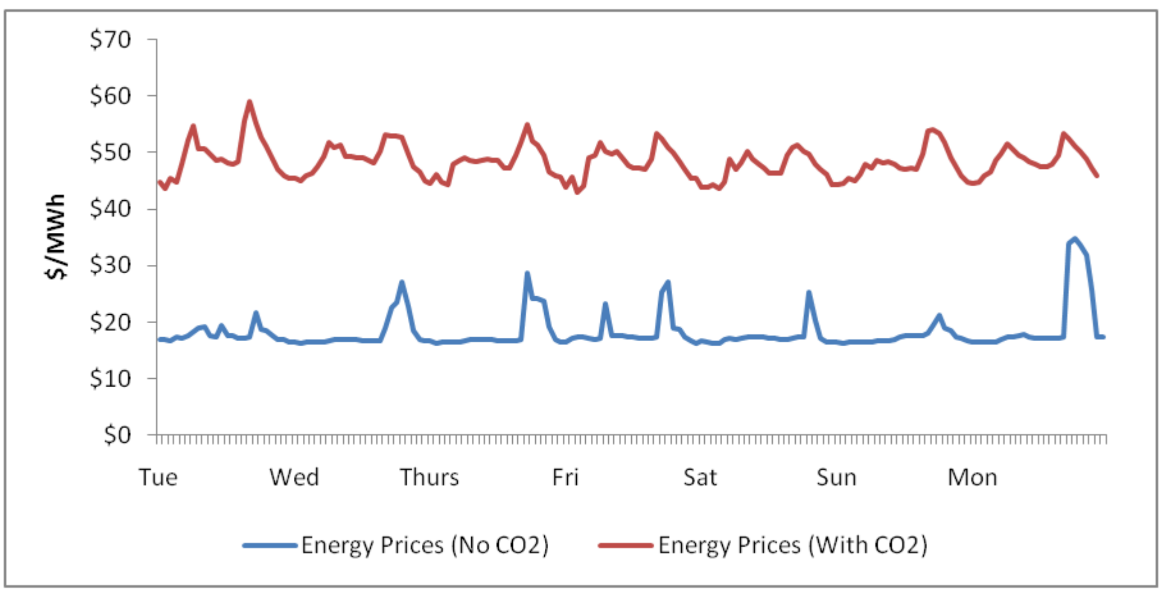


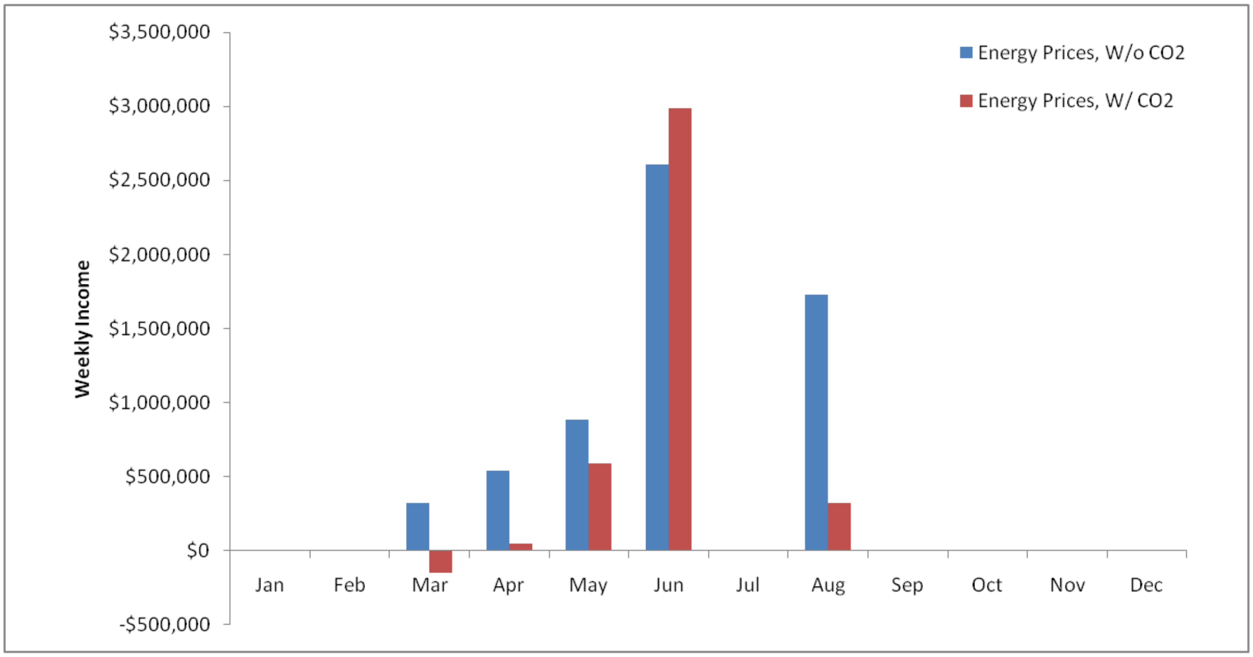
Figure 9-14. Typical Week Energy Prices at Yellowtail in December with and without CO2 Regulatory Costs



Because of the difference in monthly energy prices, project operations assuming the price without CO_2 would vary from operations assuming the prices with CO_2 in order to maximize income. The base case scenario (described above) includes operations to maximize income assuming energy prices without CO_2

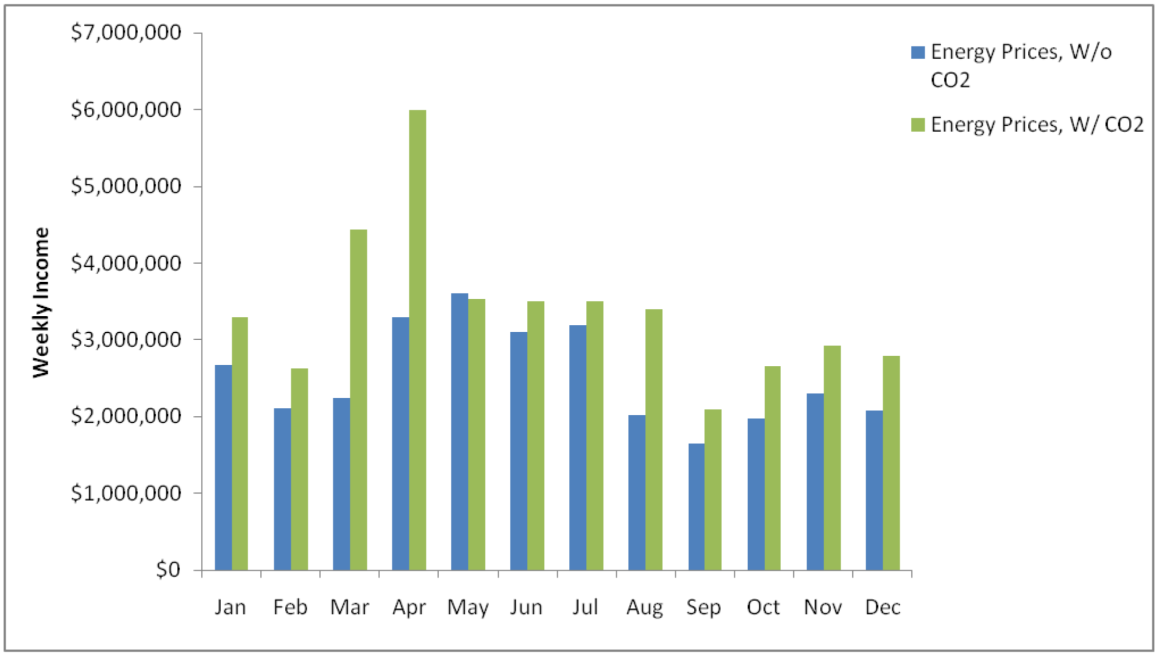
prices. Figure 9-15 shows only arbitrage income (not including ancillary services income) of the base case scenario using prices with CO_2 compared to prices without CO_2. It can be seen that project operations under the base case simulation using prices with CO_2 do not maximize income during most months. Therefore, operations for arbitrage or ancillary services were changed during these months to increase income.

Figure 9-15. Arbitrage Average Weekly Income at Yellowtail with and without CO_2 Regulatory Costs



Using energy prices with CO_2, weekly income would be maximized if the reservoir is operated only for ancillary services in all months but May and June. The manual optimization sets the arbitrage reservoir pool to 50% in May and 90% in June of total pool volume. Figure 9-16 shows total (energy arbitrage and ancillary services) average weekly income under operation scenarios that maximize income using both energy prices with and without CO_2. The income generated based on energy prices with CO_2 would be more because the project is being operated more for ancillary services under the prices with CO_2 optimized simulation (which have a higher value than arbitrage) and the energy prices with CO_2 are higher than the prices without CO_2, which is accounted for when ancillary services are deployed. April and March are particulary different because under the prices with CO_2 simulation, the project is fully operated for ancillary services rather than some percentage of arbitrage.

Figure 9-16. Total Average Weekly Income at Yellowtail with and without CO_2 Regulatory Costs



9.2.6 Scenario 4 Results

Scenario 4 tests the sensitivity of income to changes in ancillary service prices. The base case scenario is run with the four different price options. Ancillary service prices are dependent on multiple market factors, such as gas prices, available hydropower, and wind energy sources, which can be extremely variable. Unlike energy prices, ancillary service price forecasts are not readily available. The operations model includes various ancillary service price forecasts to provide a range of values for future prices. It is unknown how prices will change in the future, but in general, most experts believe that prices will increase because of increased production of renewable energy resources.

Figures 9-17 through 9-20 show average weekly income by month in 2032 for the four ancillary services under each escalation option. The escalation options are described in Section 9.1.5. The escalation options are estimated based on the same proportions of arbitrage and ancillary services in the baseline. June and August would have lower ancillary service income because 90 percent of the new reservoir pool is dedicated to energy arbitrage. Under all price options, regulation up and regulation down services would provide the most income because they are considered the highest quality services. Income is highest assuming ancillary service price escalation similar to the energy prices with CO_2 escalation rates.

Figure 9-17. Average Weekly Income from Spin Ancillary Services at Yellowtail

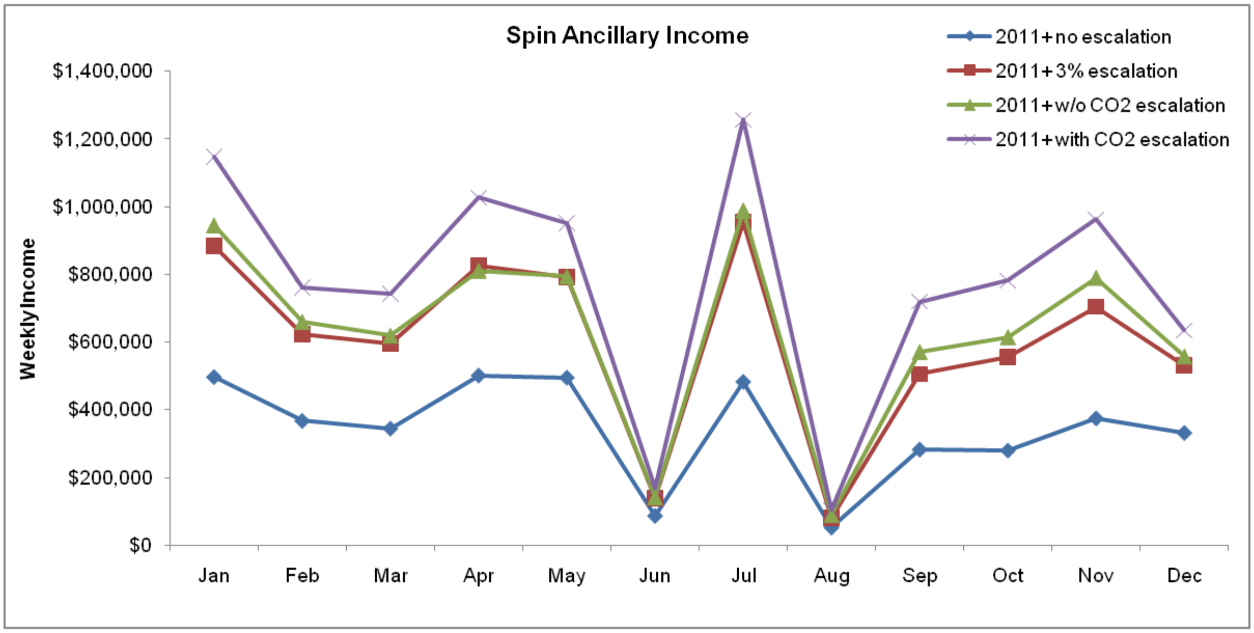


Figure 9-18. Average Weekly Income from Non-Spin Ancillary Services at Yellowtail

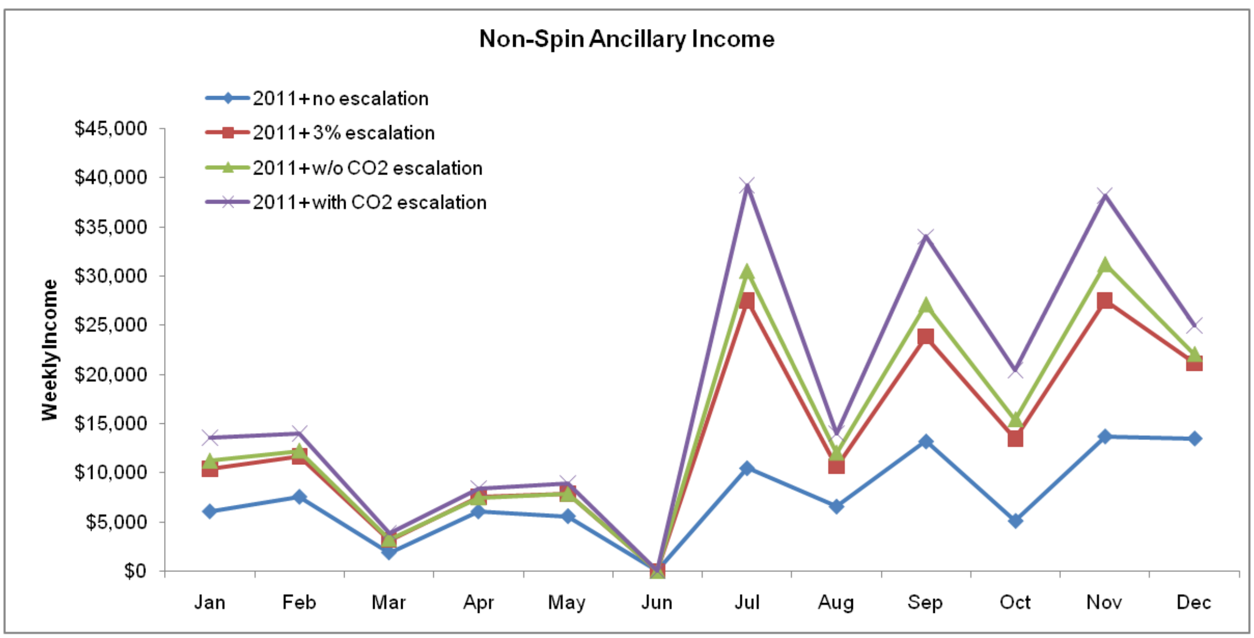


Figure 9-19. Average Weekly Income from Regulation Up Ancillary Services at Yellowtail

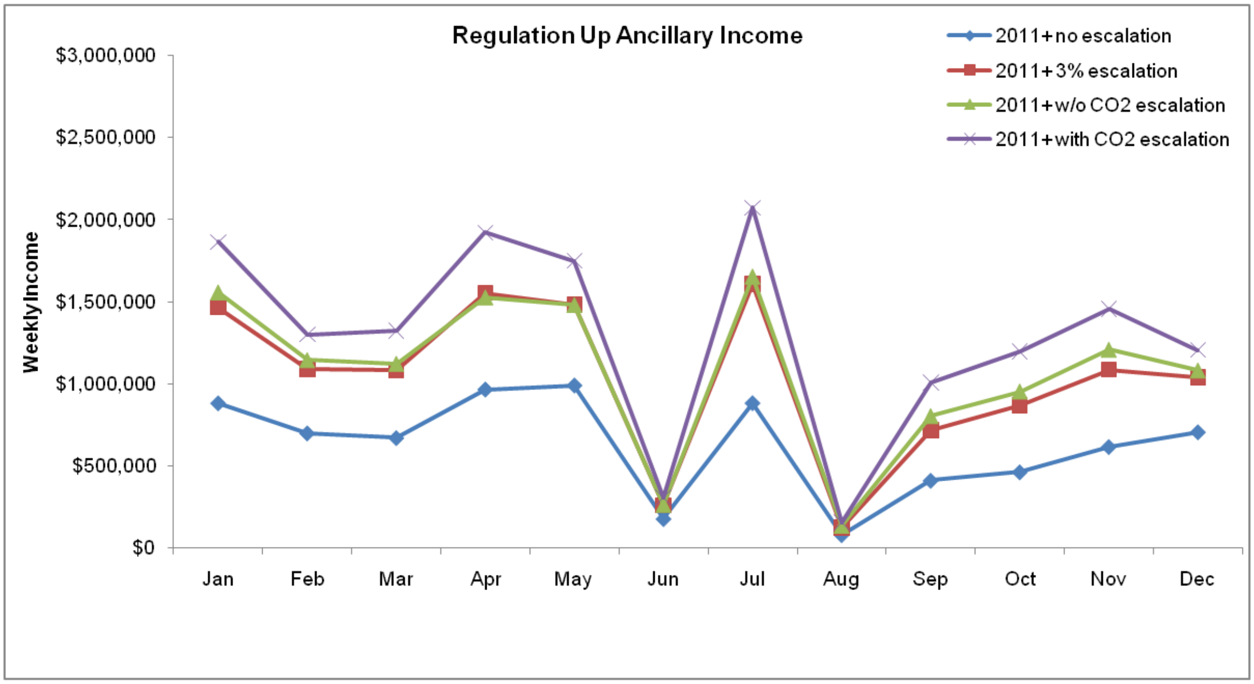


Figure 9-20. Average Weekly Income from Regulation Down Ancillary Services at Yellowtail

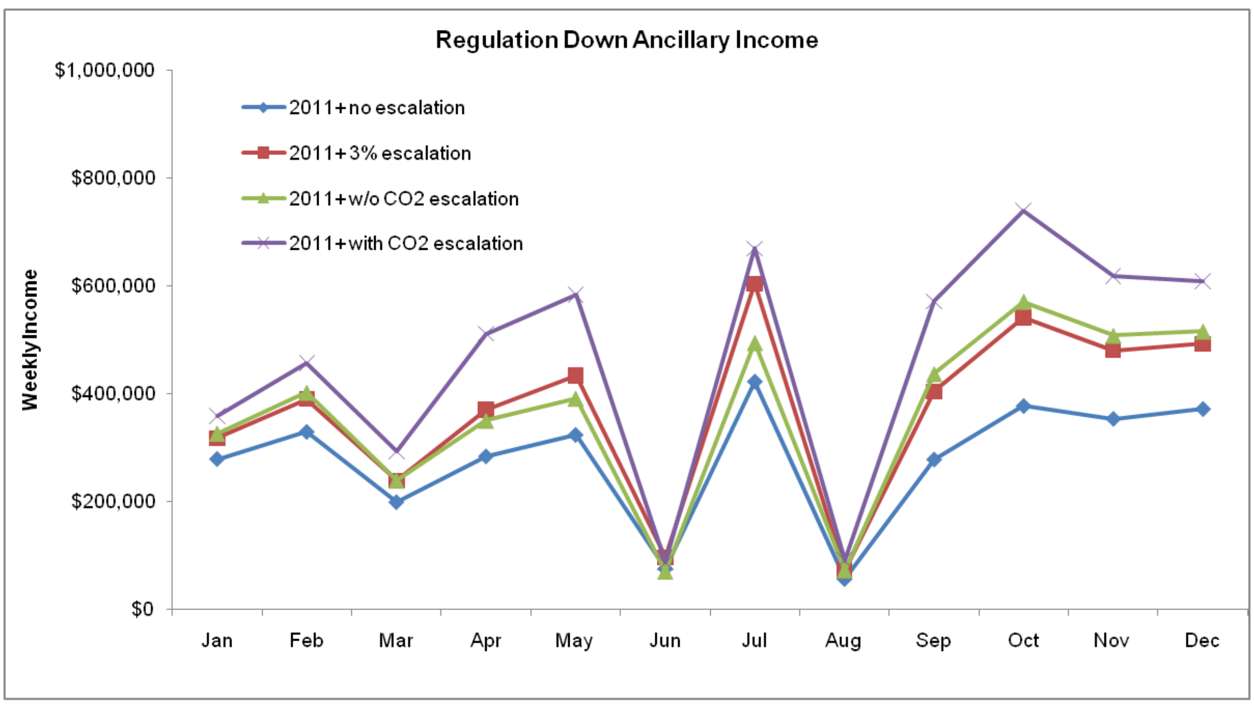
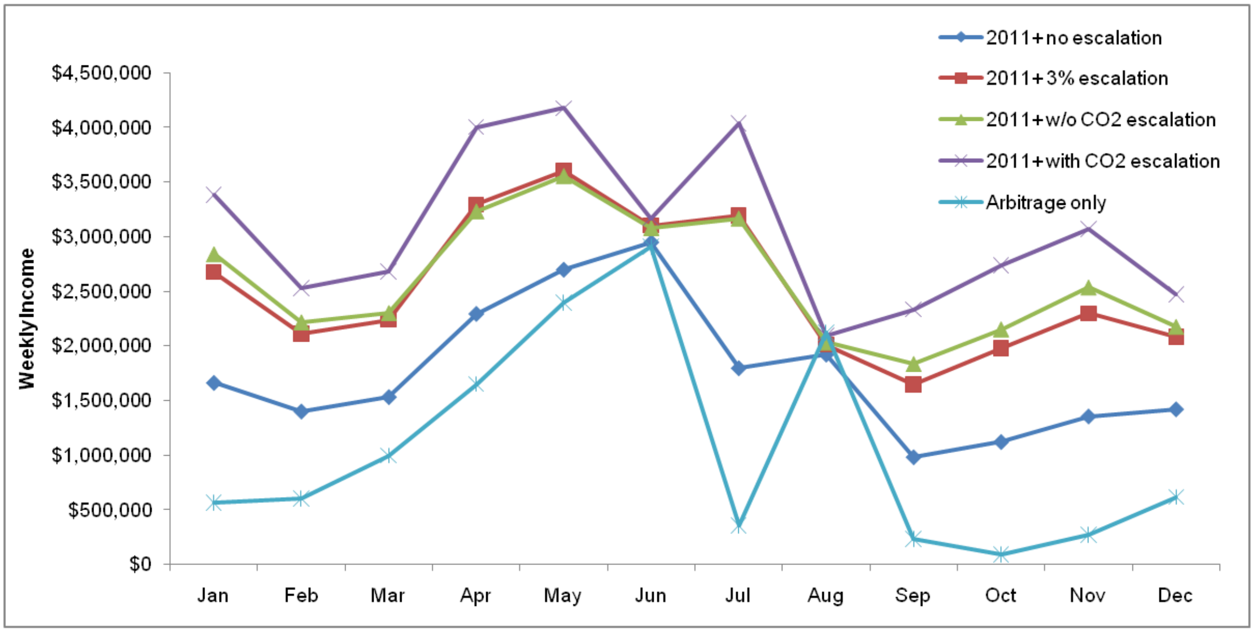


Figure 9-21 shows average weekly total income, which includes energy arbitrage and ancillary services, under the various ancillary service price forecasts. During the winter months, the project is operated only for ancillary services. This scenario shows that increases in future ancillary service prices relative to no escalation would substantially improve the project's total income. The weekly income for arbitrage only is also shown on Figure 9-21 and highlights how ancillary services add to the total income of the project.

Figure 9-21. Average Weekly Income with Varying Escalation at Yellowtail



9.2.7 Scenario 5 Results

The objective of Scenario 5 is to assess the impact of climate change in the system's ability to respond to water needs for water and energy generation demands. The most critical measure of impact is the frequency of future use restrictions due to decreased water levels. If precipitation changes due to climate change are significant to the point that water levels in Bighorn Lake would drop under the bottom of the active conservation pool, future pumped storage operations would be compromised or restricted. Thus the climate change analysis focuses on determining the likelihood of significant reductions in precipitation in Bighorn Lake's catchment area and runoff into the lake.

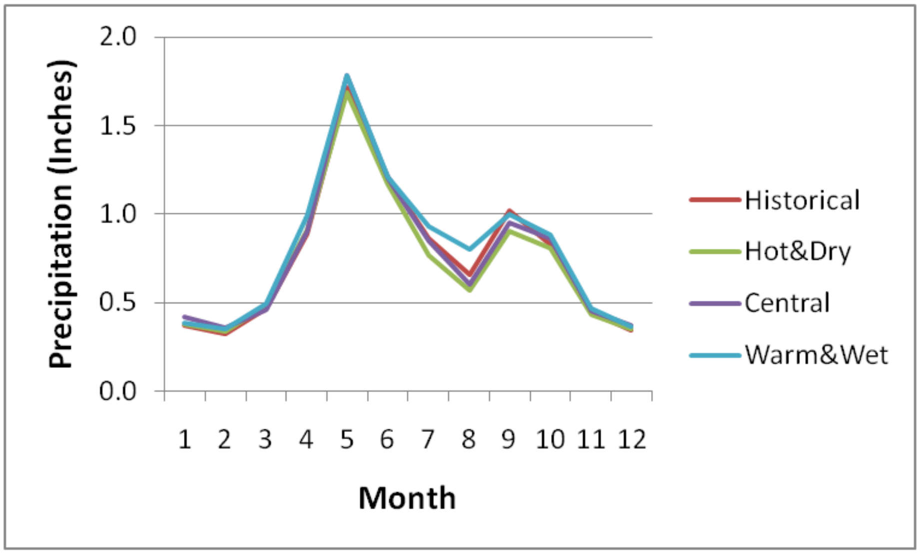
Assuming the same operational objectives (driving operational flows), the most significant impacts related to water level in Bighorn Lake are evaporation and natural inflows. Evaporation has not been included in the operations model and it is also excluded from the analysis in the climate change scenario, for consistency.

For inflows into the lake, the overall approach consisted of obtaining projections of precipitation in the area under climate change conditions and indications of runoff changes as a result. The main two sources of information used in the analysis were the SECURE Water report (SECURE Water Act Section 9503(c) – Reclamation Climate Change and Water 2011) and the databases available in the Climate Resiliency Evaluation and Awareness Tool (CREAT) developed by U.S. Environmental Protection Agency (EPA). The CREAT (version 2.0) database includes multiple climate model projections providing a distribution of possible future conditions for each specific locations.

Bighorn Lake is part of the Missouri basin, which, while being a very extensive basin, is generally projected to experience increases in precipitation (Reclamation 2011). This includes the general area of the Bighorn Lake catchment that generates runoff to the lake. The closest sub basin reported in the SECURE Report (Reclamation 2011) is the Milk River basin at Nashua Montana, where the mean annual runoff is projected to increase over 8 percent by the 2050s. The mean December-March runoff and the mean April-July runoff are also projected to increase.

To provide additional geographic specificity, the CREAT Tool was used to obtain precipitation data for the Bighorn Lake catchment area. Three groups of predictions were used from models that tend to predict “Hot and Dry” years, “Central” models, and models predicting “Warm and Wet” years. Of the three types of predictions, the Hot and Dry prediction is the only one that predicts reduction in precipitation. It should be mentioned that there are more GCMs that predict a Central tendency and a Warm and Wet tendency than a Hot and Dry tendency for this region, so there is higher degree of agreement that this region would see precipitation increases or no change. A summary of precipitation by month for each of these three types of predictions for the 2030s was compared to historical data, with results presented in Figure 9-22, which shows only a minimal change in precipitation in the Bighorn Lake area. The annual precipitation historically is 9.12 inches while precipitation for the three types of climate change projections ranges from 8.8 to 9.65 inches per year.

Figure 9-22. Monthly Precipitation (inches) Comparison for Historical Record vs. Climate Change Projections for the Bighorn Lake Area



Given the minimal projected impact of climate change in precipitation and runoff for the Bighorn Lake area, climate change conditions (as predicted by the models used in this analysis) would most likely not have an impact on the pumped storage operations at the Yellowtail site.

9.2.8 Ancillary Service Modeling Considerations

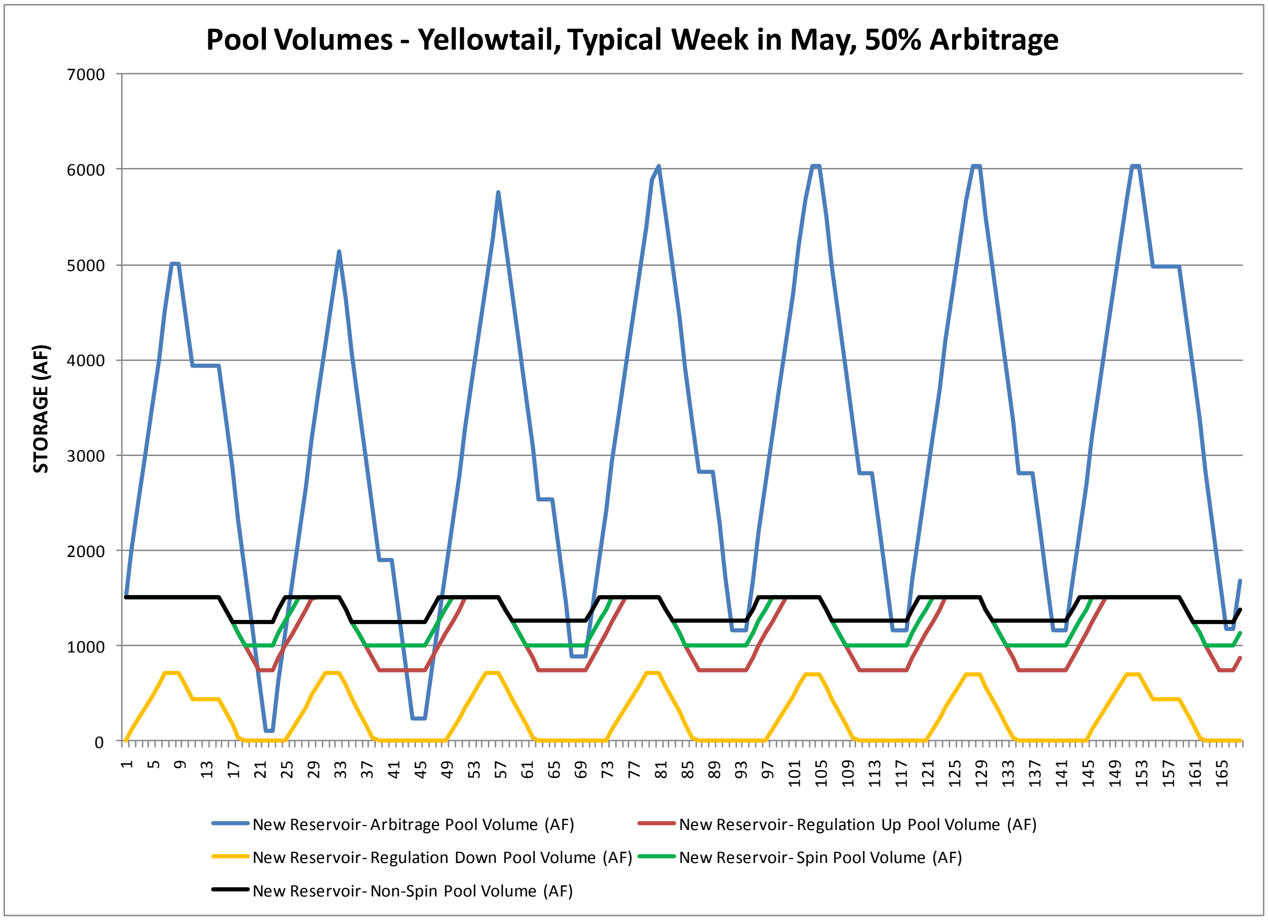
For deployment of ancillary services, income would be received from both the sale of ancillary services and the additional energy generated as a result of deployment. It should be noted that anytime water is released for regulation up, spinning reserves, and non-spinning reserves, it must be pumped back to the upper reservoir, which would incur additional pumping costs. For regulation down, it is assumed that the income would only be from the purchase of ancillary services. This programming could change to allow for income to be generated from foregone energy generation as a result of providing regulation down.

As discussed above, the model is set up as a simulation model with a stepwise manual optimization for revenues. There are many parameters that can vary to change the income or revenue generated. These include the hourly operations schedule, the ancillary/arbitrage pool volumes, the individual ancillary service pool volumes, and the capacity dedicated to each ancillary service. The baseline scenario is developed to have a maximum income, realizing that there may be some room for improvement with further changes in the parameters. It is not expected additional changes would result in a substantial change in the results. Additional income may be generated from ancillary services with a slight change in the operations model programming. Each ancillary service can accrue income in two ways, both by being available when the system is operating in either pump or generating mode and by actually being used or deployed. For regulation-up, the analysis accrues income whenever the system is generating, using the cost structure associated with the availability of this ancillary service. Additional income is generated if a "call" or demand is placed on the regulation-up pool and water from that pool is actually used to generate power. The amount of regulation-up service deployed when it is called upon is dependent on the capacity available multiplied by the probability that regulation is needed at any one time step.

Likewise, for regulation-down, the analysis accrues income whenever the system is pumping, using the cost structure associated with the availability of this service. The amount of regulation-down service deployed when it is called upon is dependent on the capacity available multiplied by the probability that regulation is needed at any one time step.

The operations model currently provides either generation or pumping capability, based on the operations schedule specified by the user. Examination of the figure below indicates that the regulation up and regulation down pools often fill and empty synchronously. The use of variable speed pump/turbine units allows for the capability to serve both regulation-up and regulation-down simultaneously, in addition to spinning and non-spinning reserves. When the system, or a single pump/turbine unit, is pumping, down regulation is provided by changing its operations to increase pumping. A pump unit which is already pumping can also provide up regulation by moving into the "off" mode, or adjusting its pumping level downward. Similarly, when the system, or a single pump/turbine unit, is generating, up regulation is provided by changing its operations to increase generation. A unit which is already generating can also provide regulation down by moving into the "off" mode, or adjusting its generation level downward. As the system is configured, there may be missed opportunities to generate or absorb energy and increase income.

Figure 9-23. Example of Regulation Pools Filling and Emptying Synchronously



9.3 Seminoe Operations Analysis

This study considers three pumped storage configurations at the Seminoe site – 5A2, 5A3, and 5C. For the operations analysis, the base case scenario is run for all three configurations. Scenarios 1 through 5 are only run for Site 5A3, which is the site with the highest income. It also has the lowest estimated cost per MW, as shown in Chapter 8.

9.3.1 Seminoe Model Inputs

Table 9-6 shows the model inputs for facilities used in the Seminoe model.

Table 9-6. Seminoe Model Inputs

Model Parameter	Parameter Value Used in Baseline Seminoe 5A3 Simulation
New Reservoir Capacity	12,277 AF
Pump Flow (Max)	3,441 cfs
Pump Efficiency	0.902
Generating Flow (Max)	3,378 cfs
Turbine Capacity	276 MW
Min Allowable Forebay Elev	6,239 ft (Bottom of Active Conservation Pool)
Max Upper Water Elev	7,440 ft

The peak price ratio for the baseline Seminoe simulation is summarized in Table 9-7. Overall, the peak price ratios for Seminoe are lower than the baseline Yellowtail simulation.

Table 9-7. Peak Energy Price Ratio for Seminoe Baseline Simulation

Month of Simulation	Peak Energy Price Ratio [Peak/Off-Peak]	Percentage of Reservoir Storage Dedicated to Arbitrage
January	1.16	0%
February	1.18	0%
March	1.89	0%
April	2.23	50%
May	2.74	50%
June	2.93	50%
July	1.07	0%
August	1.12	0%
September	1.14	0%
October	1.07	0%
November	1.11	0%
December	1.10	0%

Using the peak price ratio guidance of 2.0 and additional manual optimization, it was determined that arbitrage energy generation would be feasible in April, May, and June of the simulation. The optimized pumping schedule for these months is summarized in Table 9-8. This schedule, when compared to the Yellowtail optimized schedule has one less hour of generation at night because energy prices are lower at that time.

Table 9-8. Seminoe Optimized Pump/Generation Schedule for Arbitrage

Time of Day	Operation
Hours 1 – 7	PUMP
Hours 8 – 20	GENERATE
Hours 21 – 24	PUMP

In all other months, the reservoir volume dedicated to ancillary services was set to 100% (no arbitrage energy generation). The size of each ancillary service pool was also manually optimized to increase potential income. Table 9-9 shows the proportions of each ancillary service relative to the ancillary service pool for each month.

Table 9-9. Ancillary Service Pool Sizes for Seminoe Baseline Simulation

Month of Simulation	Spinning Reserves	Non-Spinning Reserves	Regulation Up	Regulation Down
January	30%	0%	60%	10%
February	25%	5%	60%	10%
March	30%	0%	60%	10%
April	25%	5%	60%	10%
May	25%	5%	60%	10%
June	25%	5%	60%	10%
July	25%	5%	60%	10%
August	25%	5%	60%	10%
September	25%	25%	25%	25%
October	25%	25%	25%	25%
November	25%	25%	25%	25%
December	25%	25%	25%	25%

9.3.2 Seminoe Base Case Results – Maximize Income

Figure 9-24 is a stacked line graph that shows the total generation for a typical week in the month of January in the baseline Seminoe 5A3 simulation. In January, all of the potential power generation/absorption is dedicated to ancillary services. The potential energy for regulation up, spinning, and non-spinning services is approximately 1,100 MW when the pumped storage project is generating. The system is set up to provide 60% of the ancillary service pool for regulation up, 30% for spinning reserves, and 10% for regulation down. There would be no non-spinning reserves provided in January under this simulation.

Figure 9-24. Generation Pattern in January at Seminoe 5A3

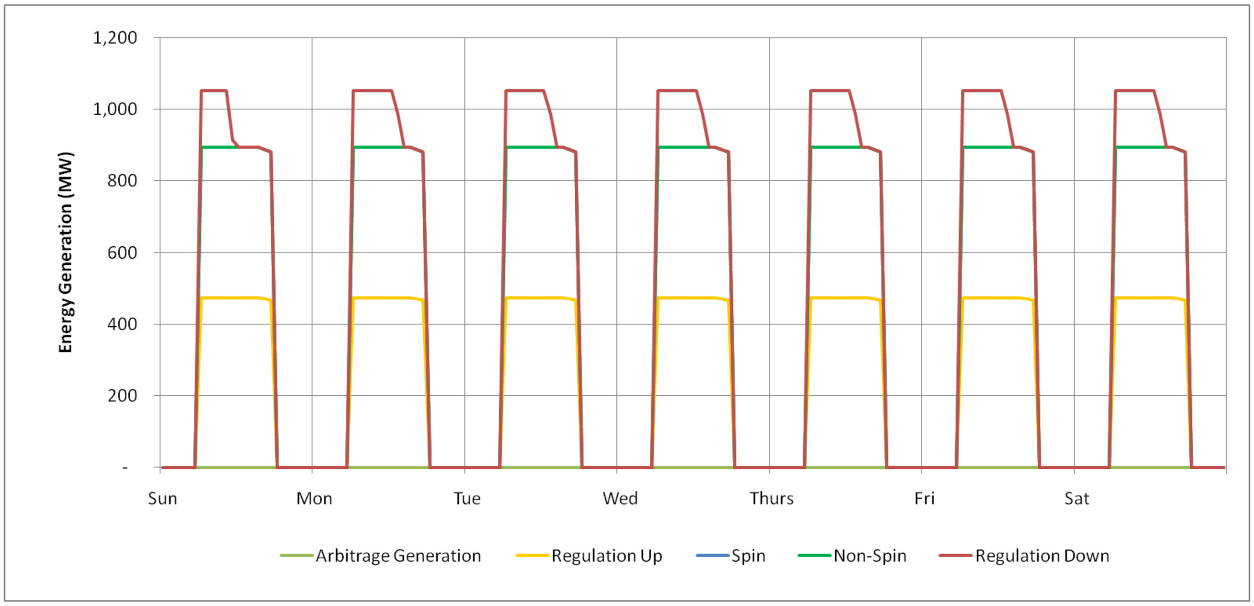
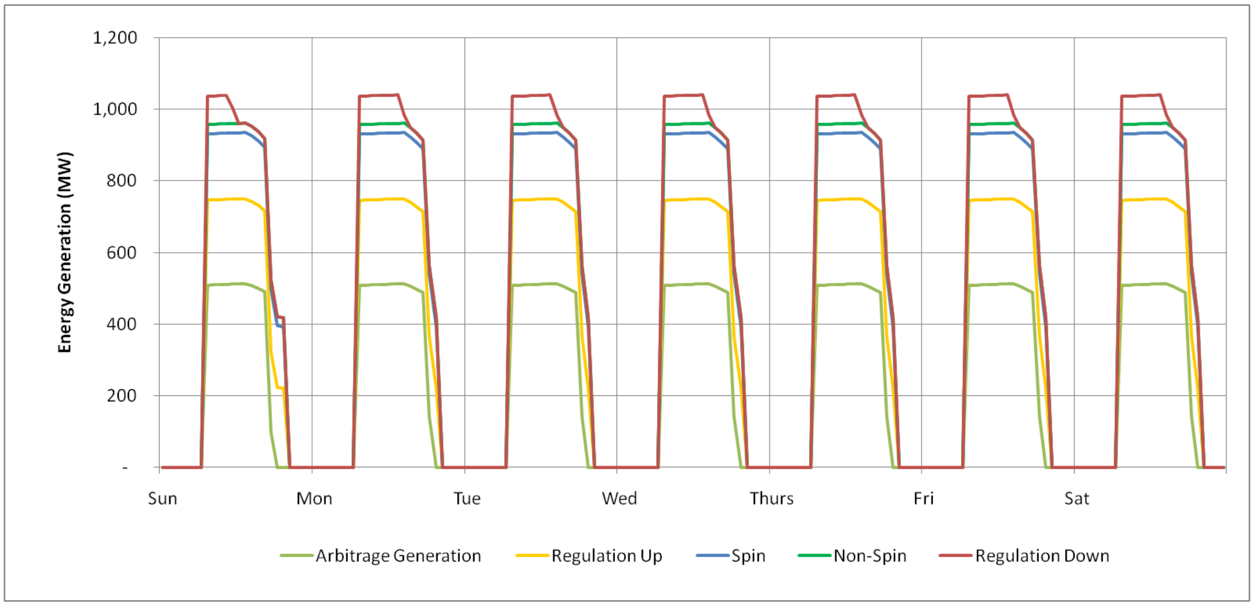


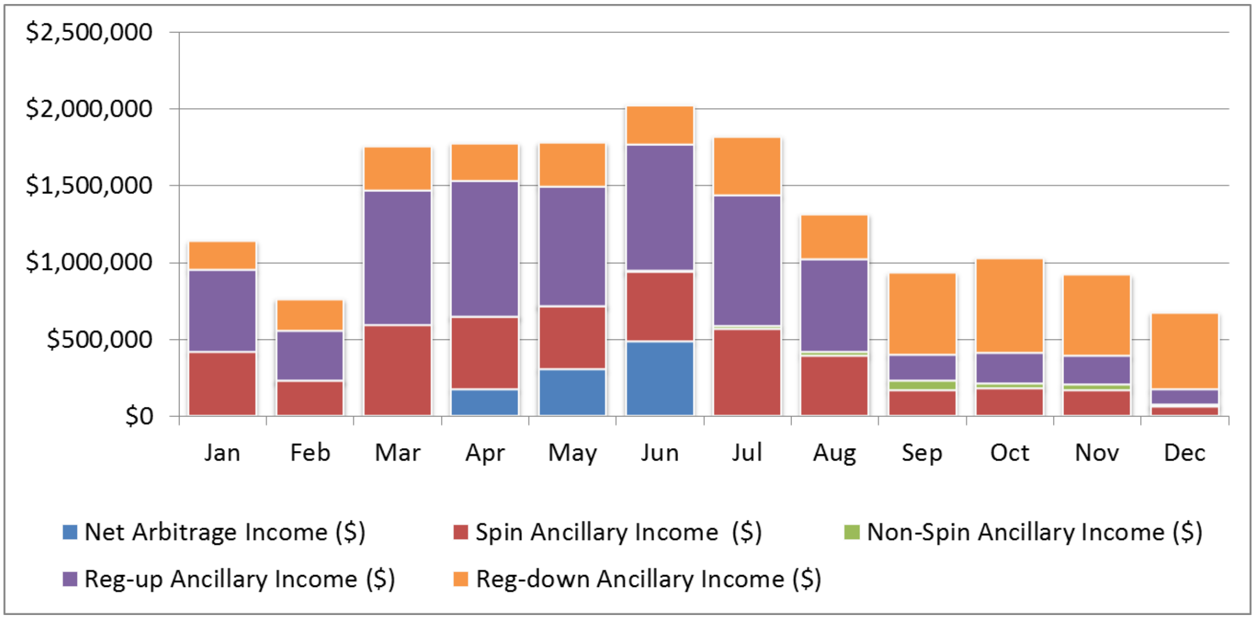
Figure 9-25 shows the generation pattern for a typical week in the month of June for the baseline Seminoe simulation. In June, 50% of the reservoir's storage is dedicated to arbitrage with a peak generation of 500 MW of power produced for arbitrage. The ancillary service pool is divided among the four services with 80% dedicated to regulation up and spinning reserves.

Figure 9-25. Generation Pattern in June at Seminoe 5A3



The average weekly income for each month of the optimized baseline Seminoe simulation is summarized in Figure 9-26. The income mix varies from month to month, with income during April, May and June sourced from arbitrage energy generation and ancillary services. For all other months, all of the income is sourced from ancillary services. The breakdown between ancillary services shows the majority of income is sourced from potential regulation up and down services and spinning reserves. Only a small amount of income is sourced from non-spinning reserve services.

Figure 9-26. Average Weekly Income for the Optimized Baseline Seminoe 5A3



The analysis considered two other Seminoe sites, Seminoe 5A2 and 5C. The configurations vary slightly; Table 9-10 shows a summary of the potential energy served during winter for each of the three Seminoe sites.

Table 9-10. Potential Energy Services Provided Per Unit at Seminoe Sites

Pumped Storage Project Site	Peak Available Pumping Energy (Regulation-Down Services)	Peak Available Generating Energy (Regulation-Up, Spinning, Non-Spinning Services)
Seminoe 5A3	310 MW	270 MW
Seminoe 5A2	220 MW	180 MW
Seminoe 5C	160 MW	130 MW

The average weekly income graphs for Seminoe 5A2 and 5C are shown in Figure 9-27 and 9-28, respectively. The average weekly income generated at both sites is less than that of the Seminoe 5A3 project. Based on these results, the Seminoe 5A3 project provides the most benefit in terms of power and income generation.

Figure 9-27. Average Weekly Income from Seminoe 5A2

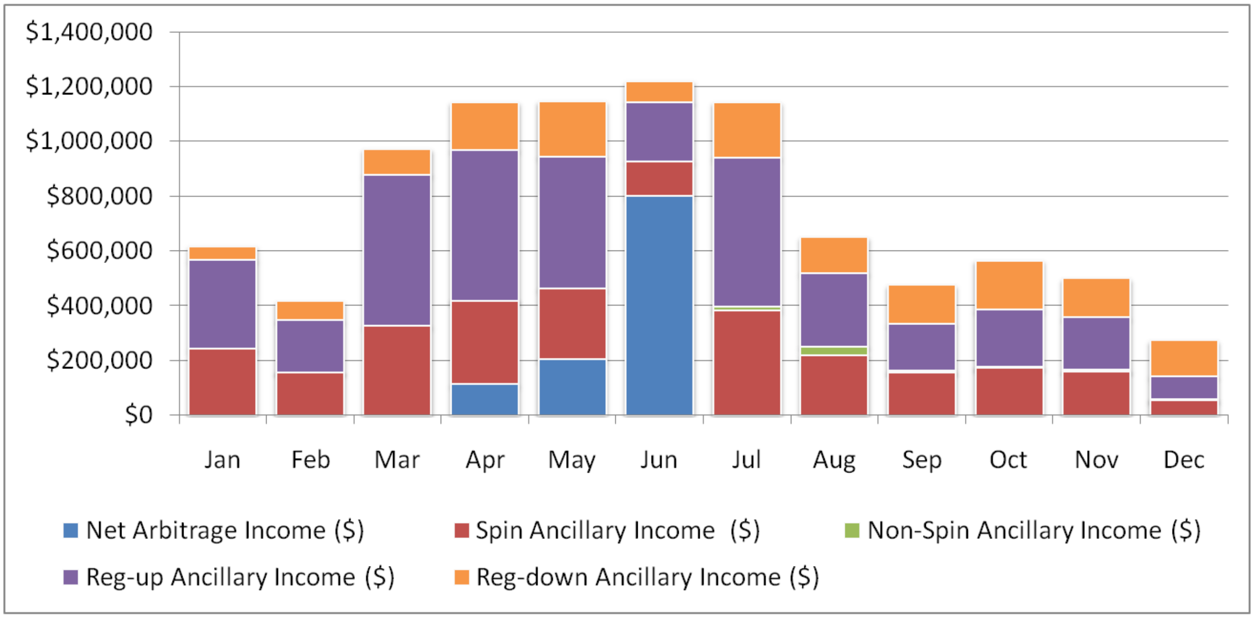
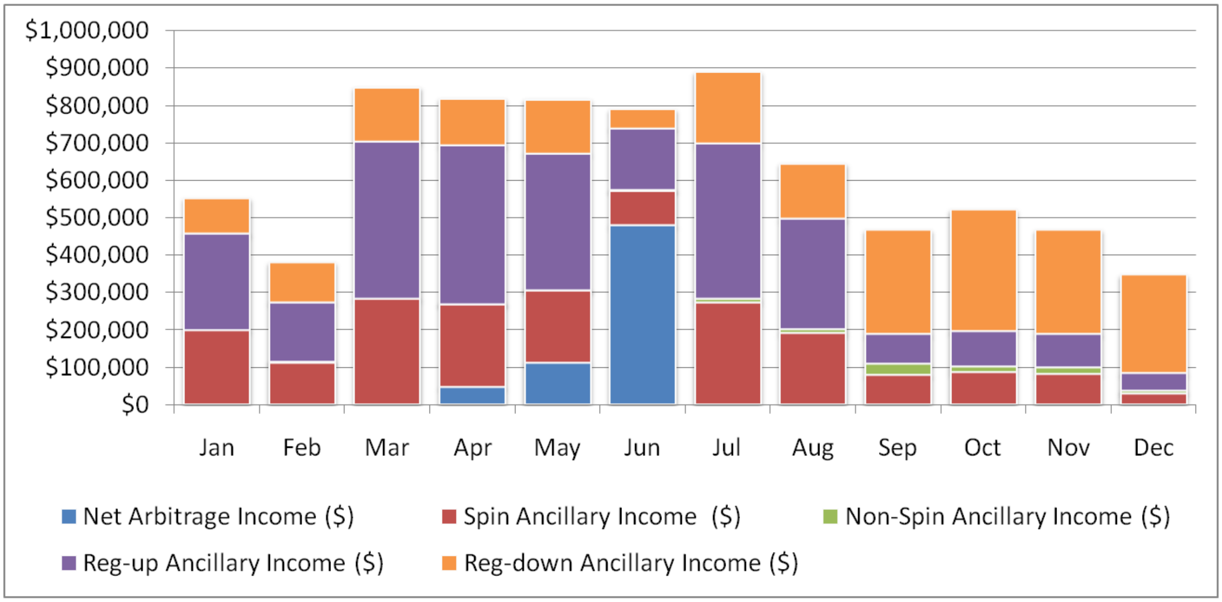


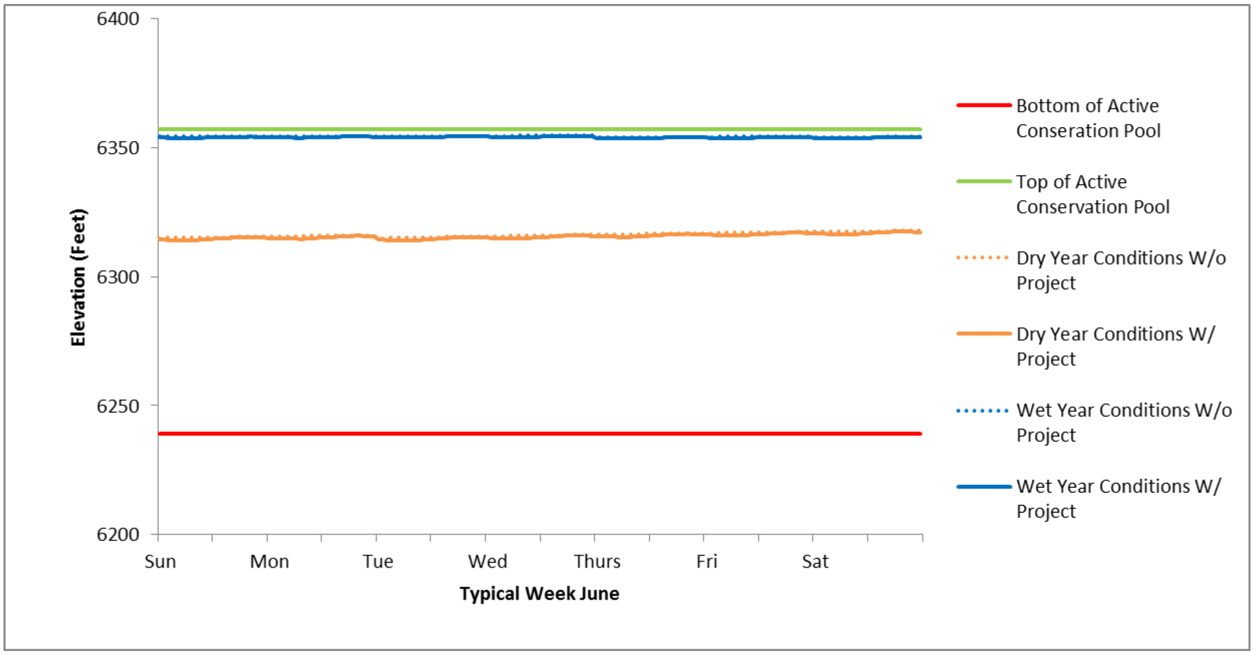
Figure 9-28. Average Weekly Income from Seminoe 5C



9.3.3 Scenario 1 Results

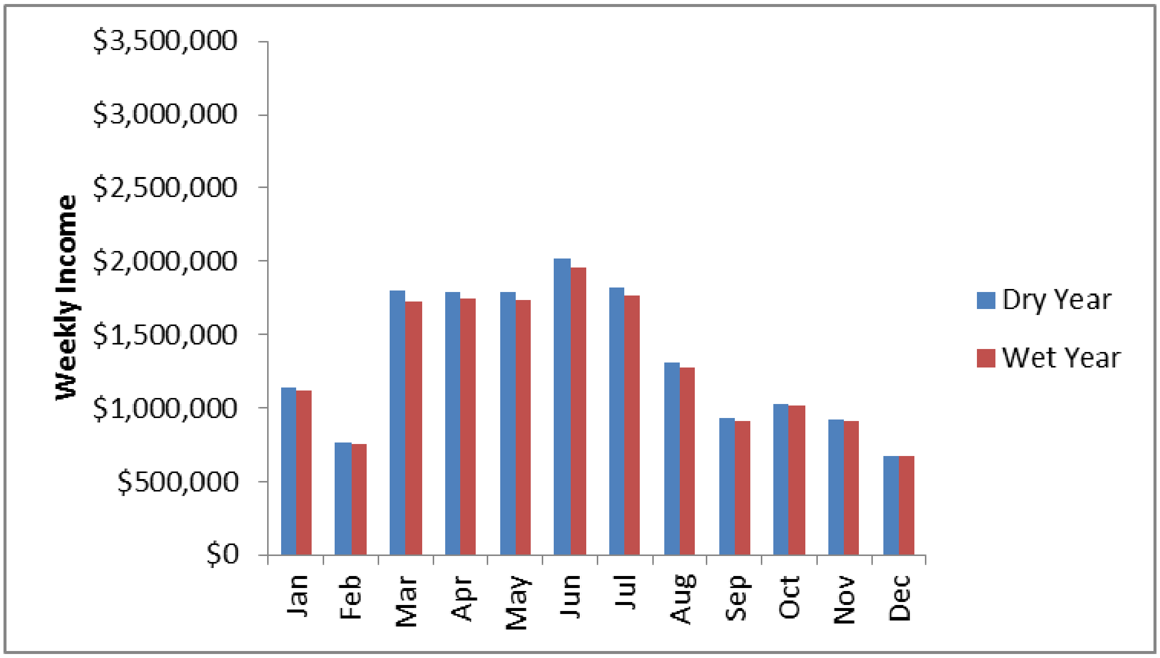
Scenario 1 compares the effects of the Seminoe 5A3 project on Seminoe Reservoir water elevations during dry and wet hydrologic conditions. Based on historic hydrologic data, the year 2003 was used to represent dry year conditions and the year 2000 was used to represent wet year conditions. Similar to the results for the Yellowtail project, the Seminoe project would result in only very small changes to reservoir elevations (approximately 1 foot with the project under dry year conditions and less under wet conditions) but would remain well within the active storage pool. Figure 9-29 shows elevation changes during June (the driest month that includes arbitrage). Because the project would result in such small changes to the reservoir elevation, the Seminoe project would not affect water supplies in Seminoe Reservoir available to meet downstream water and power demands during wet or dry hydrologic conditions.

Figure 9-29. Seminoe Reservoir Elevation during Wet and Dry Hydrologic Conditions with and without the Project



Also similar to the Yellowtail project, the income from the Seminoe project would increase a small amount during dry years (see Figure 9-30). Power generation would increase because of the increased difference in elevation between the two reservoirs.

Figure 9-30. Seminoe Project Average Weekly Income during Wet and Dry Years



9.3.4 Scenario 2 Results

Scenario 2 evaluates how income changes relative to changes in the volume of the energy arbitrage pool. Figure 9-31 shows average weekly energy generated, energy consumed, and turn around efficiency under various pool volumes in June. In general, June is one of the months when the variation in peak and off-peak energy prices make energy arbitrage a more profitable operation relative to other months. Energy arbitrage is always a net consumer of energy, as shown in the figure. As discussed for Yellowtail, the modeled efficiencies are greater than the expected range because of the assumed high pump and generating efficiencies of the variable speed units.

Figure 9-31. Average Weekly Energy Generated and Consumed at Seminoe in June

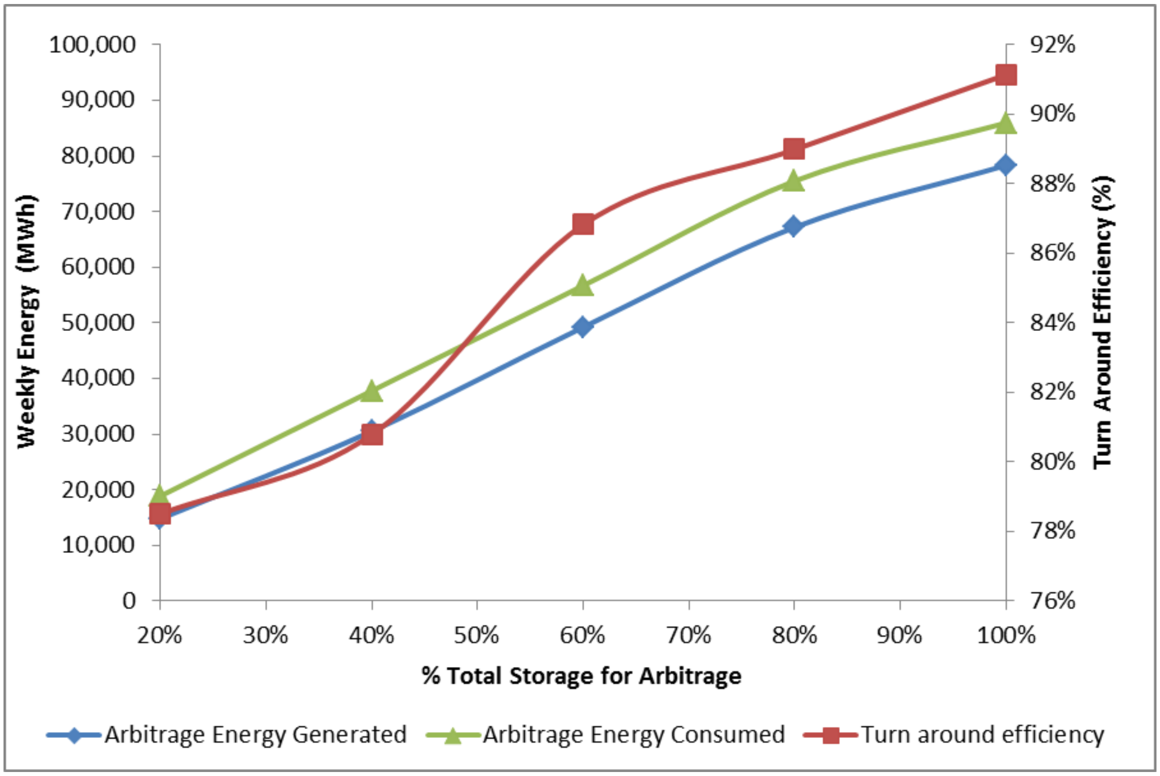
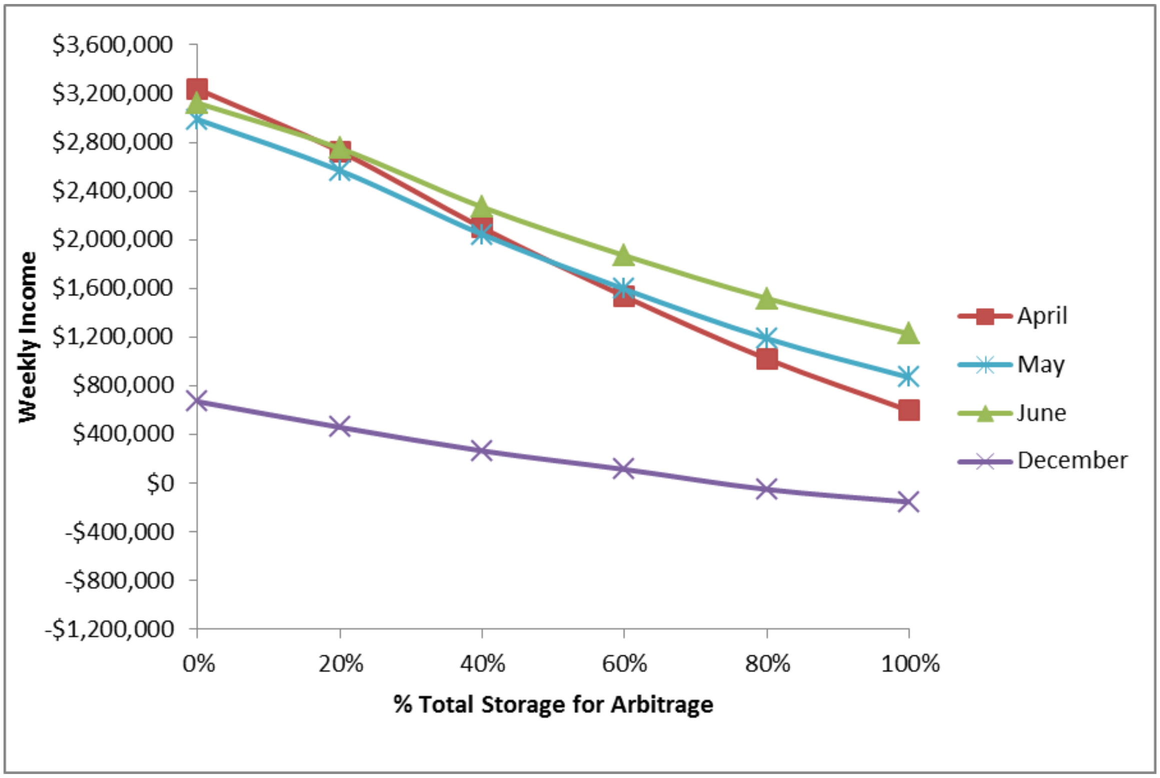


Figure 9-32 shows the average weekly income, from both energy arbitrage and ancillary services, under various energy arbitrage pool volumes and different months. The figure shows April, May, and June, when arbitrage is included in the baseline scenario, and also December, when the model does not include any arbitrage. The trend in the line for December would be similar to other winter months.

Figure 9-32. Average Weekly Income from Arbitrage at Seminoe



More income is generated under arbitrage if there is a greater difference in peak and off-peak energy prices, which typically occurs during the hotter months. During months with relatively flat energy prices, typically winter months, energy arbitrage would not provide substantial income and operations should focus on providing ancillary services. Figure 9-32 shows that weekly income at Seminoe would be maximized by not incorporating any arbitrage. The baseline, however, incorporated arbitrage in April, May, and June because it was profitable based on energy prices. These months were included because it is likely that local utilities would need additional energy in the future to meet peaking demands. Additionally, having some level of pumping or generating can help the system respond instantaneously for regulation services.

9.3.5 Scenario 3 Results

Scenario 3 compares how income would change based on forecasted energy prices with CO_2 regulatory costs and energy prices without CO_2 costs. Figures 9-33 and 9-34 show typical week energy prices for both price options in June and December, respectively. June shows summer conditions in a month when arbitrage is considered, and December shows winter conditions when the project will only provide ancillary services. In June, the energy prices increase with CO_2 regulatory costs when the system would be pumping and generating. The energy prices also flatten so the differences between peak and non-peak prices decrease, thereby decreasing income from energy arbitrage. In

December, the prices increase because of CO_2 regulatory costs, but there is still little variation between peak and non-peak prices.

Figure 9-33. Typical Week Energy Prices at Seminoe in June with and without CO_2 Regulatory Costs

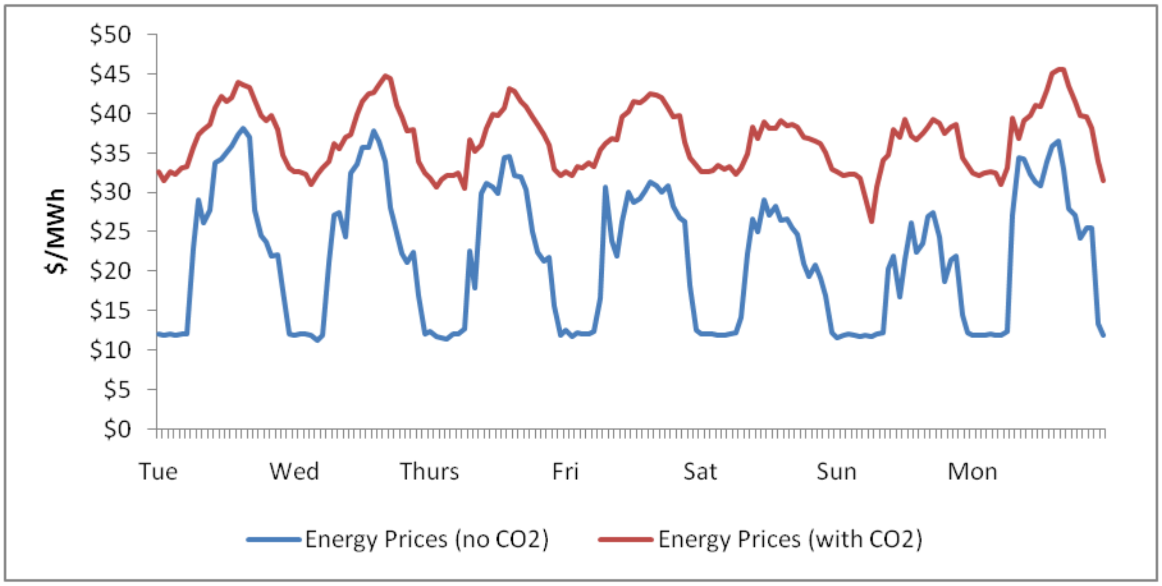


Figure 9-34. Typical Week Energy Prices at Seminoe in December with and without CO_2 Regulatory Costs

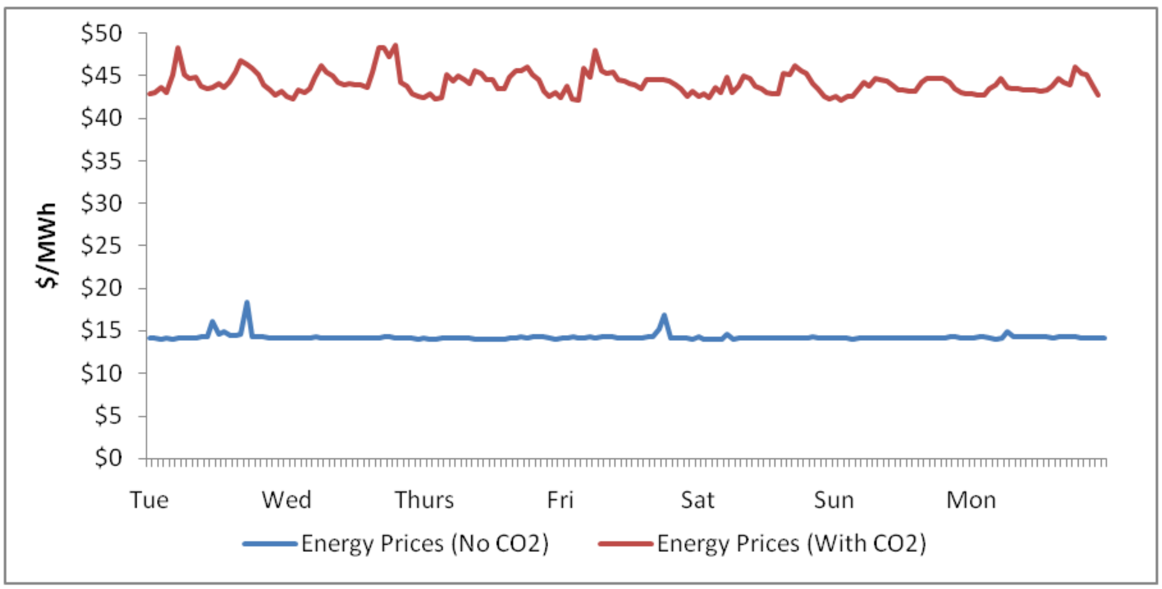
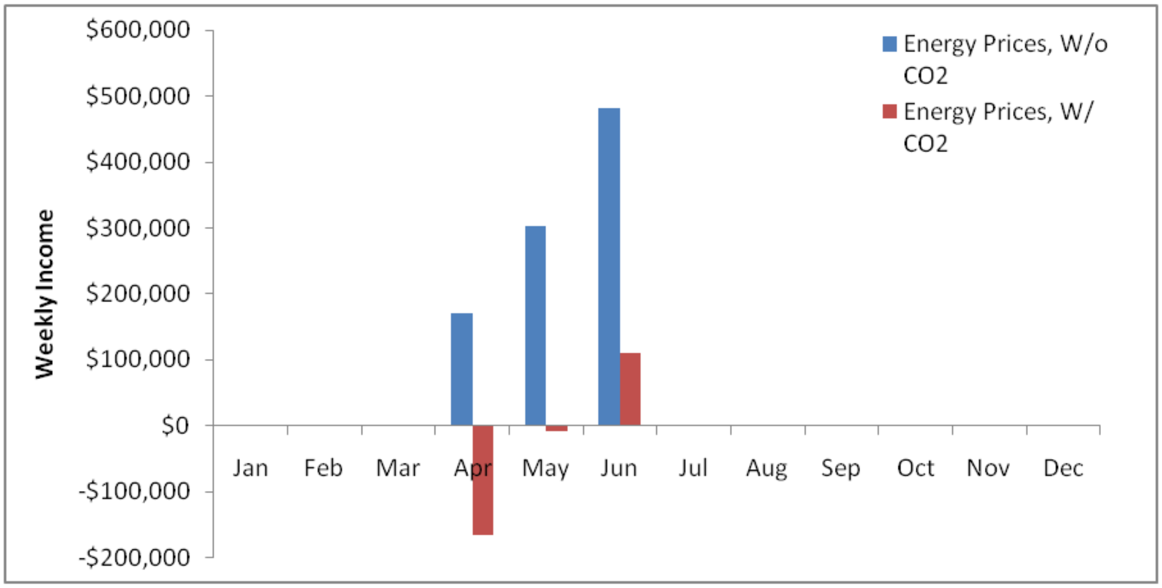


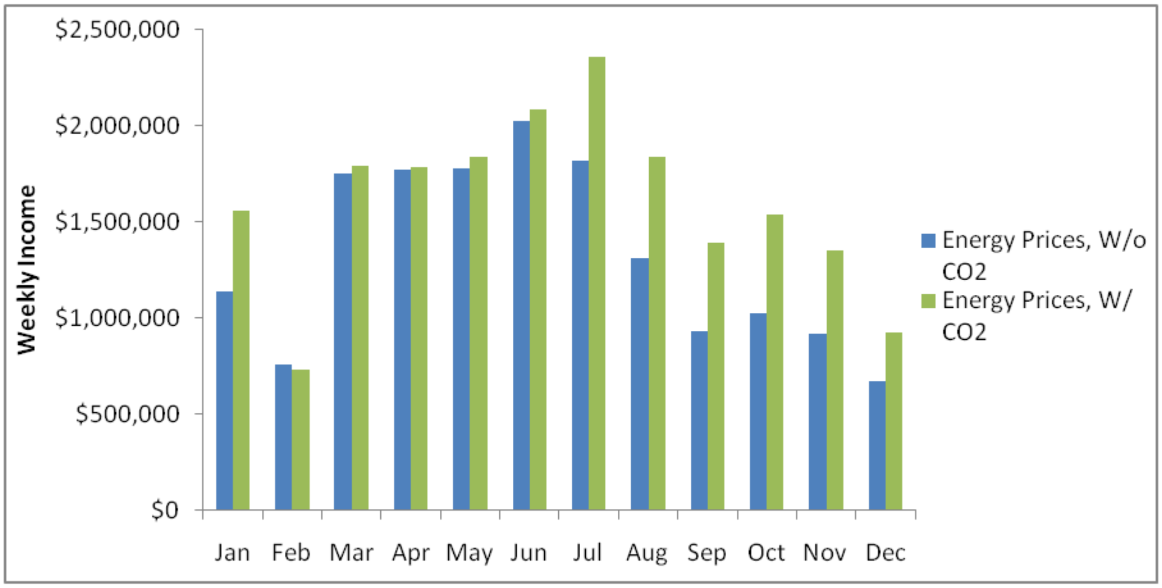
Figure 9-35 shows average weekly arbitrage income (not including ancillary services income) of the base case scenario using CO_2 prices compared to without CO_2 prices. Because of the difference in monthly energy prices, arbitrage operations would lose money in April and May and generate only a small amount of income in June.

Figure 9-35. Average Weekly Arbitrage Income at Seminoe with and without CO_2 Regulatory Costs



Energy prices with CO_2 follow a different daily pattern than prices without CO_2, including peaks and valleys at slightly different times of day. Changing the schedule of when arbitrage operations pump and generate during each day increased the income from these operations. After this optimization, arbitrage was profitable in April, May, and June. Figure 9-36 shows total (energy arbitrage and ancillary services) average weekly income under operation scenarios that maximize income using both energy prices with and without CO_2. The income generated based on energy prices with CO_2 would be more in the summer months because the project would be largely operated to provide ancillary services. Income would be higher in the winter months because the with CO_2 prices are higher than the without CO_2 prices for all ancillary services deployed.

Figure 9-36. Average Weekly Income at Seminoe with and without CO_2 Regulatory Costs



9.3.6 Scenario 4 Results

Scenario 4 tests the sensitivity of income to changes in ancillary service prices. As discussed earlier, forecasts are not available for ancillary service prices, but in general, most experts believe that prices will increase because of increased production of renewable energy resources. Figures 9-37 through 9-40 show average weekly income by month in 2032 for the four ancillary services under each escalation option (described in Section 9.1.5). The escalation options are estimated based on the same proportions of arbitrage and ancillary services in the baseline. April, May, and June would have lower ancillary service income because a portion of the new reservoir pool is dedicated to energy arbitrage. As in the base case scenario, regulation up and down services and ancillary services would provide the most income.

Figure 9-37. Average Weekly Income from Spin Ancillary Services at Seminoe

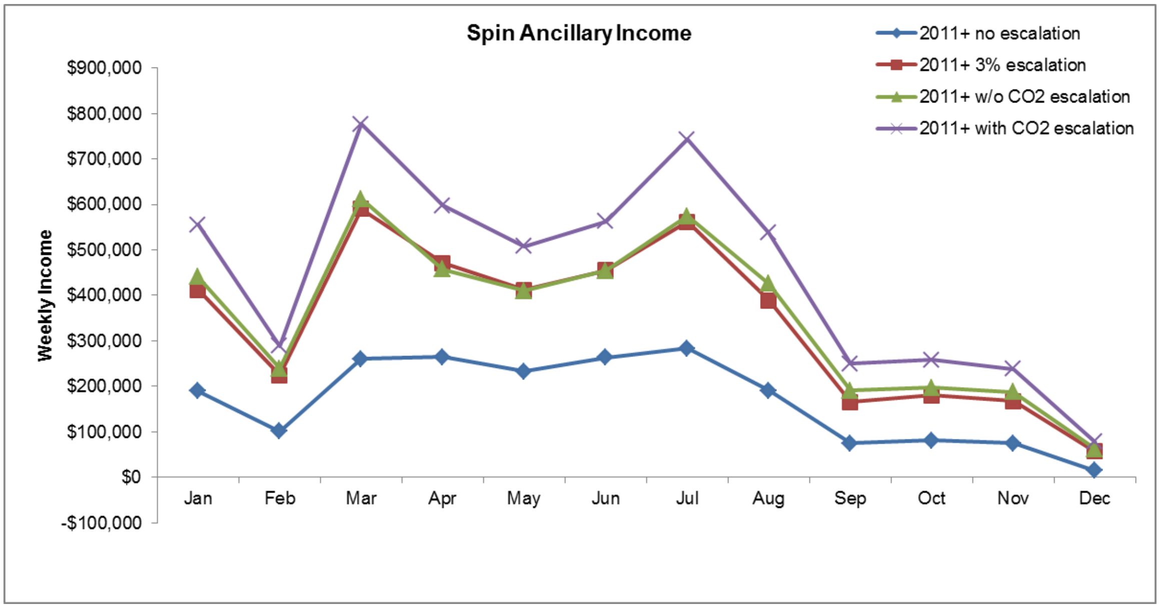


Figure 9-38. Average Weekly Income from Non-Spin Ancillary Services at Seminoe

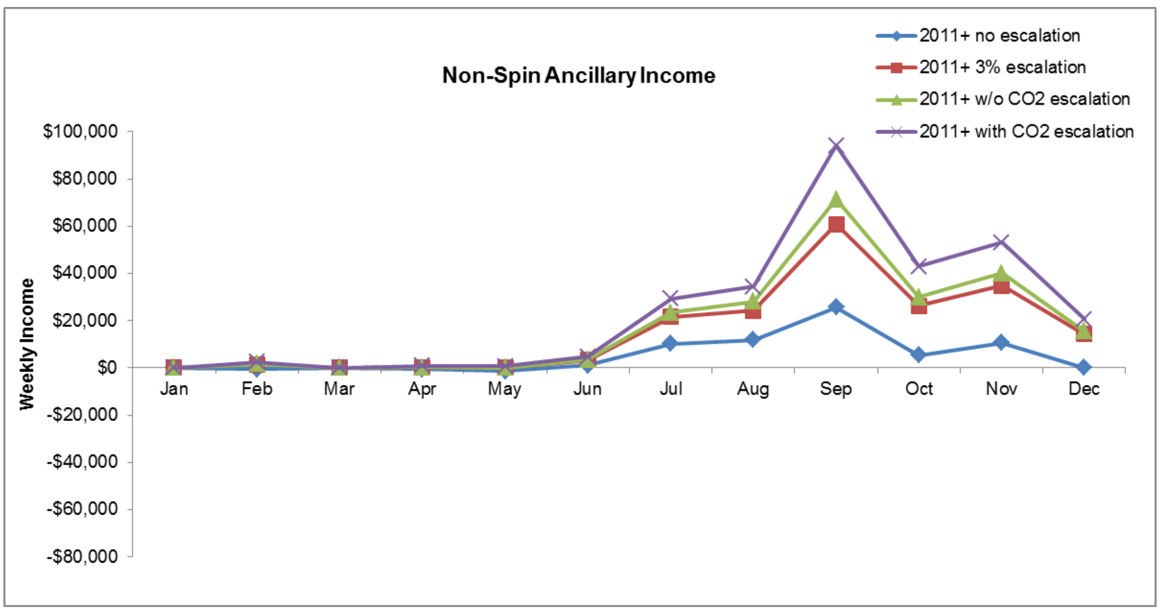


Figure 9-39. Average Weekly Income from Regulation Up Ancillary Services at Seminoe

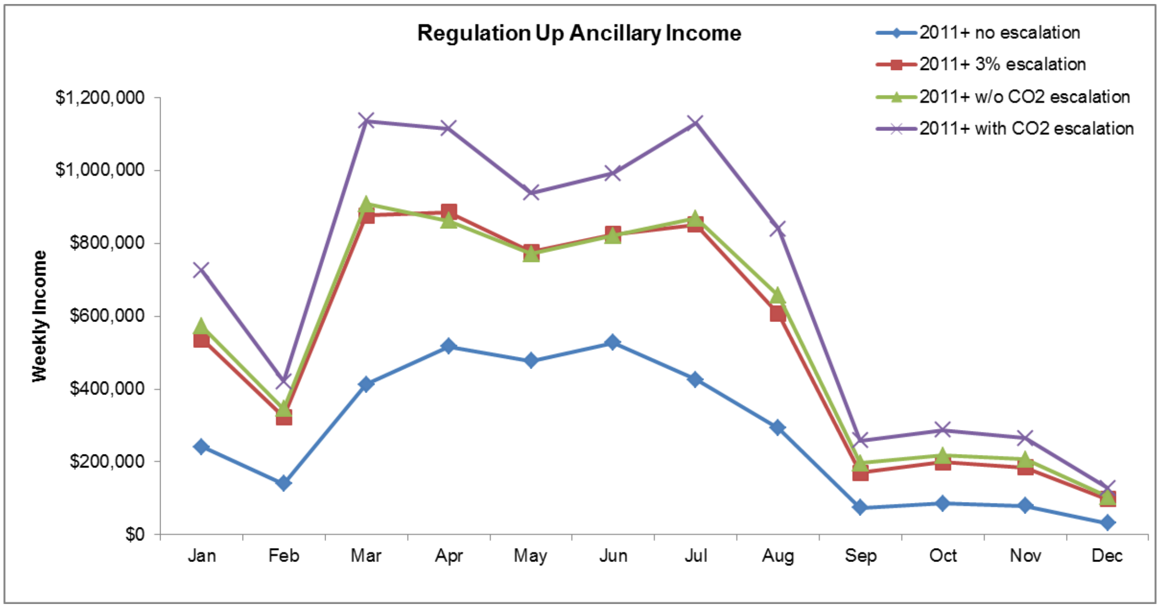


Figure 9-40. Average Weekly Income from Regulation Down Ancillary Services at Seminoe

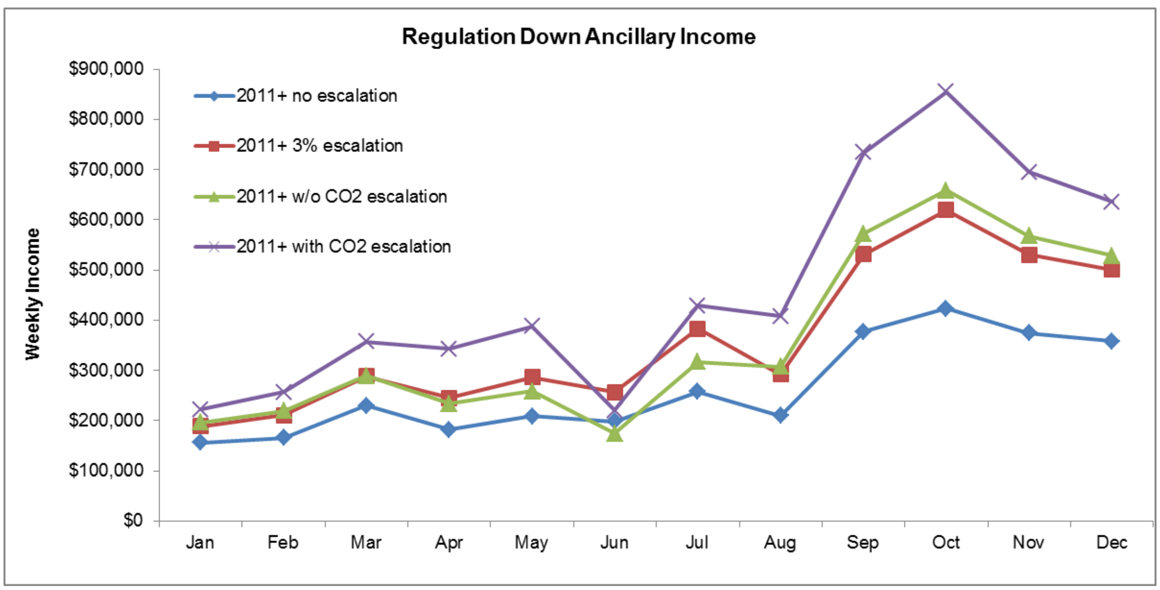
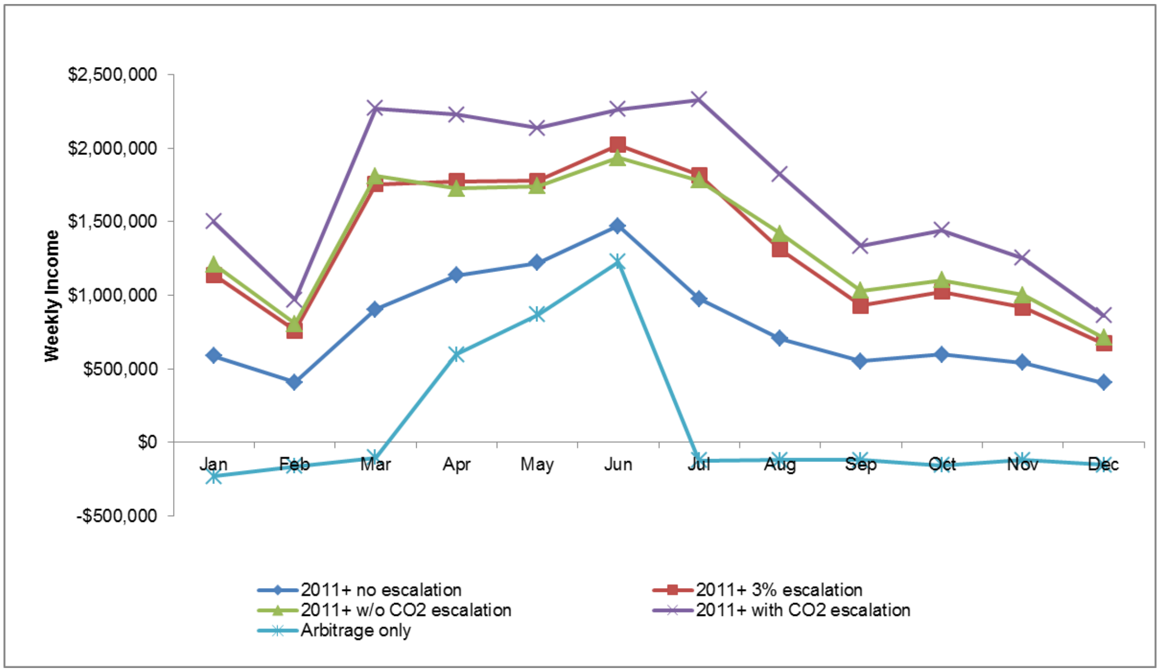


Figure 9-41 shows average weekly total income, which includes energy arbitrage and ancillary services, under the various ancillary service price forecasts. This figure shows that increases in future ancillary service prices relative to no escalation would substantially improve the project's total income. The weekly income for arbitrage only is also shown on Figure 9-41 and highlights how ancillary services add to the total income of the project. Only the months of April, May, and June would produce a positive net income under an arbitrage-only operation.

Figure 9-41. Average Weekly Income with Varying Escalation at Seminoe



9.3.7 Scenario 5 Results

The objective of Scenario 5 is to assess the impact of climate change in the system's ability to respond to water needs for water and energy generation demands. The most critical measure of impact is the frequency of future use restrictions due to decreased water levels. If precipitation changes due to climate change are significant to the point that water levels in Seminoe Reservoir would drop under the bottom of the active conservation pool, future operations would be compromised or restricted. Thus the climate change analysis focuses on determining the likelihood of significant reductions in precipitation in Seminoe Reservoir's catchment area and runoff into the lake.

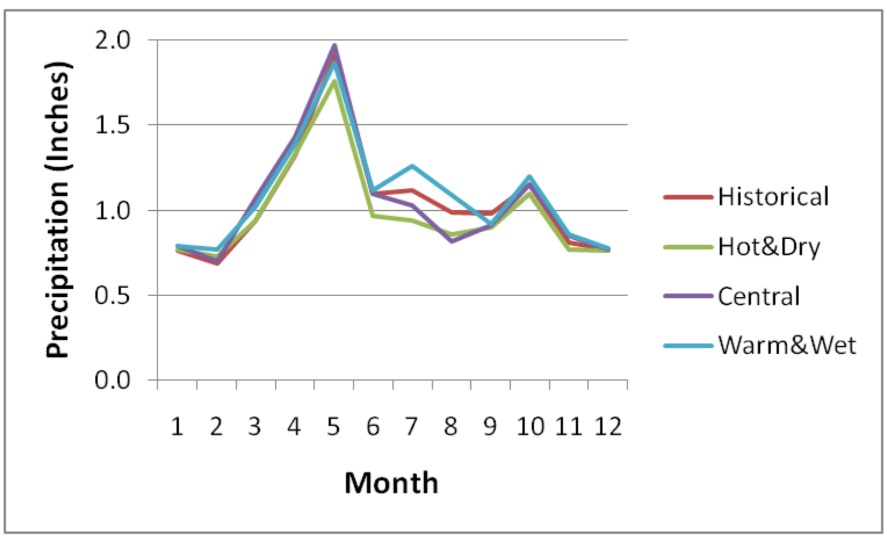
Assuming the same operational objectives (driving operational flows), the most significant impacts related to water level in Seminoe Reservoir are evaporation and natural inflows. Evaporation has not been included in any of the scenarios analyzed in this analysis and it is also excluded from the analysis in the climate change scenario, for consistency.

Related to impact on inflows into the lake, the overall approach consisted on obtaining projections of precipitation in the area under climate change conditions and indications of runoff changes as a result. The main two sources of information used in the analysis were the SECURE Water report (SECURE Water Act Section 9503(c) – Reclamation Climate Change and Water 2011) and the databases available in the CREAT Tool developed by EPA. The CREAT (version 2.0) database includes multiple climate model projections providing a distribution of possible future conditions for each specific locations.

Seminoe Reservoir is part of the Missouri basin, which, while being a very extensive basin, is generally projected to experience increases in precipitation (Reclamation, 2011. p92). This includes general area of Seminoe Reservoir's catchment where the runoff to the lake generates. The closes sub basin reported in the SECURE Water study (Reclamation, 2011. p98) is the Milk River basin at Nashua Montana, where the mean annual runoff is projected to increase over 8 percent by the 2050s. The mean December-March runoff and the mean April-July runoff are also projected to increase. The Milk River Basin, however, is considerably distant from Seminoe Reservoir requiring additional data for the analysis, as described below.

To provide additional geographic specificity, the CREAT Tool was used to obtain precipitation data for the Seminoe Reservoir catchment area. Three groups of predictions were used from models that tend to predict “Hot and Dry” years, “Central” models, and models predicting “Warm and Wet” years. A summary of precipitation by month for each of these three types of predictions for the 2030s was compared to historical data, with results presented in Figure 9-42, which shows a minimal change in precipitation in the Seminoe Reservoir area. The annual precipitation historically is 12.5 inches while the precipitation for the three types of climate change projections ranges from 11.8 to 13.1inches per year.

Figure 9-42. Monthly Precipitation (inches) Comparison for Historical Record vs. Climate Change Projections for the Seminoe Reservoir Area



Given the minimal projected impact of climate change in precipitation and runoff for the Seminoe Reservoir area, climate change conditions (as predicted by the models used in this analysis) will most likely not have an impact on the pump-storage operations at the Seminoe site.

9.4 Trinity Operations Analysis

This section presents the results of the base case and scenarios analysis for the Trinity 5G2 alternative.

9.4.1 Model Inputs

Table 9-11 shows the model inputs for facilities used in the Trinity model.

Table 9-11. Trinity Model Inputs

Model Parameter	Parameter Value Used in Baseline Trinity Simulation
New Reservoir Capacity	15,022 AF
Pump Flow (Max)	4,483 cfs
Pump Efficiency	0.902
Generating Flow (Max)	4,444 cfs
Turbine Capacity	239 MW
Min Allowable Forebay Elev	2,145 ft (Bottom of Active Conservation Pool)
Max Upper Water Elev	3,105 ft

The peak price ratio for the baseline Trinity simulation is summarized in Table 9-12 below. Overall, the peak price ratios for Trinity are lower than the baseline Yellowtail simulation, but higher than the baseline Seminoe simulation.

Table 9-12. Peak Energy Price Ratio for Trinity Baseline

Month of Simulation	Peak Energy Price Ratio [Peak/Off-Peak]	Percentage of Reservoir Storage Dedicated to Arbitrage
January	1.36	0%
February	1.34	0%
March	1.72	0%
April	2.27	70%
May	3.88	80%
June	5.38	90%
July	2.55	80%
August	1.78	0%
September	1.52	0%
October	1.48	0%
November	1.32	0%
December	1.37	0%

Using the peak price ratio guidance of 2.0 and additional manual optimization, it was determined that arbitrage energy generation would be feasible in April, May, June, and July of the simulation. The optimized pumping and generating schedule for these months is summarized in Table 9-13.

Table 9-13. Trinity Optimized Pump/Generation Schedule for Arbitrage

Time of Day	Operation
Hours 1 - 8	PUMP
Hours 9 – 21	GENERATE
Hours 22 - 24	PUMP

In all other months, the reservoir volume dedicated to ancillary services was set to 100% (no arbitrage energy generation). The size of each ancillary service pool was also manually optimized to increase potential income. Table 9-14 shows the proportions of each ancillary service relative to the ancillary service pool for each month.

Table 9-14. Ancillary Service Pool Sizes for Trinity Baseline Simulation

Month of Simulation	Spinning Reserves	Non-Spinning Reserves	Regulation Up	Regulation Down
January	30%	0%	60%	10%
February	30%	0%	60%	10%
March	30%	0%	60%	10%
April	25%	5%	60%	10%
May	30%	0%	60%	10%
June	25%	5%	60%	10%
July	25%	5%	60%	10%
August	25%	5%	60%	10%
September	25%	5%	60%	10%
October	25%	5%	60%	10%
November	25%	5%	60%	10%
December	30%	0%	60%	10%

9.4.2 Trinity Base Case Results – Maximize Income

Figure 9-43 is a stacked line graph showing the generation pattern for a typical week in the month of January in the baseline Trinity simulation. In January, all of the potential power generation/absorption is dedicated to ancillary services. The potential energy for regulation up, spinning, and non-spinning services is approximately 940 MW when the pumped storage project is generating. This simulation dedicates 60% of the reservoir volume for regulation up, 30% for spinning reserves, and 10% for regulation down. There is no pool set aside for non-spinning reserves.

Figure 9-43. Generation Pattern in January at Trinity

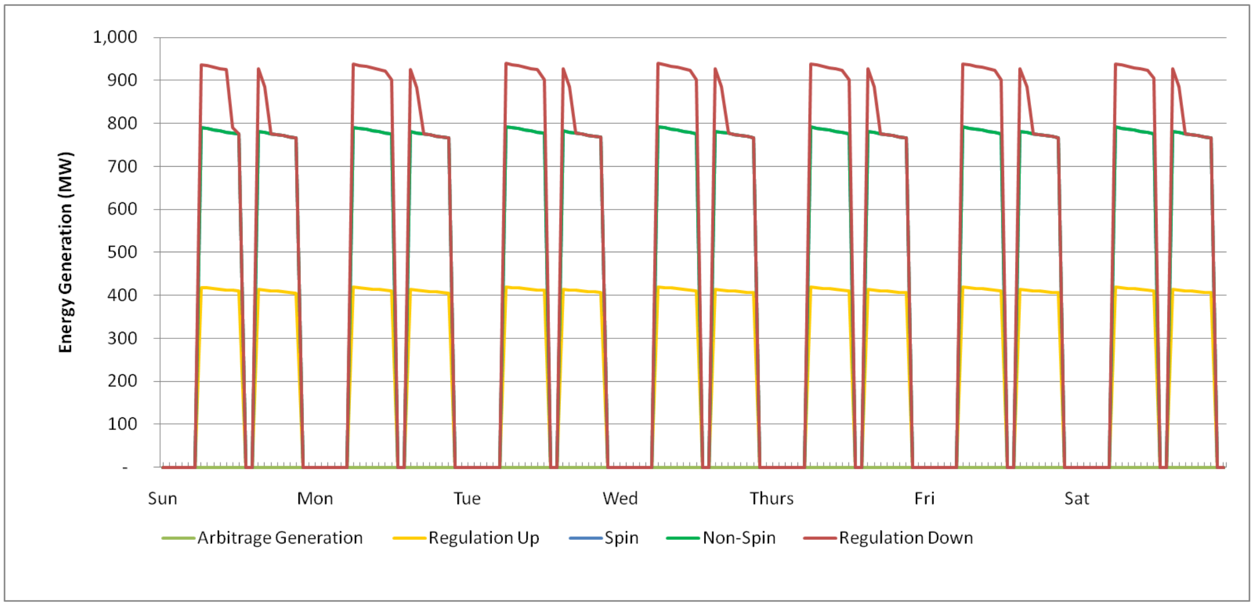
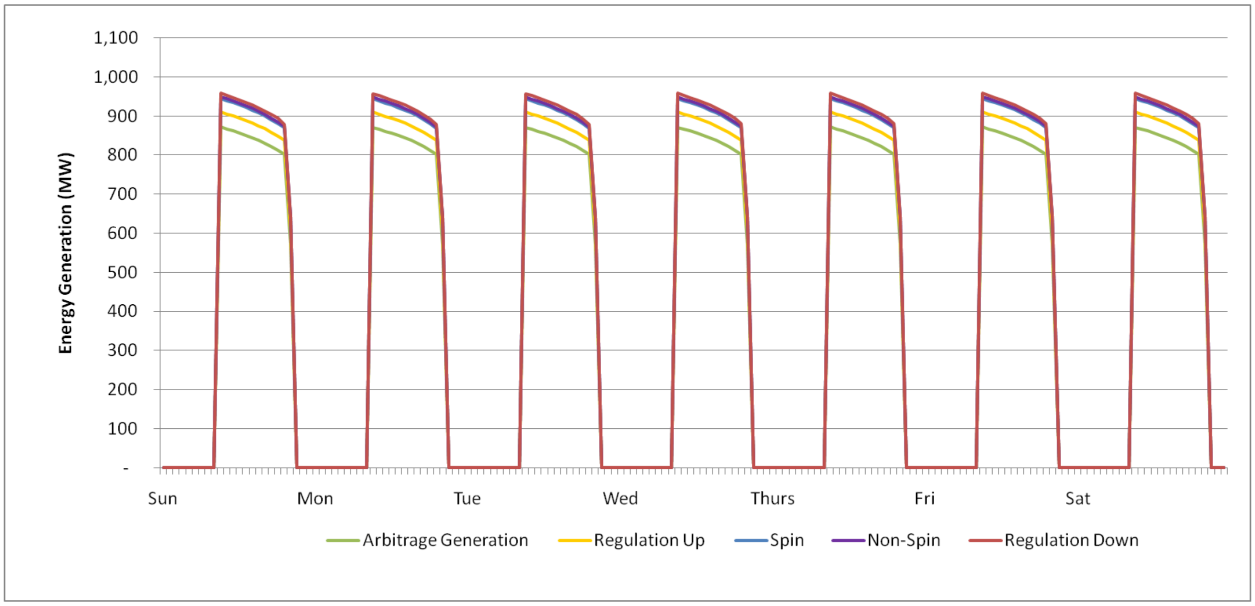


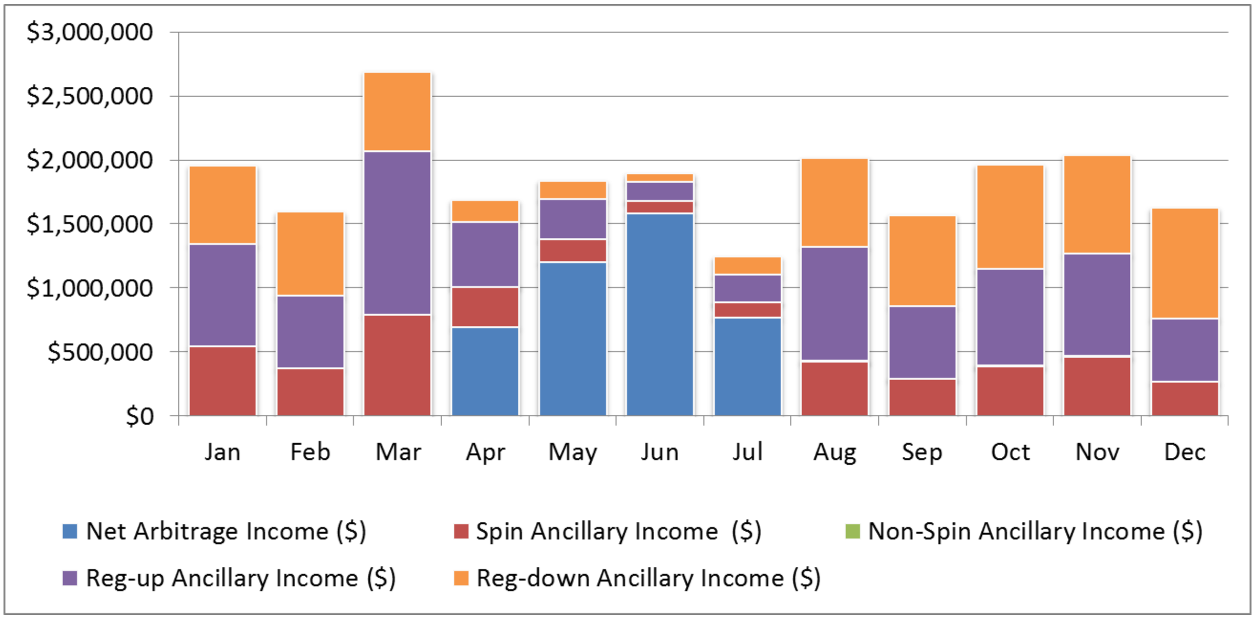
Figure 9-44 shows the generation pattern for a typical week in June for the baseline Trinity simulation. In June, 90 percent of the reservoir's storage is dedicated to arbitrage with a peak generation of approximately 850 MW of power produced for arbitrage, and minimal power available to meet ancillary benefits.

Figure 9-44. Generation Pattern in June at Trinity



The average weekly income for each month of the optimized baseline Trinity simulation is summarized in Figure 9-45. The income mix varies from month to month, with income during April, May, June, and July sourced from arbitrage energy generation and ancillary services. For the remaining months, all of the income is sourced from ancillary services. The breakdown between ancillary services shows the majority of income is sourced from potential regulation up and down services and spinning reserves. Only a small amount of income is sourced from non-spinning reserve services. March generated a higher income because the average ancillary service prices are higher relative to other months.

Figure 9-45. Average Weekly Income for the Optimized Baseline Trinity Scenario



9.2.3 Scenario 1 Results

Scenario 1 compares the effects of the Trinity project on Trinity Reservoir water elevations during dry and wet hydrologic conditions. Based on historic hydrologic data, the year 1991 was used to represent dry year conditions and the year 1998 was used to represent wet year conditions. Similar to the results for the other projects, the Trinity project would result in only very small changes to reservoir elevations (approximately one foot under both dry and wet conditions) but would remain well within the active storage pool. Figure 9-46 shows Trinity Reservoir elevation changes during a typical week in July (the driest month that includes arbitrage). Because the project would result in such small changes to the reservoir elevation, the Trinity project would not affect water supplies in Trinity Reservoir available to meet downstream water and power demands during wet or dry hydrologic conditions.

Figure 9-46. Trinity Reservoir Elevation during Wet and Dry Hydrologic Conditions with and without the Project

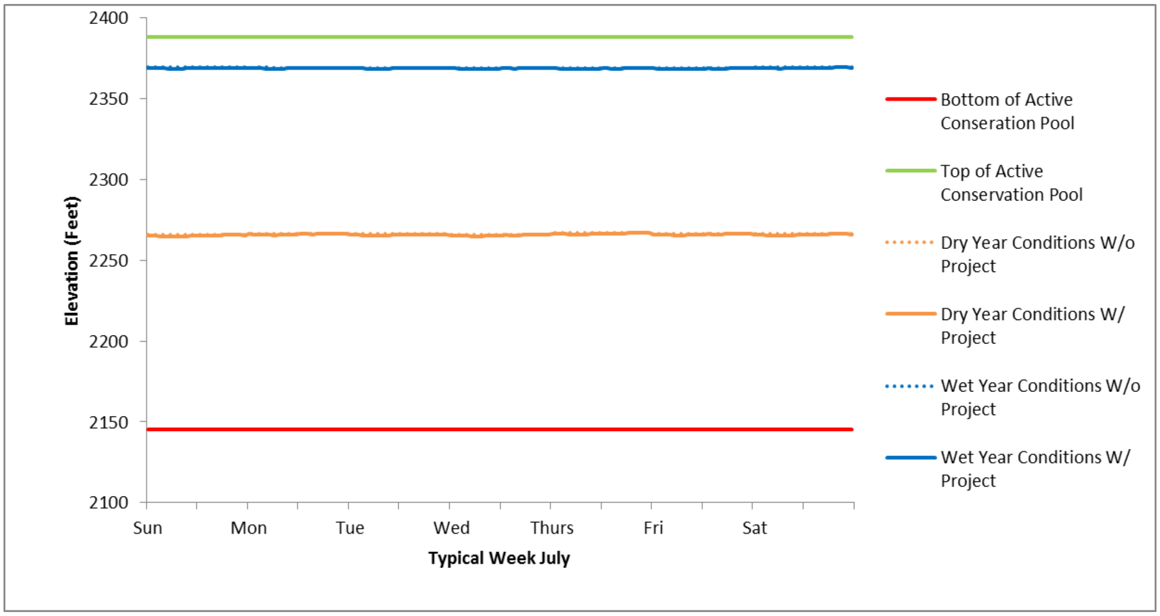
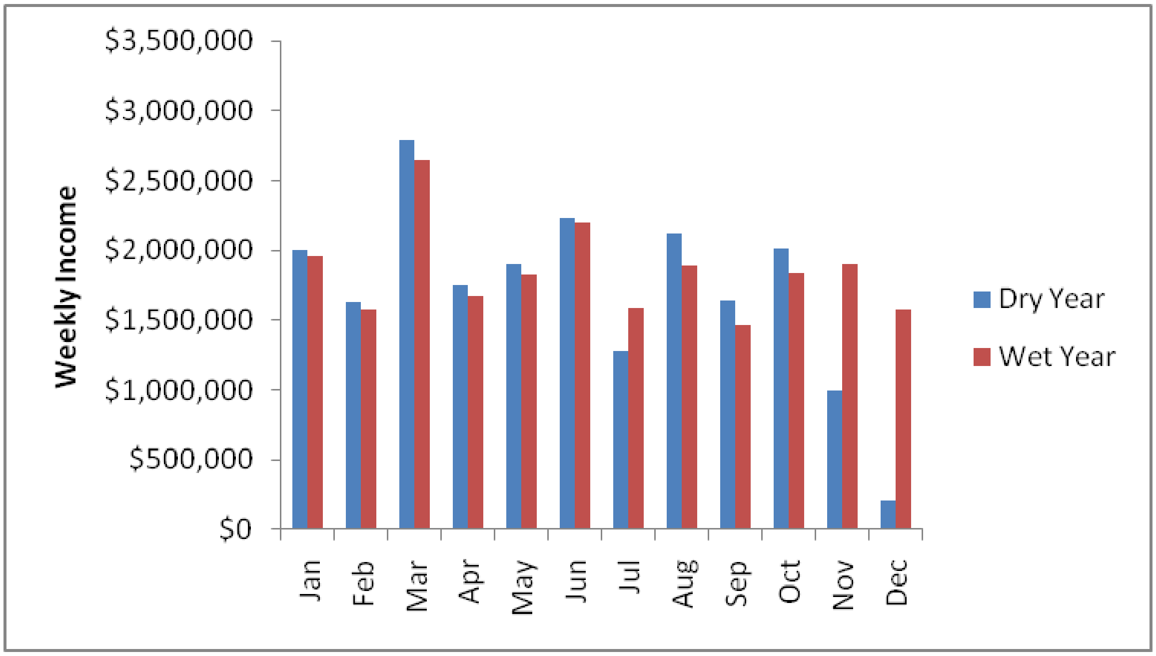


Figure 9-47 shows average weekly income each month over dry year (1991) and wet year (1998) conditions, including both arbitrage and ancillary services income. Income would be similar in most months, but slightly higher during dry years because of increased head available when the reservoir is being operated for arbitrage. November and December show different results in the dry year. In 1991, the head was above the operating range for the turbines for the entire month of December and parts of November. At these times, energy could not be generated; therefore, the income in a dry year is less than the wet year.

Figure 9-47. Trinity Project Average Weekly Income during Wet and Dry Years



9.2.4 Scenario 2 Results

Scenario 2 evaluates how income changes relative to changes in the volume of the energy arbitrage pool. Figure 9-48 shows average weekly energy generated, energy consumed, and turn around efficiency under various pool volumes in June. In general, June is one of the months when the variation in peak and off-peak energy prices make energy arbitrage a more profitable operation relative to other months. Energy arbitrage is always a net consumer of energy, as shown in the figure. As discussed above, the modeled efficiencies are greater than the expected range because of the assumed high pump and generating efficiencies of the variable speed units.

Figure 9-48. Average Weekly Energy Generated and Consumed at Trinity in June

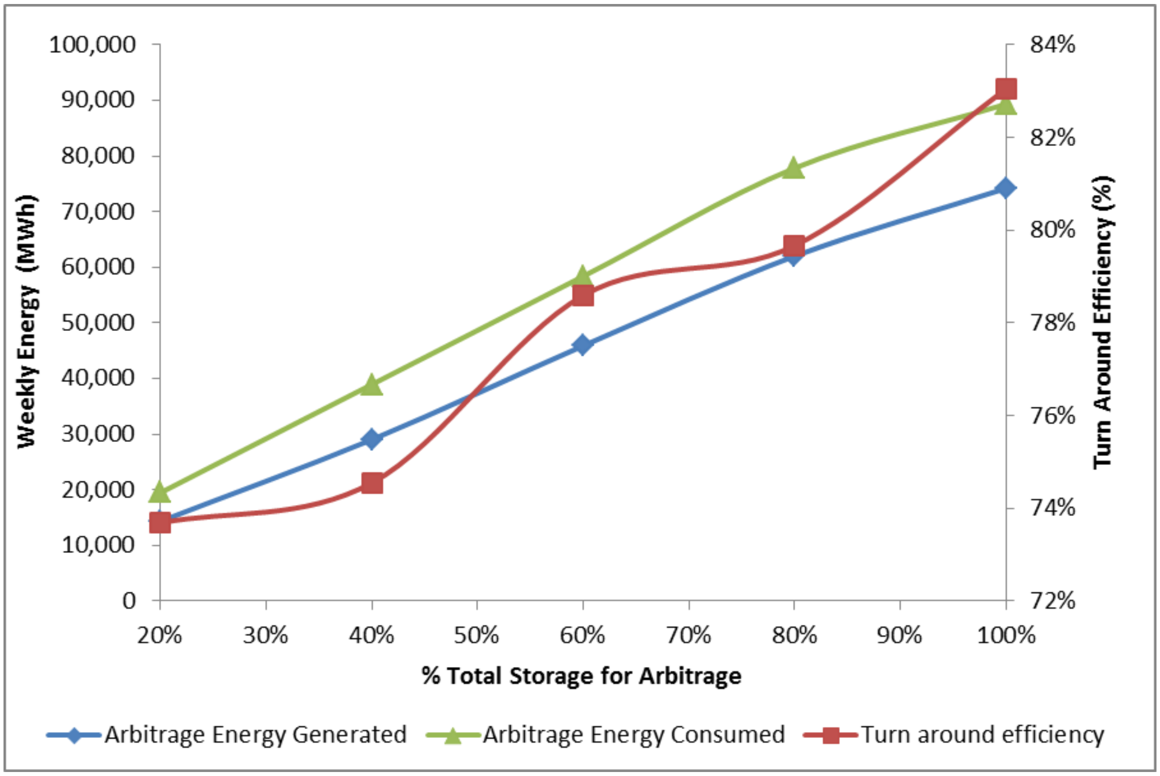
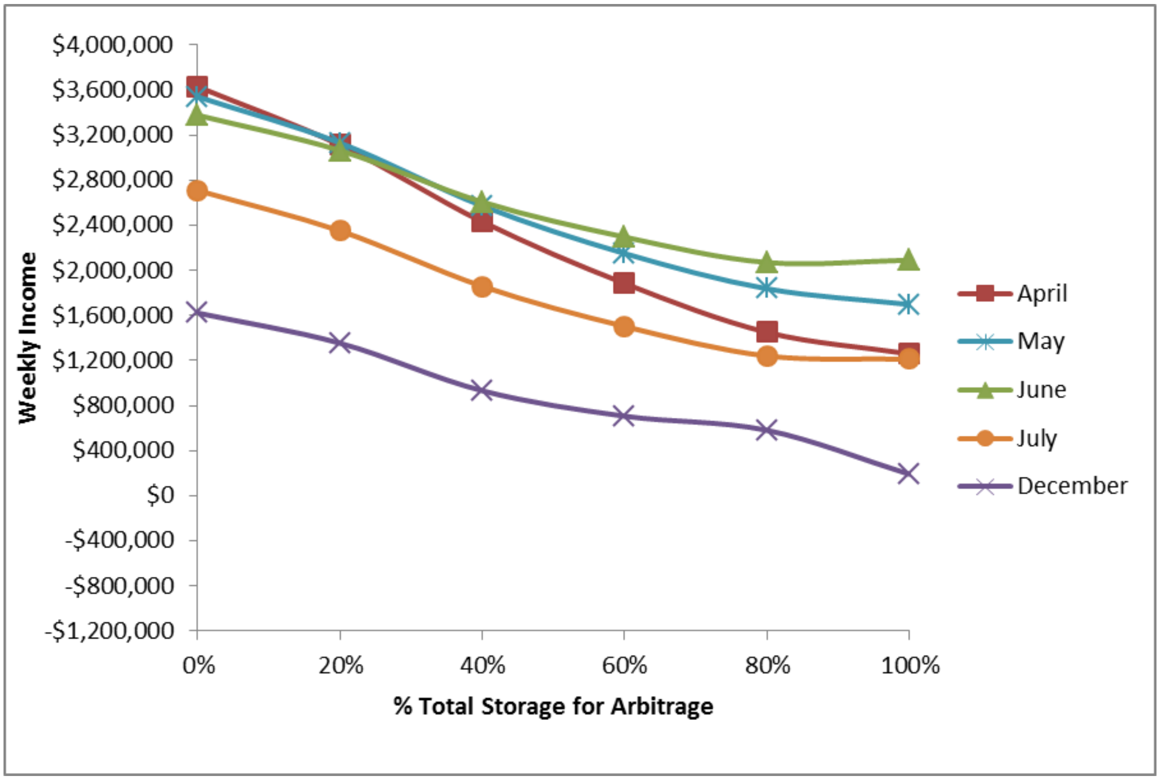


Figure 9-49 shows average weekly income, from both energy arbitrage and ancillary services, under various energy arbitrage pool volumes and different months. The figure shows the months when the base case scenario operations include energy arbitrage (April, May, June, and July) and also December, when the model does not include any arbitrage. The trend in the line for December would be similar to other winter months.

Figure 9-49. Average Weekly Income from Arbitrage at Trinity



More income is generated under arbitrage if there is a greater difference in peak and off peak energy prices, which typically occurs during the hotter months. During months with relatively flat energy prices, typically the winter months, energy arbitrage would not provide substantial income and operations should focus on providing ancillary services to maximize income. Figure 9-50 shows that weekly income at Trinity would be maximized by not incorporating any arbitrage. The baseline, however, incorporated arbitrage in April, May, June, and July because it was profitable based on energy prices. These months were included because it is likely that local utilities would need additional energy in the future to meet peaking demands and constructing a pumped storage project to primarily provide ancillary services is a large capital investment with a high level of risk. Additionally, having some level of pumping or generating can help the system respond instantaneously for regulation services.

9.2.5 Scenario 3 Results

Scenario 3 compares how income would change based on forecasted energy prices with CO_2 regulatory costs and energy prices without CO_2 costs. Figures 9-50 and 9-51 show typical week energy prices in 2018 for both price options in June and December, respectively. June and December are shown to show the relative differences in summer and winter months. Prices are less variable during December and most winter months relative to June and other summer months. The difference between prices with CO_2 and without CO_2 is also greater in December relative to June. Negative prices can occur because of increased renewable energy production credits, mostly wind, or the presence of transmission congestion.

Figure 9-50. Typical Week Energy Prices at Trinity in June with and without CO_2 Regulatory Costs

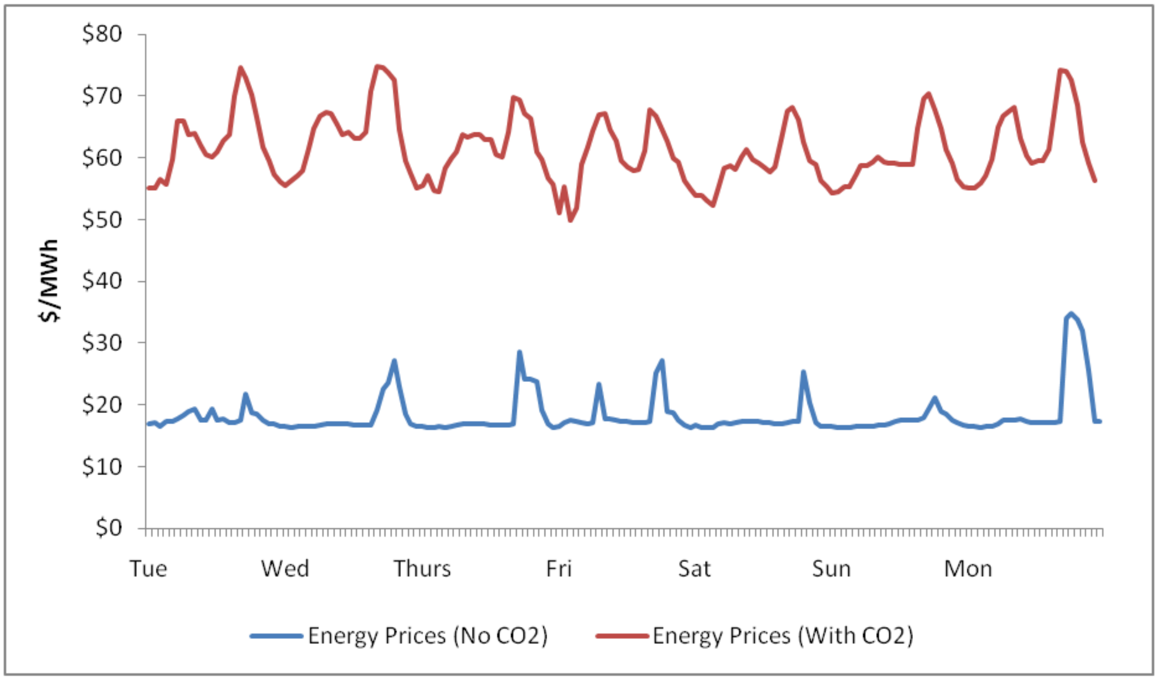


Figure 9-51. Typical Week Energy Prices at Trinity in December with and without CO_2 Regulatory Costs

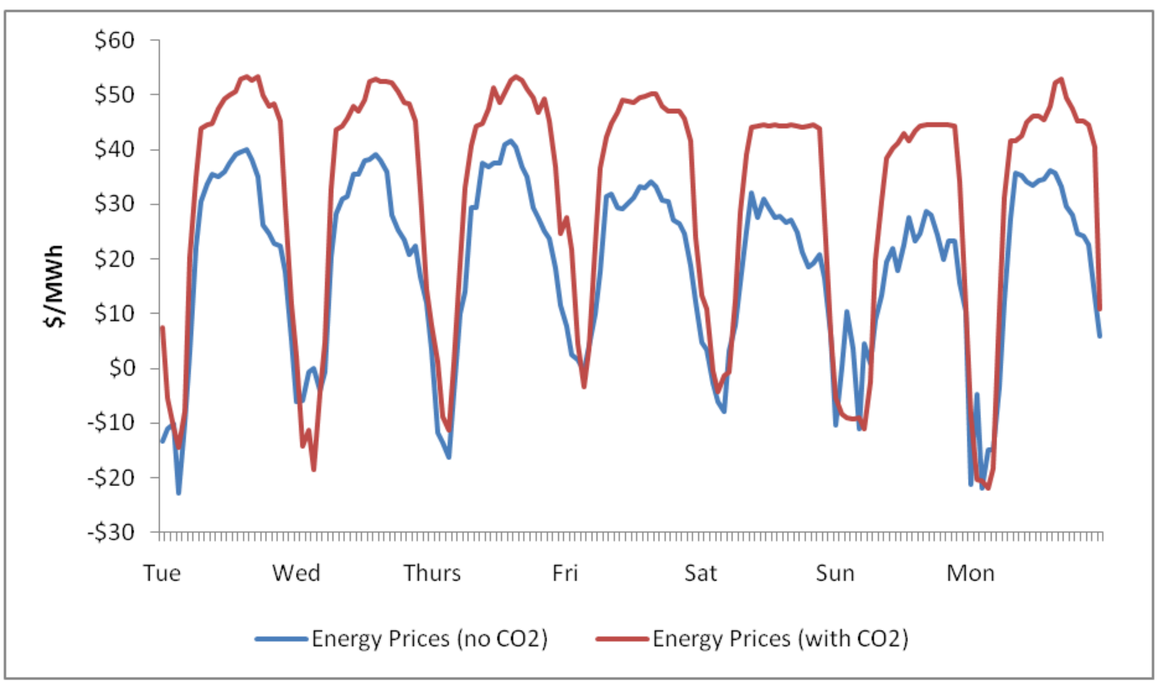
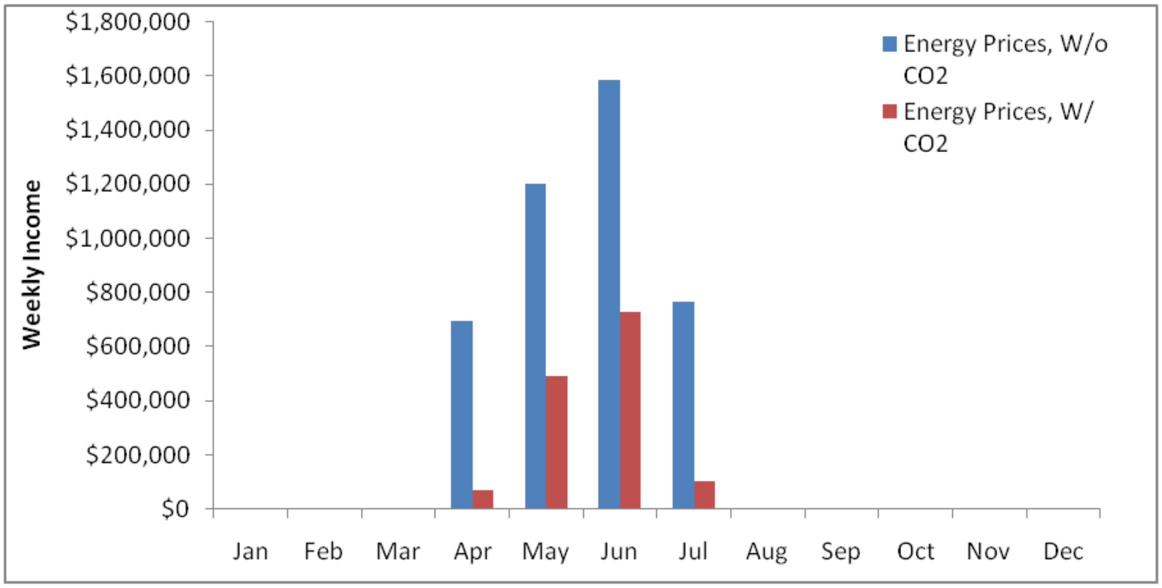


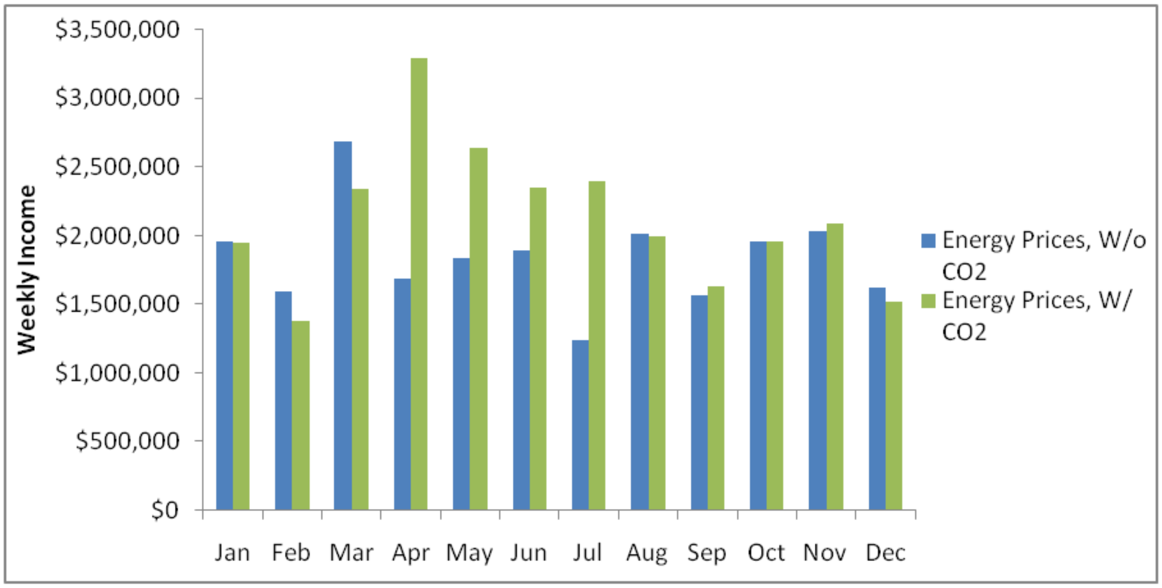
Figure 9-52 shows only arbitrage income (not including ancillary services income) of the base case scenario using with CO_2 prices compared to without CO_2 prices. It can be seen that project operations under the base case with CO_2 prices provides far less income than without CO2 prices in April and July. Therefore, operations for arbitrage or ancillary services were changed during these months to increase income.

Figure 9-52. Arbitrage Income at Trinity with and without CO_2 Regulatory Costs



Using CO_2 energy prices, weekly income would be maximized if the reservoir is operated only for ancillary services in all months but May and June. While arbitrage is profitable in these months, it is less profitable than in the baseline and therefore the amount of the pool dedicated to arbitrage should decrease. The manual optimization sets the arbitrage reservoir pool at 20 percent of total pool volume in May and 30 percent in June (compared to 80 percent and 90 percent, respectively, in the baseline). Figure 9-53 shows total (energy arbitrage and ancillary services) average weekly income under operation scenarios that maximizes income using both energy prices with and without CO_2. Income increases substantially in April and July because the project is operated only for ancillary services, which provides more income than arbitrage. The energy generated for services deployed also provides increased income relative to without CO_2 scenario because the with CO_2 prices are higher. Income increases in May and June, although to a smaller extent than April and July, because the percent of the reservoir pool dedicated to arbitrage is smaller than in the baseline and more of the pool is used for ancillary services.

Figure 9-53. Average Weekly Income at Trinity with and without CO_2 Regulatory Costs



9.2.6 Scenario 4 Results

Scenario 4 tests the sensitivity of income to changes in ancillary service prices. As discussed earlier, forecasts are not available for ancillary service prices, but in general, most experts believe that prices will increase because of increased production of renewable energy resources. Figures 9-54 through 9-57 show average weekly income by month in 2032 for the four ancillary services under each escalation option (described in Section 9.1.5). The escalation options are estimated based on the same proportions of arbitrage and ancillary services in the baseline. Ancillary service income begins to decline from April through July because between 70 and 90 percent of the new reservoir pool is dedicated to energy arbitrage during those months. Income is highest assuming ancillary service price escalation similar to the energy prices with CO_2 escalation rates. As in the base case scenario, regulation up and down services and spin ancillary services would provide the most.

Figure 9-54. Average Weekly Income from Spin Ancillary Services at Trinity

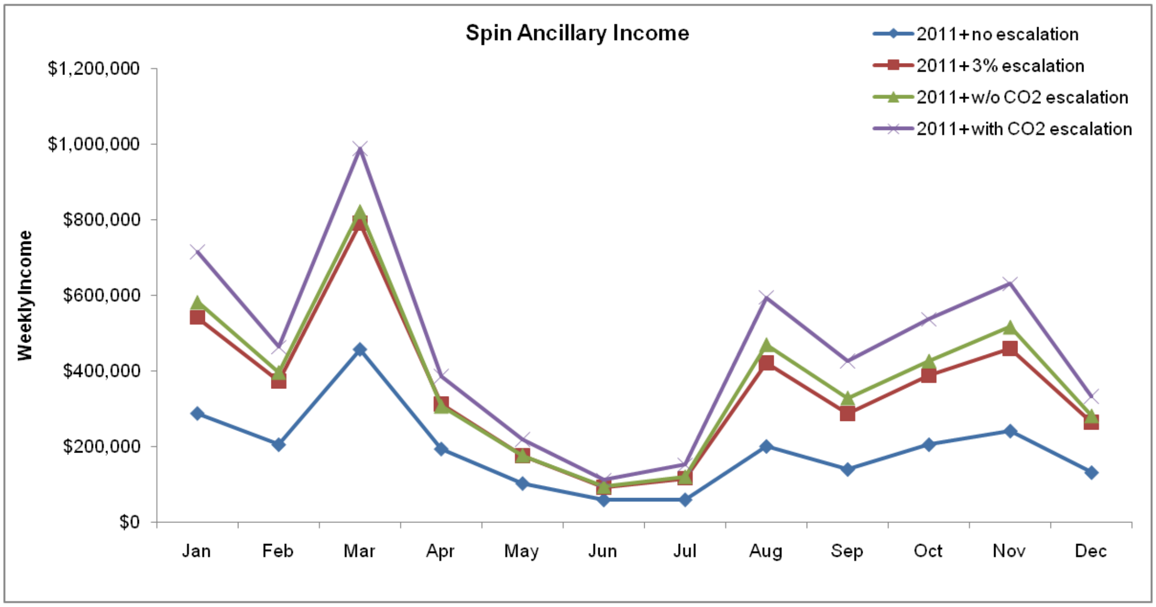


Figure 9-55. Average Weekly Income from Non-Spin Ancillary Services at Trinity

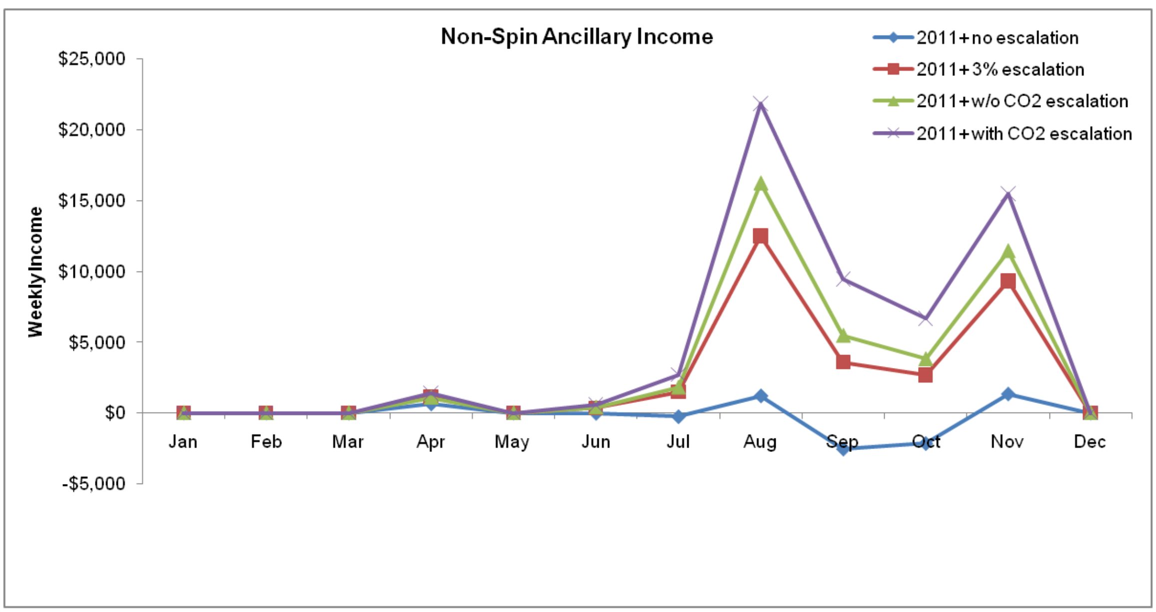


Figure 9-56. Average Weekly Income from Regulation Up Ancillary Services at Trinity

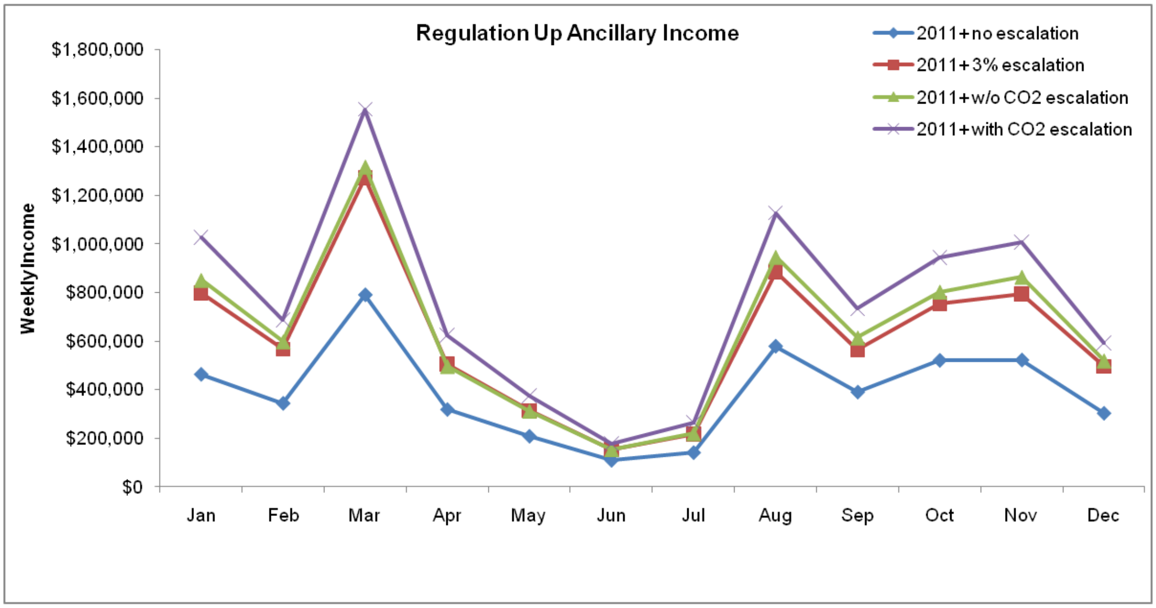


Figure 9-57. Average Weekly Income from Regulation Down Ancillary Services at Trinity

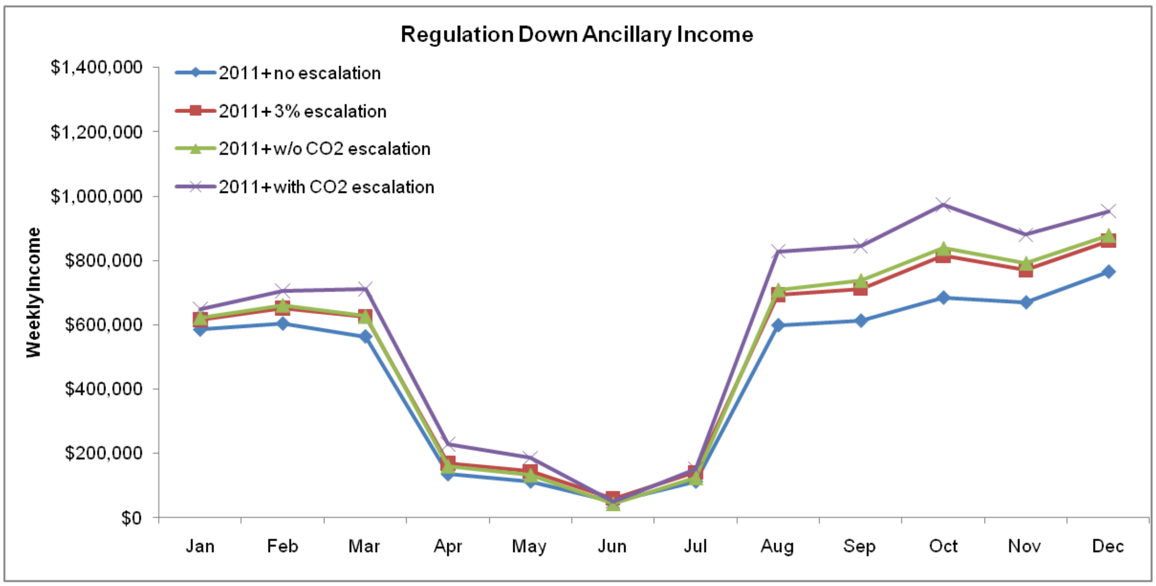
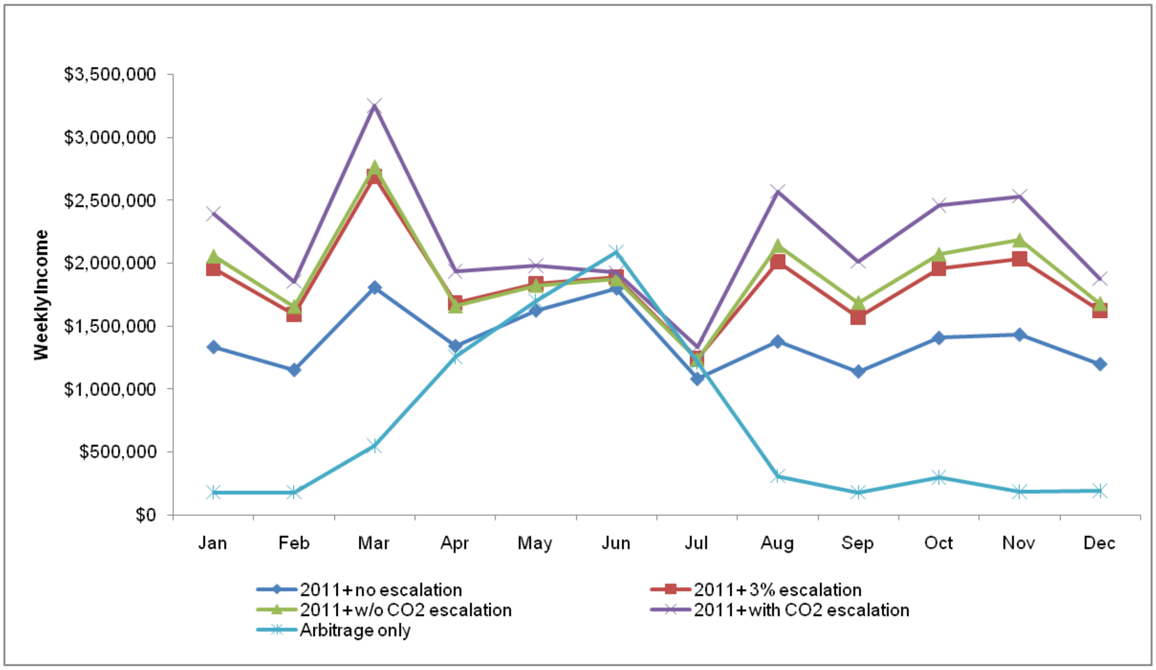


Figure 9-58 shows average weekly total income, which includes energy arbitrage and ancillary services, under the various ancillary service price forecasts. This figure shows that increases in future ancillary service prices relative to no escalation would substantially improve the project's total income. The weekly income for arbitrage only is also shown on Figure 9-58 and highlights how ancillary services add to the income of the project during the non-summer months.

Figure 9-58. Average Weekly Income with Varying Ancillary Service Price Escalation at Trinity



9.2.7 Scenario 5 Results

The objective of Scenario 5 is to assess the impact of climate change in the system's ability to respond to water needs for water and energy generation demands. The most critical measure of impact is the frequency of future use restrictions due to decreased water levels. If precipitation changes due to climate change are significant to the point that water levels in Trinity Reservoir would drop under the bottom of the active conservation pool, future operations would be compromised or restricted. Thus the climate change analysis focuses on determining the likelihood of significant reductions in precipitation in Trinity Reservoir's catchment area and runoff into the lake.

Assuming the same operational objectives (driving operational flows), the most significant impacts related to water level in Trinity Reservoir are evaporation and natural inflows. Evaporation has not been included in any of the scenarios analyzed in this analysis and it is also excluded from the analysis in the climate change scenario, for consistency.

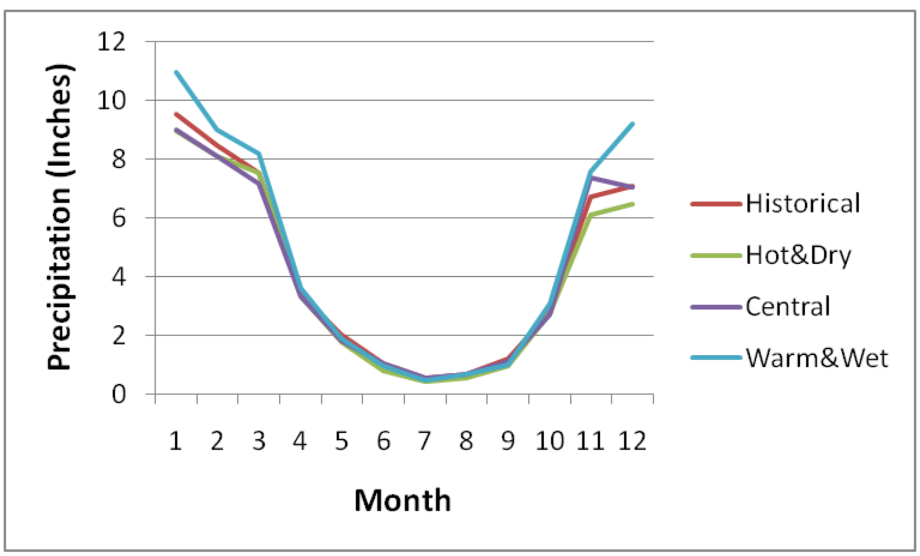
Related to impact on inflows into the lake, the overall approach consisted on obtaining projections of precipitation in the area under climate change conditions and indications of runoff changes as a result. The main two sources of information used in the analysis were the SECURE Water report (SECURE Water Act Section 9503(c) – Reclamation Climate Change and Water 2011) and the databases available in the CREAT developed by EPA. The CREAT (version

2.0) database includes multiple climate model projections providing a distribution of possible future conditions for each specific locations.

Trinity Reservoir is part of the Klamath basin, which is generally projected to experience essentially no changes in precipitation (Reclamation 2011). This includes general area of Trinity Reservoir's catchment where the runoff to the lake generates. The closes sub basin reported in the SECURE Water study (Reclamation 2011) is the Klamath River basin near Klamath, where the mean annual runoff is projected to increase about 4 percent by the 2050s. The mean December-March runoff is projected to increase while the mean April-July runoff is projected to decrease, for a slight net annual increase. Even if this area in the Klamath River basin is relatively close from Trinity Reservoir, additional data for the analysis is recommended as described below.

To provide additional geographic specificity, the CREAT Tool was used to obtain precipitation data for the Trinity Reservoir catchment area. Three groups of predictions were used from models that tend to predict "Hot and Dry" years, "Central" models, and models predicting "Warm and Wet" years. A summary of precipitation by month for each of these three types of predictions for the 2030s was compared to historical data, with results presented in Figure 9-59, which shows a minimal change in precipitation in the Trinity Reservoir area. The annual precipitation historically is 51.1 inches while the precipitation of the three types of climate change projections ranges from 47.7 to 56.7 inches per year.

Figure 9-59. Monthly Precipitation (inches) Comparison for Historical Record vs. Climate Change Projections for the Trinity Reservoir Area



Given the minimal projected impact of climate change in precipitation and runoff for the Trinity Reservoir area, climate change conditions (as predicted by the models used in this analysis) would most likely not have an impact on the pumped storage operations at the Trinity site.

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Chapter 10
Economic Analysis

10.1 Economic Evaluation Methods

The economic evaluation compares the costs and benefits of the proposed pumped storage projects and calculates a benefit-cost ratio under various operating scenarios, as defined in Chapter 9. The economic evaluation estimates benefits and costs over a 50-year period of analysis, from 2018 to 2067. The present value of benefits and costs are calculated using the fiscal year 2013 federal discount rate of 3.75 percent.

The economic evaluation also discusses existing energy market conditions and how the proposed projects would fit into existing market conditions. This analysis includes a discussion of how markets may need to change for a pumped storage project to be more economically viable in the future.

10.1.1 Benefits

Economic benefits are accrued when the pumped storage project sells energy or provides ancillary services. Conceptually, economic benefits are equivalent to the avoided costs of acquiring equivalent energy or ancillary services from another source. Benefits begin to accrue after construction is complete and continue annually until the end of the period of analysis.

The operations model, described in Chapter 9, estimates the amount of energy generated through arbitrage and the level of ancillary services available on an hourly time step for one week. These values are multiplied by hourly market prices for energy and ancillary services to estimate the economic benefits. The calculations occur in the operations model and vary based on a defined operating schedule.

For modeling purposes, the energy prices and ancillary service prices were put into an “average week” format which includes averages of hourly prices for each day of the week for each month (e.g., the average of 1 a.m. prices for all Mondays in January). The result is twelve sets (by month) of hourly prices for one week. The following sections described data sources used for energy and ancillary service prices.

10.1.1.1 Energy Prices

The Northwest Power and Conservation Council (NWPCC) provided hourly wholesale power market price forecasts through 2032 for the following load resource areas: northern California, Montana, Wyoming, and Pacific Northwest (NWPCC 2013). NWPCC uses the AURORA$^{xmp®}$ Electric Market Model to forecast wholesale power prices, based on expected generation costs. The forecasts incorporate assumptions regarding load growth, future fuel prices, new resource costs, capacity reserve requirements, climate control regulation and renewable portfolio standard resource development into its forecasts of future wholesale power prices (NWPCC 2010). The three factors that most influence power prices include the future price of natural gas, the future cost of carbon dioxide (CO_2) production, and renewable resource development associated with Renewable Portfolio Standards (NWPCC 2010).

NWPCC runs various price forecast scenarios because of the uncertainty in these variables. The two cases provided for this analysis include the prices with and without an assumed federal CO_2 regulatory cost. The CO_2 regulatory cost represents additional costs to comply with future greenhouse gas emission constraints; therefore, the set of energy prices with the CO_2 cost is higher than the prices without it. In both data sets, the projected wholesale energy prices increase in real terms at a rate above inflation. Both data sets represent the medium forecast of natural gas prices from AURORA$^{xmp®.}$

The economic analysis calculates benefits for the 2018-2067 period of analysis, but the AURORA$^{xmp®}$ price set ends in 2032. This analysis assumes that the hourly 2032 forecast prices remain constant through 2067. All prices were adjusted from 2006 to 2012 dollars using the AURORA$^{xmp®}$ general inflation index. The operations model allows the user to select among the four load resource areas for both energy sales and usage.

10.1.1.2 Ancillary Service Prices

Ancillary service prices were collected from California Independent System Operator (CAISO) Open Access Same-Time Information System (OASIS). OASIS provides hourly market prices for regulation up, regulation down, spinning reserves, and non-spinning reserves in both the day-ahead and real-time markets. The day-ahead market prices are used for this analysis.

The operations model includes the hourly ancillary service prices for 2011 and 2012. The 2011 prices were relative higher than previous years, mostly due to very high runoff conditions in the first half of the year. This decreased the availability of ancillary services from hydropower resources as they provided energy instead of ancillary services (CAISO 2012). The 2012 average day-ahead prices decreased from 2011. The decrease was likely due to relatively low natural gas costs and an increase in provision of spinning reserves from hydropower resources compared to 2011 (CAISO 2013).

Because of the variability in price factors and the relatively short-term existence of the ancillary service market, ancillary service price forecasts are not readily available. The operations model includes various options for ancillary service price escalation, as described in Chapter 9.

There is no ancillary service market in Wyoming or Montana. The analysis uses the CAISO prices for the ancillary service prices for the Yellowtail and Seminoe sites because it is the best available data at this time.

10.1.2 Costs

The economic analysis considers costs for construction, transmission upgrades, O&M, replacement costs, and pumping energy over the 50-year period of analysis. Chapter 8 presents these cost estimates of the proposed projects. The economic analysis assumes that construction would begin in 2018 and require 3 years to complete. After construction is complete, O&M costs would occur annually. O&M costs include annual FERC fees, labor, contracts, consumables, inventory, and other routine operation and maintenance activities. Major maintenance, or replacement, would occur in year 20. The replacement cost is assumed to be $1.5 million per unit.

Energy costs for pumping are considered separately from O&M costs and would vary based on the operating schedule. The operations model provides pumping costs for each of the proposed scenarios. Pumping costs are based on the NWPCC forecast energy prices, described above.

The construction cost estimates include necessary transmission infrastructure upgrades. Chapter 7 includes transmission studies for each site that evaluates various options for transmission upgrades and estimates potential costs.

10.1.3 Benefit-Cost Ratio

The economic analysis calculates a benefit-cost ratio and net benefits (or costs) for each of the proposed projects. The benefit-cost ratio compares the present value of benefits to costs over the 50-year period, using the 2013 federal discount rate of 3.75 percent. A benefit-cost ratio greater than 1.0 indicates that the project could be economically viable and may warrant further study. Net benefits (or costs) are calculated as revenues minus costs.

The model calculates benefits for each year of the 50 year period, starting after construction. The benefits are based on the energy price and ancillary service price forecasts for each year in the 50 year period. The operations schedule is assumed to be the same for each year.

The benefit-cost ratio is calculated for the base case and scenarios 3and 4. The base case scenario is a manual optimization of the hourly generating-pumping schedule and arbitrage/ancillary service volume to maximize revenues, considering that some level of energy arbitrage and ancillary services are desirable. Scenarios 3 and 4 consider changes in energy prices and ancillary service prices, which were shown to affect project revenues in the operations analysis.

Scenario 1 is not included in the economic analysis because it compares wet and dry year hydrologic conditions and shows that the changes in revenue under wet and dry years would be minor. Similarly, Scenario 5 evaluates how climate change could affect project operations and determines effects would also be minor.

The operating results for Scenario 2 showed that revenues are sensitive to the size of the ancillary service and arbitrage pools; and, generally, ancillary services would be more profitable than arbitrage in most months. Scenario 3 generally captures the effects of changes in the arbitrage and ancillary services pool as the “optimized” operations for using with CO_2 prices includes only ancillary services in all months except June.

10.1.4 Market Conditions Analysis

Reclamation has indicated that the primary objective for the proposed pumped storage projects would be to market ancillary services; selling arbitrage energy would be a secondary objective. The operations model results support this objective showing that providing ancillary services would be the more profitable operation relative to energy arbitrage. The base case scenarios for each site typically include little arbitrage only when energy prices support the operation.

Given that the projects would target marketing ancillary services, it is important for them to be in areas with high development of renewable resources, which require energy storage. Much analysis has been completed on wind energy potential throughout the nation. In 2005, the BLM approved a Record of Decision for the Wind Energy Development Program to support development of wind energy resources on BLM-administered lands in 11 western states, including California, Montana, and Wyoming. The decision established policies and BMPs for the administration of wind energy development activities and established minimum requirements for mitigation measures.

Areas with developed ancillary services markets, such as California, would also support the project benefits. Transmission is also an important factor to consider when evaluating the benefits of a pumped storage project. The projects must be connected to load centers where electricity is in demand and would be consumed. Chapter 7 provides a transmission limits analysis and identify some major infrastructure requirements for each of the proposed sites. This analysis considers each of these factors to evaluate how the proposed pumped storage projects could fit into existing markets.

10.2 Yellowtail Economic Evaluation

This section presents the economic results for the proposed Yellowtail pumped storage project. The operations model, described in Chapter 9, provides estimates of economic benefits, which are compared to the costs presented in Chapter 8. Benefits vary relative to the different operating scenarios, but costs would be the same for all scenarios. Table 10-1 summarizes the capital, annual, and replacement costs for the Yellowtail project. The largest capital cost components would be the powerplant equipment ($697 million), power station ($199.2 million), dam ($134.7 million), and transmission upgrades ($122.5 million). Table 8-1 includes complete cost estimates.

Table 10-1. Yellowtail Project Costs (Million $, 2012 $)

Total Construction Cost	$2,286.1
Annual O&M Cost	$14.0
Replacement Costs (every 20 years)	$6.0
Installed Cost $ per MW	$1.3

10.2.1 Base Case and Scenario Results

The economic analysis calculates a benefit-cost ratio for the operations under the base case and Scenarios 3 and 4. Scenarios 3 and 4 test the sensitivity of revenues to changes in energy prices or ancillary service prices. Table 10-2 summarizes arbitrage and ancillary service benefits and the benefit-cost comparison. The benefits under the base case and each scenario are compared to the Yellowtail project's capital, replacement, and annual costs described above.

Table 10-2. Yellowtail Project Benefit Cost Summary, Present Value, 3.75% discount rate, 50 years, Million $

	Base Case	Scenario 3	Scenario 4		
	Energy Prices (w/o CO2) Ancillary Price (2011 prices + 3% escalation)	Energy Prices (with CO2) Ancillary Price 2011 prices + 3% escalation	Energy Prices (w/o CO2) Ancillary Price- 2011 prices (no escalation)	Energy Prices (w/o CO2) Ancillary Price- 2011 prices + w/o CO2 price escalation	Energy Prices (w/o CO2) Ancillary Price- 2011 prices + with CO2 price escalation
Present Value Costs	$2,402.39	$2,402.39	$2,402.39	$2,402.39	$2,402.39
Present Value Benefits	$2,216.41	$2,323.69	$1,606.73	$2,293.72	$3,109.09
Net Benefits/(Costs)	($185.98)	($78.70)	($795.66)	($108.67)	$706.70
Benefit/Cost Ratio	0.92	0.97	0.67	0.95	1.29
Annualized Costs	$107.08	$107.08	$107.08	$107.08	$107.08
Annualized Benefits	$98.79	$103.58	$71.62	$102.24	$138.59

Table 10-2 shows that the Yellowtail site would not have positive net benefits under the base case scenario. The only modeled pricing structure that yields potential positive net benefit would be if ancillary services escalated similar to energy price with CO2 regulatory costs.

This pricing structure is at the high end of the range of forecasted ancillary service prices. Ancillary service prices would need to escalate up to 34 percent from 2011 prices for this scenario to occur. .

In general, the flat nature of energy prices during the winter months reduces the net benefits from serving ancillary service calls. This mostly occurs because the additional pumping costs required to refill the ancillary service pools negates the generating income. There may be some opportunity to shift some pumping and generating hours to increase income under the base case scenario; or the entire project could be operated for ancillary services during all months.

10.2.2 Market Conditions Analysis

Montana has been identified as a state with high wind energy potential. The U.S. Department of Energy (DOE) developed the Wind Program to accurately define, measure, and forecast the nation's land-based and offshore wind resources. The Energy Department, the National Renewable Energy Laboratory, and AWS Truepower developed a wind resources map that shows wind resources estimated at an 80-m height for all 50 states and offshore resources up to 50 nautical miles from shore (available at: http://www.windpoweringamerica.gov/wind_maps.asp). Table 10-3 summarizes the wind energy potential estimated in Montana and the U.S. Montana ranked 3rd of the 50 states in regards to total installed capacity. Montana would provide a suitable market for a pumped storage project to provide bulk energy storage for wind integration.

Table 10-3. Windy Land Area >= 30% Gross Capacity Factor at 80m and Wind Energy Potential in Montana

	Windy Land Area >= 30% Gross Capacity Factor at 80m					Wind Energy Potential	
State	Total (km^2)	Excluded[1] (km^2)	Available (km^2)	Available % of State	% of Total Windy Land Excluded	Installed Capacity (MW)	Annual Generation (GWh)
Montana	232,768.6	43,967.7	188,800.9	49.60%	18.9%	944,004.4	3,228,620
U.S. Total	2,988,328	796,945	2,191,382	22.36%	26.7%	10,956,912	38,552,706

[1] Excluded lands include protected lands (national parks, wilderness, etc.), incompatible land use (urban, airport, wetland, and water features), and other considerations.
Source: NREL and AWS Truepower 2010

Montana has an RPS that requires public utilities and electricity suppliers serving 50 or more customers to obtain 15 percent of their retail electricity sales from eligible renewable resources by 2015. In 2011, electricity suppliers provided 10 percent of retail sales from renewable resources, which was compliant with the interim 2011 RPS target of 10 percent (Montana Public Service Commission 2012). Montana is increasing renewable energy development to meet the RPS for 2015. As of January 2011, Montana's wind power capacity is 386 MW. Montana is projected to add 5000 MW of wind generated electricity through the future development of over 50 proposed wind projects.

Northwestern Energy serves approximately 340,000 customers in Montana. The service area covers approximately 73 percent of Montana (Northwestern Energy 2013). The 2012 peak demand was 1,784 MW and the average daily load was 1,237 MW (Northwestern Energy 2013). In the 2011 Electric Supply Resource Planning and Procurement Plan, Northwestern Energy identified the need to meet Montana RPS statutes, add new electric supply resources to the portfolio, and monitor regional energy markets including ancillary service markets (Northwestern 2012). Northwestern Energy acquired nearly 90 MW of new wind power, including purchase of the 40 MW Spion Kop wind farm. With these additions, Northwestern Energy is positioned to meet RPS through 2016 (Northwestern 2012). Northwestern Energy is currently working to understand the impact of additional wind power on the reliability of the interconnected electric system. A Montana Wind Integration Study was completed in 2011 that evaluated various wind development scenarios and regulating reserve requirements. The modeling generally showed the need for over 100 MW of regulating reserve requirements to support Northwestern's existing and potential wind power capacity (Northwestern 2011).

Transmission is another issue that could affect the marketability of a pumped storage project. The Yellowtail site is in a rural area of Montana and would require 60 miles of transmission lines to connect to Northwestern Energy's Broadview substation, which is part of the 500 kV Colstrip corridor transmission system. From Broadview, electricity could potentially be transmitted to areas of the Pacific Northwest, including Idaho and Washington. Northwestern Energy initially proposed the Mountain States Transmission Intertie Project to allow for new wind energy sources produced in Montana to be transmitted throughout the western grid. The project is currently on hold due to market uncertainty and permitting issues; however, Northwestern Energy continues to monitor conditions and believes that a new transmission facility will be required in the future to allow development of wind resources (Northwestern Energy 2013).

In conclusion, while Montana does have an RPS, it is being met by proactive policies of Northwestern Energy, the major public utility in the state. There is no developed ancillary services market in the state, which makes it difficult to support a large capital investment for pumped storage. Montana also does not have the urban demand centers that would justify a pumped storage project the scale of Yellowtail. Substantial investment would need to be realized in transmission facilities in order to market arbitrage and ancillary services to load centers in the Northwest power markets.

10.3 Seminoe Economic Evaluation

Table 10-4 summarizes the capital, annual, and replacement costs for the Seminoe projects. The largest capital cost components for all projects would be the powerplant equipment, power station, and the dam. The powerplant equipment for Seminoe 5A3 would be substantially higher than the other two sites, which makes it the most expensive site. 5A2 is the only Seminoe site that requires a surge chamber, which would add to total cost for that site. Table 8-1 includes complete cost estimates.

Table 10-4. Seminoe Projects Costs (Million $, 2012 $)

	5A	5A3	5C
Total Construction Cost	$1,924.2	$1,889.7	$1,306.3
Annual O&M Cost	$9.0	$10.8	$7.0
Replacement Costs (every 20 years)	$6.0	$6.0	$3.0
Installed Cost $ per MW	$2.2	$1.7	$2.3

10.3.1 Base Case and Scenario Results

Table 10-5 summarizes arbitrage and ancillary service benefits and the benefit-cost comparison for the three Seminoe sites. The benefits under the base case for the three sites are compared to the capital, replacement, and annual costs described above. All sites have a benefit-cost ratio well below 1.0. Seminoe 5A3 has the highest benefit-cost ratio of the three sites and was furthered evaluated for changes in energy or ancillary services prices.

Table 10-5. Seminoe 5A2, 5A3, and 5C Base Case Benefit Cost Summary, Present Value, 3.75% discount rate, 50 years, Million $

	Seminoe 5A2	Seminoe 5A3	Seminoe 5C
	Energy Prices (w/o CO2) Ancillary Price (2011 prices + 3% escalation)	Energy Prices (w/o CO2) Ancillary Price (2011 prices + 3% escalation)	Energy Prices (w/o CO2) Ancillary Price (2011 prices + 3% escalation)
Present Value Costs	$1,935.7	$2,002.20	$1,354.2
Present Value Benefits	$667.3	$1,174.46	$557.4
Net Benefits/(Costs)	($1,268.4)	($827.74)	($796.8)
Benefit/Cost Ratio	0.34	0.59	0.41
Annualized Costs	$86.3	$89.25	$60.4
Annualized Benefits	$29.7	$52.35	$24.8

Table 10-6 summarizes arbitrage and ancillary service benefits and the benefit-cost comparison of the scenarios for Seminoe 5A3.

Table 10-6. Seminoe 5A3 Benefit Cost Summary, Present Value, 3.75% discount rate, 50 years, Million $

	Base Case	Scenario 3	Scenario 4		
	Energy Prices (w/o CO2) Ancillary Price (2011 prices + 3% escalation)	Energy Prices (with CO2) Ancillary Price 2011 prices + 3% escalation	Energy Prices (w/o CO2) Ancillary Price- 2011 prices (no escalation)	Energy Prices (w/o CO2) Ancillary Price- 2011 prices + w/o CO2 price escalation	Energy Prices (with CO2) Ancillary Price- 2011 prices + with CO2 price escalation
Present Value Costs	$2,002.20	$2,002.20	$2,002.20	$2,002.20	$2,002.20
Present Value Benefits	$1,174.46	$1,413.82	$745.67	$1,210.51	$1,529.56
Net Benefits/(Costs)	($827.74)	($588.38)	($1,256.53)	($791.69)	($472.64)
Benefit/Cost Ratio	0.59	0.71	0.37	0.60	0.76
Annualized Costs	$89.25	$89.25	$89.25	$89.25	$89.25
Annualized Benefits	$52.35	$63.02	$33.24	$53.96	$68.18

Table 10-6 shows that the Seminoe site would not have positive net benefits under any of the modeled pricing structures. Benefits would need to increase by about 40 percent or costs would need to decrease by about 40 percent for the project to be economically viable. The pricing structure that yields the most benefits uses energy prices with CO_2 and ancillary service prices increasing at a rate similar to the with-CO_2 energy prices. The benefit cost ratio would be 0.76. Even if the project operations could be further optimized to generate additional revenues, it is not likely that the site would become economically viable and have a benefit-cost ratio greater than 1.0.

10.3.2 Market Conditions Analysis

Wyoming is a state with high potential to develop wind energy. Table 10-7 summarizes the wind energy potential estimated in Wyoming and the U.S. While Wyoming has a high potential for wind energy development, the lack of high population centers and transmission capacity are factors that may limit development. Wyoming ranked 8th of the 50 states in regards to total installed capacity.

Table 10-7. Windy Land Area >= 30% Gross Capacity Factor at 80m and Wind Energy Potential in Wyoming

	Windy Land Area >= 30% Gross Capacity Factor at 80m					Wind Energy Potential	
State	Total (km^2)	Excluded[1] (km^2)	Available (km^2)	Available % of State	% of Total Windy Land Excluded	Installed Capacity (MW)	Annual Generation (GWh)
Wyoming	146,166.2	35,751.7	110,414.5	43.58%	24.5%	552,072.6	1,944,340
U.S. Total	2,988,328	796,945	2,191,382	22.36%	26.7%	10,956,912	38,552,706

[1] Excluded lands include protected lands (national parks, wilderness, etc.), incompatible land use (urban, airport, wetland, and water features), and other considerations.
Source: NREL and AWS Truepower 2010

As of the end of 2012, Wyoming had 645 MW of installed wind energy capacity (NREL 2013). Wyoming does not have a RPS, there is substantial renewable energy production from wind, solar, and geothermal resources. In 2009, the BLM established the Wyoming Renewable Energy Coordination Office to facilitate development of renewable energy projects on BLM-administered public lands in Wyoming. Wyoming is also the location of the proposed Chokecherry and Sierra Madre Wind Energy Project, which could include up to 1,000 wind turbines with a capacity of 2,000 to 3,000 MW, making it the largest wind farm in North America (BLM 2012).

The Seminoe pumped storage sites would have transmission lines connected to the Aeolus substation, which will connect to the Gateway West Transmission Line. When the Gateway West line is complete, the Seminoe sites could be connected to Idaho Power and Rocky Mountain Power.

Idaho Power is a major utility serving Idaho and part of the Pacific Northwest. The number of customers in Idaho Power's service area is expected to increase from approximately 492,000 in 2010 to over 650,000 by the end of the planning period in 2030. Even with the recent recession, population growth in Idaho Power's service area will require the company to add physical resources to meet the energy demands of its growing customer base (Idaho Power 2011). The median or peak-hour load forecast predicts peak-hour load will grow from 3,334 MW in 2011 to 4,643 MW in 2030. Median average monthly energy use is forecasted to increase from 1,189 MW in 2011 to 2,362 MW in 2030 (Idaho Power 2011). Idaho Power has 678 MW of installed wind generation capacity, and has recognized the need for additional balancing reserves to increase the effectiveness of existing and future wind power (Idaho Power 2013).

Rocky Mountain Power serves areas in Wyoming, Utah (including Salt Lake City), and eastern Idaho. Rocky Mountain Power is a part of PacifiCorp, which also serves areas in the Pacific Northwest. Rocky Mountain Power operates a number of existing wind generation systems, primarily in Wyoming, and PacifiCorp has additional facilities in the Pacific Northwest. PacifiCorp's 2013 Integrated Resource Plan identified the need for additional balancing reserves to integrate wind power into the overall generation portfolio (PacifiCorp 2013).

In conclusion, Wyoming is a state with substantial wind generation potential. For the potential to be developed, major increases in bulk storage for load management would be required in the future. However, Wyoming currently does not have an established ancillary services market, which is a significant challenge to implementing a large-scale energy storage project. Wyoming does not have the population base to support a large scale increase in power production. Therefore, increases in new electrical capacity, over and above load growth, would need major increases in transmission capacity to load centers in the Northwest and Southwest.

10.4 Trinity Economic Evaluation

Table 10-8 summarizes the capital, annual, and replacement costs for the Trinity project. The largest capital cost components would be the powerplant equipment ($545.0 million), power station ($225.4 million), horizontal power tunnel ($144.0 million), tailrace tunnels ($109.2 million) and transmission upgrades ($70.6 million). This site would also require a surge chamber ($98.6 million). Table 8-1 includes complete cost estimates.

Table 10-8. Trinity Project Costs (Million $, 2012 $)

Total Construction Cost	$2,266.6
Annual O&M Cost	$10.3
Replacement Costs (every 20 years)	$6.0
Installed Cost $ per MW	$2.2

The present value of total costs over the 50 year period, using a 3.75 percent discount rate would be $2,310.6 million. Annualized costs over the 50 year period would be about $103.0 million.

10.4.1 Base Case and Scenario Results

Table 10-9 summarizes arbitrage and ancillary service benefits and the benefit-cost comparison. The benefits under the base case and each scenario are compared to the Yellowtail project's capital, replacement, and annual costs described above.

Table 10-9. Trinity Project Benefit Cost Summary, Present Value, 3.75% discount rate, 50 years, Million $

	Base Case	Scenario 3	Scenario 4		
	Energy Prices (w/o CO2) Ancillary Price (2011 prices + 3% escalation)	Energy Prices (with CO2) Ancillary Price 2011 prices + 3% escalation	Energy Prices (w/o CO2) Ancillary Price- 2011 prices (no escalation)	Energy Prices (w/o CO2) Ancillary Price- 2011 prices + w/o CO2 price escalation	Energy Prices (w/o CO2) Ancillary Price- 2011 prices + with CO2 price escalation
Present Value Costs	$2,310.6	$2,310.6	$2,310.6	$2,310.6	$2,310.6
Present Value Benefits	$1,672.3	$1,927.2	$1,312.0	$1,735.2	$1,990.4
Net Benefits/(Costs)	($638.3)	($383.4)	($998.6)	($575.4)	($320.2)
Benefit/Cost Ratio	0.72	0.83	0.57	0.75	0.86
Annualized Costs	$103.0	$103.0	$103.0	$103.0	$103.0
Annualized Benefits	$74.5	$85.9	$58.5	$77.3	$88.7

Table 10-9 shows that the Trinity site would not have positive net benefits under any of the modeled pricing structures. For most of the scenarios, benefits would need to increase by 30 percent or costs would need to decrease by 30 percent for the project to be economically viable. The pricing structure that yields the most benefits would occur if ancillary service prices increased at a rate similar to the with-CO_2 energy prices. The benefit cost ratio would be 0.86. Even if the project operations could be further optimized to generate additional revenues, it is not likely that the site would become economically viable and have a benefit-cost ratio greater than 1.0.

Scenario 3 compares an optimized pump-generation schedule using energy prices without CO_2 to and optimized schedule using prices with CO_2. The operations for the with-CO_2 scenario include all ancillary services in all months, except June, which includes some energy arbitrage. Even with an operation focusing on providing ancillary services, project benefits would still be less than costs. Therefore, using the reservoir for only the higher valued ancillary services would not necessarily mean the project would be economically viable.

10.4.2 Market Conditions Analysis

Table 10-10 summarizes the wind energy potential estimated in California and the U.S. California ranked 20th of the 50 states in regards to total installed capacity.

Table 10-10. Windy Land Area >= 30% Gross Capacity Factor at 80m and Wind Energy Potential in California

	Windy Land Area >= 30% Gross Capacity Factor at 80m					Wind Energy Potential	
State	Total (km^2)	Excluded[1] (km^2)	Available (km^2)	Available % of State	% of Total Windy Land Excluded	Installed Capacity (MW)	Annual Generation (GWh)
California	26,901.3	20,079.2	6,822.0	1.67%	74.6%	34,110.2	105,646
U.S. Total	2,988,328	796,945	2,191,382	22.36%	26.7%	10,956,912	38,552,706

[1] Excluded lands include protected lands (national parks, wilderness, etc.), incompatible land use (urban, airport, wetland, and water features), and other considerations.
Source: NREL and AWS Truepower 2010

As of the end of 2012, California had 5,549 MW of installed wind energy capacity (NREL 2013). California's RPS requires electric utilities to have 33 percent of their retail sales derived from eligible renewable energy resources in 2020 and all subsequent years. In 2012, California's three largest investor-owned utilities (Pacific Gas and Electric, San Diego Gas and Electric, and Southern California Edison) had served 19.8 percent of their retail electricity sales with renewable power (California Public Utilities Commission 2013).

The Trinity pumped storage project would be connected to the Olinda substation, which is connected to the California-Oregon Intertie. The transmission system would connect the project to the Pacific Northwest, central California, and southern California, which represent large demand centers that could use energy generated from the Trinity site. The California-Oregon Intertie experiences congestion due to high imports; therefore, significant transmission upgrades may be necessary to integrate such a large capacity pumped storage project.

A key differentiator in California relative to Montana and Wyoming is the existence of an ancillary services market. CAISO procures four ancillary services (regulation up, regulation down, spinning reserves, and non-spinning reserves) in the day-ahead and real-time markets. System-wide requirements are set for each ancillary service to meet or exceed minimum operating reliability criteria and control performance standards. The day-ahead requirement is set equal to 100 percent of the estimated requirement, so that most ancillary services are procured in the day-ahead market (day-ahead prices were used in the operations model). Procurement of ancillary services increased in 2012 relative to 2011. Average hourly procurement of regulation down increased 2 percent to 350 MW in 2012. Procurement of regulation up resources decreased 6 percent to 333 MW. Spinning reserve procurement increased 4 percent to 887 MW and non-spinning reserve procurement increased 1 percent to 848 MW. CAISO expects that ancillary service procurement will continue to increase with future increases in renewable energy resources to meet the California RPS (CAISO 2013).

In conclusion, the existence of an ancillary services market supports the potential for a pumped storage project to support renewable energy integration, more so than in Montana and Wyoming. The Trinity site would be connected to the California-Oregon Intertie, and electricity can be transmitted to vary large demand areas. However, some significant transmission upgrades may be needed to accommodate the project.

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Chapter 11 Environmental Evaluation

This section summarizes potential environmental effects of the proposed project and potential permits required prior to construction. Environmental impacts and permitting needs will be further evaluated during future environmental compliance.

11.1 Yellowtail Site

11.1.1 Potential Environmental Effects

11.1.1.1 Fisheries

The construction of Yellowtail Dam on the Bighorn River created a high quality trout fishery below the dam. Rainbow and Brown trout attract anglers from all over the country and the Bighorn River below the dam is one of the most fished rivers in Montana (NPS 2013a). Bighorn Lake supports a wide variety of game fish, including Shovelnose Sturgeon, Smallmouth Bass, Yellow Perch, and Walleye. Table 11-1 below presents a list of common fish species in Bighorn Lake and in the Bighorn River.

Temporary construction-related impacts to fish in Bighorn Lake would include increased turbidity from in-water work for the tunnels and intake. These effects would be reduced (but not fully avoided) by implementation of Best Management Practices (BMPs).

Long-term impacts to fish could occur from entrainment at the new intake that would allow water to be conveyed from the existing Bighorn Lake into the new reservoir, but effects would be minimized by incorporating a fish screen in the intake design.

The proposed volume of water that would be pumped into the new reservoir would be very small relative to the volume of water in the existing Bighorn Lake and would therefore be unlikely to change reservoir elevations such that there would be adverse effects to existing fish in the lake. While water would be pumped between the new reservoir and Bighorn Lake, there would be no net change in overall storage in Bighorn Lake. Therefore, releases from Bighorn Lake would not change and would meet all downstream flow requirements for fish. This project would not have any substantial impacts to the coldwater pool, or downstream temperatures that could affect fish.

Table 11-1. Bighorn Lake and River Fish Species

Fish Species	Bighorn Lake	Bighorn River	Tributary to Bighorn River
Trout Species:			
Cutthroat Trout	X	X	
Yellowstone cutthroat	X	X	
Rainbow Trout	X	X	
Brown Trout			X
Lake Trout	X	X	
Other Species:			
Paddlefish		X	
Goldeye		X	
Sockeye Salmon or kokanee	X	X	
Mountain Whitefish	X	X	
Northern Pike		X	
Lake chub	X	X	
Carp	X	X	
Silvery minnow	X*	X*	
Plains minnow	X*	X*	
Sturgeon chub	X*	X*	
Shovelnose sturgeon	X	X	
Flathead chub	X	X	
Golden shiner	X	X	
Fathead minnow	X	X	
Longnose dace	X	X	
River carpsucker	X	X	
Longnose sucker	X	X	
White sucker	X	X	
Mountain sucker	X		
Shorthead redhorse	X		
Black bullhead	X		
Channel catfish	X	X	
Stonecat	X	X	
Burbot or ling	X	X	
Plains killifish	X*	X*	
Green sunfish	X	X	
Bluegill	X	X	
Largemouth bass	X		
Black crappie	X	X*	
Yellow perch	X	X	
Sauger	X	X	
Walleye	X	X	

*Possibly present
Source: NPS 2013a

11.1.1.2 Vegetation and Wildlife

The Bighorn Lake area contains a wide variety of vegetation and wildlife. Over 261 species of birds have been identified in the Bighorn Canyon National Recreation Area (NRA), including peregrine falcons, raptors, turkey vultures, rough-legged hawks, Golden eagles, American kestrels, Great Horned owls and Prairie falcons. Song birds, such as song sparrows, tree sparrows, yellow throats, yellow warblers, lazuli buntings, mountain bluebirds, northern orioles, wrens, meadowlarks, blackbirds, lark buntings, and robins are also common (NPS 2013a).

Larger mammals that are known to be present in the NRA include elk, bighorn sheep, mule deer, and black bears. The Crow Reservation directly adjacent to the Bighorn Canyon NRA contains a large herd of bison that can be seen from some park roads. Approximately 10 miles southwest of the proposed Yellowtail site is the Pryor Mountain wild horse range (NPS 2013a).

Bighorn Canyon has a wide variety of plants because of the differences in elevation and climate. The southern area contains desert plants such as Utah juniper and sagebrush as this area receives the least amount of moisture. In the Rocky Mountains, there are a large variety of plants from shrubland on the lower mountain slopes to forested areas at higher elevations. In the northern areas around Fort Smith, plants include prairie grasses and wildflowers (NPS 2013a).

Special-status species in Big Horn County, Montana and the Crow Reservation include the Black-footed ferret, which is listed as endangered under the Federal Endangered Species Act, as well as the Greater Sage-Grouse and Sprague's Pipit, which are both listed as Candidate species (USFWS 2013a; 2013b). There is no critical habitat in Big Horn County.

Temporary construction-related impacts on vegetation and wildlife from this project would include removal of vegetation for construction and staging, as well as dust, noise, and vibration impacts. Use of equipment and vehicles would have the potential to physically damage existing wildlife and habitat. There may also be impacts to special-status species and their habitat.

There would be permanent loss of vegetation for construction of the new access road, dam, reservoir, and associated pump-generation facilities. An area currently containing vegetation would be permanently submerged under water once the new reservoir is filled and could inundate existing wildlife habitat. The new reservoir would create new aquatic habitat. The presence of a new road that would be used for routine maintenance could harm wildlife and would have noise, dust, and vibration impacts. The new reservoir and other associated facilities have the potential to fragment wildlife habitat or corridors.

11.1.1.3 Surface Water Resources

Bighorn River is approximately 461 miles long and is a tributary to the Yellowstone River. It begins in Wyoming, just south of the Owl Creek Mountains and flows north through central Wyoming and into Montana towards the Yellowtail Dam. After Yellowtail Dam, the Bighorn River flows into the Yellowstone River in Montana (NPS Geologic Resources Division 2011).

Yellowtail Dam and Bighorn Lake were constructed by Reclamation for fish, wildlife, irrigation, municipal and industrial, flood control, power generation, and recreation purposes. Bighorn Lake extends almost 71 miles from near Lovell, Wyoming to Fort Smith, Montana. The maximum design storage of Bighorn Lake is 1,381,389 acre-feet at elevation 3660 feet; however sediment deposition has reduced the capacity to 1,331,725 acre-feet. Since 2000, lake levels have fluctuated between elevation 3640 feet (flood level) to 3572.7 feet (the historic low) (Reclamation 2012a). If water levels drop below elevation 3,547 feet, the hydroelectric power turbines at the existing Yellowtail Dam must be shut off. Reclamation recently revised the operation of Bighorn Lake to allow higher lake levels in late winter and early spring to benefit fish and provide a more reliable water supply during drought.

Downstream of Yellowtail Dam is an afterbay created by Yellowtail Afterbay Dam. The afterbay regulates the water discharge from the power plant at Yellowtail Dam. The Yellowtail Afterbay has a capacity of 3,141 acre-feet at an elevation of 3,192 feet and is operated between elevation 3,183 feet to elevation of 3,192 feet. Downstream of Yellowtail Afterbay Dam, the Bighorn River continues to its confluence with the Yellowstone River (NPS Geologic Resources Division 2011).

Three entities hold entitlements to water in Bighorn Lake including the Crow Tribe (300,000 acre-feet), the Northern Cheyenne Tribe (30,000 acre-feet), and Pennsylvania Power and Light of Montana (6,000 acre-feet).

Long-term operational impacts on surface water resources would be minimal under this project. The proposed volume of water that would be pumped into the new reservoir would be very small relative to the volume of water in the existing Bighorn Lake and would therefore be unlikely to noticeably change reservoir elevations. There would be no overall net change in storage. Any water pumped into the new reservoir would be returned to the existing reservoir. This project would not change the timing or frequency of releases from Bighorn Lake and would therefore not affect water supply.

Reclamation would need to obtain a water right to divert water for the pumped storage project. Reclamation would need to apply to the Montana Department of Natural Resource Conservation Water Rights Bureau for a water right permit. Water rights would need to comply with the Crow Tribe-Montana Compact.

11.1.1.4 Water Quality

The Bighorn River from Yellowtail Dam to Crow Indian Reservation boundary appears on the 2012 Montana 303d list as impaired for Nitrogen (total). No Total Maximum Daily Loads (TMDLs) has been completed for it. The Bighorn River from the Crow Indian Reservation boundary to the mouth (Yellowstone River) appears on the Montana 303d list as impaired by lead and mercury and the source is unknown. No TMDLs have been completed for these pollutants (Montana DEQ Water Quality Division 2012).

In 2009, the NPS completed water quality monitoring at Bighorn Canyon NRA. The sampling locations were generally south of the proposed new reservoir site and included Bighorn Lake and its tributaries. Overall, water quality data met most national and state standards; however nutrients exceeded the Montana draft nutrient standards developed to protect against adverse effects of eutrophication. Nutrients also exceeded state standards in several springs that were sampled. This suggests that geology may be partially responsible for some of the higher nutrient levels at some sites (NPS 2010).

Bighorn Lake has experienced substantial sediment accumulation, especially in the southern area of the reservoir. The high levels of sediment accumulation are caused by a variety of factors including the erodible quality of the bedrock, little vegetation in the floodplains, irrigated croplands, and steep stream gradients (NPS Geologic Resources Division 2011).

Temporary construction impacts on water quality in Bighorn Lake include increased turbidity from in-water work and stormwater runoff at the construction and staging sites. Use of equipment in and near the reservoir may introduce contaminants into the water. The permanent water quality impacts to Bighorn Lake could include slight changes in temperature as water is conveyed between the reservoirs.

11.1.1.5 Cultural Resources

The Bighorn Canyon NRA has identified a large variety of cultural resources including historic and prehistoric structures, archeological sites, and paleontological resources (fossils) within the park boundaries. Bighorn Canyon NRA is rich in cultural landscapes reflecting over 120 years of ranching, mining, tourism and irrigated agriculture. Four ranch sites within the park are on the National Register of Historic Places (NPS 2003).

The Bighorn Basin has been continuously occupied by humans for over 10,000 years. Hunter gatherers first visited the area for the large variety of plants and animals. Later, the Crow Indians migrated to the area because of pressure from Tribes to the east. The Crow Reservation is directly adjacent to the NRA.

Fossils at Bighorn Canyon NRA are primarily marine invertebrates and range in age from the Upper Ordovician Period (450 million years ago) to the Cretaceous Period (65 million years ago). Younger fossils occur within unconsolidated deposits at the NRA. A substantial number of Quaternary fossils has been found in the cave sediments of Natural Trap Cave on the western slope of the Bighorn Mountains, just outside the NRA (NPS Geologic Resources Division 2011).

Construction activities such as excavation and tunneling have the potential to damage or unearth cultural and/or paleontological resources. Creation of the new reservoir may permanently inundate known or previously unknown cultural or paleontological resources.

11.1.1.6 Indian Trust Resources

The Crow Reservation is in southeastern Montana, just south of Billings, Montana and surrounds the Bighorn Canyon NRA. The reservation is home to over 12,000 Crow enrolled tribal members and includes approximately 2,282,000 acres of land. There are 1,511,975 acres of tribal and allotted surface trust acreage (BIA 2013). The Crow Tribe has rights to 300,000 acre-feet of storage in Bighorn Lake, 500,000 acre-feet in natural flow of the Bighorn River, and the entire natural flow, groundwater, and storage in all other waterways on the Crow Reservation.

This project would require construction of the new reservoir on the Crow Tribe’s land holdings within Bighorn Canyon NRA. The temporary construction impacts to the Crow Tribe include dust, noise, and traffic, and the potential for disturbing known or previously unknown Native American artifacts, sites, or other cultural resources. Access to the construction site would likely be restricted during construction for public safety purposes.

The long-term impacts to the Crow Tribe include construction of permanent pumped storage structures, including a new reservoir and a permanent new road on the Crow Tribe’s land holdings, increased traffic associated with operation and maintenance of the new dam, reservoir, and associated facilities, and permanent inundation of a portion of the Crow Tribe’s land holdings. The pumped storage project would also need to comply with water rights associated with the Montana-Crow Tribe Compact.

11.1.1.7 Recreation

Bighorn Canyon NRA offers a wide variety of recreation activities including auto touring, bicycling, hiking, camping, fishing, hunting, horseback riding, picnicking, and wildlife viewing. Water-based recreation opportunities on Bighorn Lake include boating, swimming, water skiing, kayaking, and canoeing. The public is prohibited from entering the Crow Reservation that surrounds the NRA. Table 11-2 presents a list of boating facilities on Bighorn Lake and the surface water elevation operating levels.

Table 11-2. Bighorn Lake Boating Facilities and Operating Levels

Ramp Name	Facility Type	Surface Water Elevation
Ok-A-Beh	Launch Ramp Courtesy Docks Marina & Gas Docks Swim Beach	3580 Feet 3590 Feet 3600 Feet 3610 Feet
Barry's Landing	Launch Ramp Courtesy Docks	3580 Feet 3590 Feet
Horseshoe Bend	Launch Ramp Courtesy Docks Swim Beach	3617 Feet 3620 Feet 3625 Feet
Black Canyon	Courtesy Docks	3620 Feet
Medicine Creek	Courtesy Docks	3620 Feet

Source: NPS 2013a.

Construction-related impacts to recreation at the Bighorn Canyon NRA include restricted access to a portion of the Bighorn Lake shoreline and water area where the new dam, reservoir, and associated facilities would be constructed. This may result in a decrease in overall visitor use; however, because no major park facilities are located at the proposed reservoir site, any decreases would likely be small. There would be very few long-term impacts to recreation. As noted above, water levels at the lake are not expected to decrease below the minimum operating levels of the existing boat ramps and would therefore not affect water-based recreation. There may be some areas around the new facilities that restrict public access for safety reasons.

11.1.1.8 Land Use

The new reservoir under this project would be constructed in the Bighorn Canyon NRA, managed by NPS. Construction of this project would likely require permission from the NPS through a Special Use Permit. Reclamation would also need to coordinate with the Crow Tribe for any use of Crow Tribe land holdings.

11.1.1.9 Traffic

There are currently no roads that provide direct access to the proposed pump storage site. The main road closest to the proposed reservoir site is within the Crow Reservation.

Construction of this project would require a new permanent access road in difficult terrain because of the changes in elevation. The access road would likely need to be constructed on the Crow Reservation and on the Crow Tribe's land holdings within Bighorn Canyon NRA.

Construction of the new dam would require a substantial quantity of earth (approximately 7.7 million cubic yards) to be transported to the dam site, as well as other construction materials. This would increase traffic on existing Crow Reservation roads for the duration of construction.

There would be some long-term traffic impacts due to required maintenance of the new dam, reservoir, power station, and other associated facilities.

11.1.1.10 Air Quality

The area surrounding Bighorn Canyon NRA is in attainment for both National Ambient Air Quality Standards (NAAQS) and Montana Ambient Air Quality Standards (MAAQS) (Montana DEQ Air Quality Division 2011). Temporary air quality impacts from construction would include construction vehicle and equipment emissions as well as an increase in particulate matter (dust). Long-term impacts to air quality could include emissions from new equipment such as backup diesel generators and the HVAC system for the power station.

11.1.2 Permitting

Table 11-3 lists the preliminary permits, approvals, or consultations expected to be required for this project. This list will need to be updated as the project is further developed.

- FERC license for pumped storage projects
- MOU with Crow Indians
- NPS permit for working within boundaries
- NHPA Section 106 consultation
- 404/Section 10 Permit
- Section 7 Consultation

Table 11-3. Potential Permits and Approvals for Yellowtail Pumped Storage Project

Permit/Approval/Consultation	Entity	Description
Federal		
CWA Section 404 Placement of dredge and fill in wetlands and other waters of the U.S.	USACE	Impacts to wetlands and other waters of the U.S. under USACE jurisdiction
CWA Section 401 Water Quality Certification	Montana DEQ Water Quality Division	Ensure project is consistent with Federal and State water quality standards
Federal ESA Section 7 Consultation	USFWS	Impacts to Federally listed species
Fish and Wildlife Coordination Act	USFWS, Montana Fish, Wildlife, and Parks	Water projects with effects on wildlife
NHPA Section 106 Consultation	Montana SHPO	Impacts to cultural resources and historic properties
CWA Section 402 NPDES Permit	Montana DEQ Water Quality Division	Stormwater discharges from construction sites
Section 10 Rivers and Harbors Act Approval	USACE	Impacts to navigable waters
Original Hydropower License	FERC	New Pumped Storage Facility
Special Use Permit	NPS	Actions occurring on lands managed by NPS
Government-to-Government Consultation	BIA and Crow Tribe	Actions on Crow Tribe land holdings

Table 11-3. Potential Permits and Approvals for Yellowtail Pumped Storage Project

Permit/Approval/Consultation	Entity	Description
State		
Montana Environmental Policy Act	State Agency issuing permits or licenses (Montana DEQ)	Any planning activities or decisions made by State agencies that may affect the environment are required to do an environmental review pursuant to MEPA
Stationary Source Permit	Montana DEQ Air Quality Division	Operation of diesel generators, batch plants, rock crushing plants
Wildlife Consultation	Montana Department of Fish, Wildlife and Parks	Impacts to Montana fish and wildlife
Water Right	Water Rights Bureau	Right to divert water

Key:
BIA = Bureau of Indian Affairs
DEQ = Department of Environmental Quality
FERC = Federal Energy Regulatory Commission
MEPA = Montana Environmental Policy Act
SHPO = State Historic Preservation Act
USACE = United States Army Corps of Engineers
USFWS = United States Fish and Wildlife Service

11.2 Seminoe Site

11.2.1 Potential Environmental Effects

11.2.1.1 Fisheries

Seminoe Reservoir supports several game fish, including Brown trout, Rainbow trout, cutthroat trout, and Walleye (WGFD & WDH 2012). The reservoir also supports several non-game fish species including carp, lake chub, emerald shiner, white sucker, longnose sucker and fathead minnow. Game fish present in the North Platte River downstream of Seminoe Reservoir include Brown trout, Rainbow trout, cutthroat trout, and Walleye. Non-game fish in the river include bigmouth shiner, creek chub, carp, emerald shiner, Iowa darter, longnose dace, longnose sucker and white sucker (BLM 2005).

Temporary construction-related impacts to fish in Seminoe Reservoir would include increased turbidity from in-water work for the tunnels, and intake. These effects would be reduced (but not fully avoided) by implementation of BMPs.

There may be some temporary and permanent loss of fish habitat along the shoreline of the reservoir from construction of the various facilities. Long-term impacts to fish could occur from entrainment at the new intake that would allow water to be pumped from the existing Seminoe Reservoir into the new reservoir, but fish effects would be minimized by incorporating a fish screen in the intake design.

The proposed volume of water that would be pumped into the new reservoir would be very small relative to the volume of water in the existing Seminoe Reservoir and would therefore be unlikely to change reservoir elevations such that there would be adverse effects to existing fish. There would be no net change in overall storage; therefore, releases from Seminoe Reservoir would not change. This project would not have adverse impacts to the coldwater pool, or downstream temperatures that could affect fish.

11.2.1.2 Vegetation and Wildlife

Vegetation surrounding Seminoe Reservoir consists of sand dunes, yucca, greasewood, sagebrush, salt sage, willows, and marsh grasses. There are few trees in the park with the exception of pines and junipers near the dam. A variety of wildlife is present in and around Seminoe State Park including mule deer, pronghorn, coyotes, and migratory birds (WSPHST 2012).

Seminoe 5C is in the Morgan Creek Wildlife Habitat Management Area (WHMA), which contains sagebrush grasslands, conifers, aspen groves and grassy meadows. The wildlife species that can be found at the WHMA include elk and bighorn sheep, mule deer, Yellow-bellied marmots, coyotes, and red foxes. There are also a variety of songbirds, including the Clark's nutcracker and the canyon wren. Blue grouse can also be found in the area and Pronghorn antelope can occasionally be seen on lands surrounding the WHMA (WGFD 2008).

Seminoe 5A2 and parts of Seminoe 5A3 are in the Bennett Mountain Wilderness Study Area (WSA). Vegetation in the Bennett Mountain WSA is mainly grasses, sagebrush and shrubs, with several areas of pine, aspen and willows (BLM 2011a). The WSA provides important habitat for elk and deer. Pika, marmots, golden eagles, and other raptors, are also present.

Special-status wildlife species listed under the Federal Endangered Species Act (ESA) in the area surrounding Seminoe Reservoir are presented in Table 11-4.

Table 11-4. Special-Status Wildlife Species near Seminoe Reservoir

Special-Status Species	Status
Greater sage-grouse	C
Least tern	E
Piping Plover	T
Whooping crane	E
Whooping crane	EP/NE
Pallid sturgeon	E

Table 11-4. Special-Status Wildlife Species near Seminoe Reservoir

Special-Status Species	Status
Blowout penstemon	E
Ute ladies'-tresses	T
Western Prairie Fringed Orchid	T
Black-Footed ferret	EP/NE

Source: USFWS 2013c.
Key:
C - Candidate
E – Endangered
T – Threatened
EP/NE - Experimental Population, Non-Essential

The Greater Sage-Grouse is currently a candidate for listing as endangered or threatened under the Federal ESA. The State of Wyoming has an abundance of sage-brush stepp habitat that supports Sage-Grouse and recognizes that listing the species would have an adverse effect on its culture and economy. In response, Wyoming has developed a strategy to manage and conserve the species and their habitat to preclude the need for listing. In compliance with Executive Order (EO 2011-05), the State of Wyoming has identified "Core Population Areas" for Greater Sage-Grouse. Activities that occur within these designated areas must demonstrate they will not cause declines in Greater Sage-Grouse populations. All permits issued by the State of Wyoming first require consultation with WFGD to ensure the activity is in compliance with Sage-Grouse requirements. Appendix B of EO 2011-05 provides a list of measures that should be implemented to avoid impacts to the species. The proposed reservoir sites would occur within designated "Core Population Areas" for Sage-Grouse; therefore, they would require consultation with WGFD and implementation of measures to prevent impacts to the species and their habitat.

Temporary construction-related impacts on vegetation and wildlife from this project would include removal of vegetation for construction and staging, as well as dust, noise, and vibration impacts. Use of equipment and vehicles would have the potential to physically damage wildlife and their habitat. There may also be impacts to special-status species and their habitat.

There would be permanent loss of vegetation for construction of the new access road, dam, reservoir, and associated pump-generation facilities. An area currently containing vegetation would be permanently submerged under water once the new reservoir is filled and could inundate existing wildlife habitat. The new reservoir would create new aquatic habitat. In the Morgan Creek WHMA or the Bennett Mountain WSA, the presence of a new road that would be used for routine maintenance, could harm wildlife and would have noise, dust, and vibration impacts. The new reservoir and other associated facilities have the potential to fragment wildlife habitat or corridors.

11.2.1.3 Surface Water Resources

Seminoe Dam is on the North Platte River 72 miles west of Casper, Wyoming, and forms Seminoe Reservoir, part of the Kendrick Project operated by Reclamation. Seminoe Reservoir has a storage capacity of 1,017,273 acre-feet at an elevation of 6357.0 feet. The reservoir was constructed for irrigation and hydropower. There is no authorized flood storage capacity.

Long-term operational impacts on surface water resources would be minimal under this project. The proposed volume of water that would be pumped into the new reservoir would be very small relative to the volume of water in the existing Seminoe Reservoir and would therefore be unlikely to substantially change reservoir elevations. There would be no overall net change in storage. Most of the water pumped into the new reservoir would be returned to the existing reservoir. This project would not change the timing or frequency of releases from Seminoe Reservoir and would therefore not affect overall water supply or downstream flows.

Reclamation would need to obtain a water right to divert water for the pumped storage project. Reclamation would need to apply to the Wyoming State Engineer for a water right permit.

11.2.1.4 Water Quality

The main water quality issue in Seminoe Reservoir is nutrients; however, the reservoir empties enough each year to prevent eutrophic conditions. Methyl mercury concentrations in large walleye have been found to exceed EPA guidelines of 0.3 mg/kg of fish, prompting a fish consumption advisory (WGFD and WHD 2012). Seminoe Reservoir is not currently listed on the Wyoming 2012 303d list as impaired (Wyoming DEQ Division of Water Quality 2012).

The State of Wyoming has classified "The Miracle Mile" as Class 1 water body, where no additional water quality degradation will be allowed (no new point source discharges are permitted and nonpoint source discharges are carefully regulated). Seminoe Reservoir is classified Class 2AB water body supporting both drinking water and game fish (Wyoming DEQ Division of Water Quality 2012).

Temporary construction impacts on water quality in Seminoe Reservoir include increased turbidity from in-water work and stormwater runoff at the construction and staging sites. Use of equipment in and near the reservoir may introduce contaminants into the water.

The permanent water quality impacts to Seminoe Reservoir could include slight changes in temperature as water is moved between the reservoirs.

11.2.1.5 Cultural Resources

Very little of Carbon County, Wyoming has been surveyed for cultural resources; however, the potential for encountering cultural resources around

Seminoe Reservoir is high because humans have inhabited the area for over 12,000 years. Cultural resources in the area are likely to include archeological sites, historic sites and properties, and properties that are sacred to Native American cultures (BLM 2004).

A cultural resource inventory was conducted in the Morgan Creek WHMA and on surrounding BLM grazing lands in 2011. Cultural properties that were identified include historic buildings and structures related to ranching, homesteading, and mining. Also identified were historic power lines and structures associated with the Seminoe and Kortes dams and power plants (BLM 2011b).

Construction activities, including excavation and tunneling, have the potential to damage or unearth cultural and/or archaeological resources. Creation of the new reservoir may permanently inundate known or previously unknown cultural or archaeological sites.

11.2.1.6 Indian Trust Resources

There are no known Indian Reservations within the project area. The nearest Indian Reservation is Wind River Indian Reservation, over 100 miles to the northwest. There would be no impacts to Indian Trust Resources.

11.2.1.7 Recreation

The two proposed new reservoirs sites are adjacent to the Seminoe State Park. Seminoe State Park includes 20,191 acres at the north end of Seminoe Reservoir and is managed by Wyoming State Parks and Historic Sites and Trails under an agreement with Reclamation. The park offers boating, camping, fishing, swimming, wildlife viewing, picnic areas, and a playground. Table 11-5 presents the boat ramps available at Seminoe State Park and their minimum operating levels. In 2011, there were 23,600 visitors to the park, and there were 21,358 in 2012 (WSPCR 2012).

Table 11-5. Seminoe State Park Boating Facilities and Operating Levels

Ramp Name	Surface Water Elevation
Boat Club (Private)	6314 Feet
Medicine Bow	6324.8 Feet
North Red Hills	
1	6323.6 Feet
2	6309.9 Feet
3	6300.9 Feet
South Red Hills	6312.6 Feet

Source: Reclamation 2012b

The Morgan Creek WHMA is on the northwest side of Seminoe Reservoir and includes 4,125 acres of land. It is managed by Wyoming Game and Fish Department through an agreement with Reclamation. The Morgan Creek

WHMA was originally established for transplanted bighorn sheep, and now also contains transplanted elk from Yellowstone National Park. The WHMA allows for hiking and wildlife viewing. Camping and hunting are allowed just south of the WHMA in the Miracle Mile Area (WGFD 2008).

The Bennett Mountain WSA contains 6,003 acres of land on the northeast side of Seminoe Reservoir. It is managed by BLM and allows for primitive recreation opportunities including hunting, hiking, trapping, camping, wildlife viewing, and sightseeing. There are no developed recreation facilities (BLM 2011a).

The “Miracle Mile” is a 5.5 mile stretch of the North Platte River between Kortes Dam and Pathfinder Reservoir. This river is well known for its abundance of large trout and is an extremely popular fishing site. Camping is permitted along both sides of the river.

Construction-related impacts to recreation at the Seminoe State Park could include restricted access to a portion of the shoreline and water area where the new dam, reservoir, and associated facilities would be built to ensure public safety. This may result in a decrease in overall visitor use; however, it would be temporary. There would be very few long-term impacts to recreation at the Seminoe State Park. As noted above, water levels at the reservoir are not expected to decrease below the minimum operating levels for the existing boat ramps. There may be some areas around the new facilities that restrict public access for safety reasons.

Under Seminoe 5C, construction impacts at the Morgan Creek WHMA could include restricted access to a portion of the WHMA. Under Seminoe 5A2, construction impacts would include restricted recreation access in the Bennett Mountain WSA at the new reservoir site. Visitor use to these areas could decrease during construction due to dust, noise, construction equipment, and restricted access.

Creation of the new pump storage facilities in the Bennett Mountain WSA under Seminoe 5A2 and 5A3 would permanently alter the recreational experience. The WSA is meant to remain in a natural state without man-made structures and should allow for solitude and primitive recreation. The presence of a new dam, reservoir, and associated facilities as well as a new access road would be considered a long-term adverse effect on the overall wilderness recreation experience.

11.2.1.8 Land Use

The area surrounding Seminoe Reservoir consists mainly of federally owned lands. Seminoe State Park lands are owned by Reclamation and managed by Wyoming State Parks, Historic Sites, and Trails. Morgan Creek WHMA is directly to the northwest of the Seminoe State Park. The WHMA lands are owned by Reclamation and managed by WGFD.

The eastern lands adjacent to Seminoe State Park are owned by BLM and include the Bennett Mountain WSA. The Federal Land Policy and Management Act of 1976 directed the BLM to inventory and study its roadless areas for wilderness characteristics. The WSA designation requires an area greater than 5,000 acres with no roads that remains in a natural state, and provides outstanding opportunities for solitude and primitive recreation. Congress reviews these areas and can give them wilderness status or can release them for other uses. The Bennett Mountains WSA was not recommended for wilderness status in a 1992 report to Congress; however Congress has not made a ruling on any of the WSAs. Until Congress makes a final determination on a WSA, the BLM continues to manage the area to preserve its suitability for designation as wilderness (BLM 2013). Construction of pipelines, roads, and other infrastructure is generally not permitted within WSAs.

Seminoe 5C would be constructed within the Morgan Creek WHMA. This would require an agreement with WGFD and could require specific measures to protect the existing wildlife and habitat.

Seminoe 5A2 and 5A3 would be constructed on BLM lands in the Bennett Mountain WSA. Construction could impair the suitability of the wilderness area and could conflict with its designation as a WSA.

11.2.1.9 Traffic

Most of the local roads surrounding Seminoe Reservoir are unimproved (gravel). The west side of Seminoe Reservoir is accessible by Carbon County Road 351 (Seminoe Road). This road leads directly to the Seminoe State Park office. For the proposed new reservoir site under Seminoe 5C, an access road would need to be constructed to connect the new reservoir site to Road 351.

The sites in the Bennett Mountain WSA would be further from an existing road. There are no roads within the Bennett Mountains WSA as this is a requirement for its designation as a WSA. The Bennett Mountains WSA can be accessed using Leo-Hanna Road and Bennett Mountain Road. The Bennett Mountain WSA area can also be accessed by BLM Road 3159; however this road travels across some private lands and permission would be required from the landowners. An access road would need to be constructed to allow construction traffic to access the site.

Construction of this project would require a new permanent access road, either through the Morgan Creek WHMA and Seminoe State Park, or through the Bennett Mountain WSA. An access road through the Bennett Mountain WSA would impair suitability of the wilderness area and would not be compatible with its current designation as a WSA.

Construction of the new dam would require a substantial quantity of earth to be transported to the dam site, along with a variety of other construction materials.

This would increase traffic on existing roads for the duration of construction, which extend for several years.

There would be some long-term traffic impacts due to required maintenance of the new dam, reservoir, power station, and other associated facilities; however it would be less traffic than that expected during construction.

11.2.1.10 Air Quality

The Seminoe Reservoir area is rural and has been designated by the Wyoming DEQ Air Quality Division as in attainment for National Ambient Air Quality Standards and Wyoming Ambient Air Quality Standards (Wyoming DEQ Air Quality Division 2012).

Temporary air quality impacts from construction would include construction vehicle and equipment emissions as well as an increase in particulate matter (dust). While these emissions would only last the duration of construction, the amount of earth needed to construct the dam and the duration of construction (several years) could result in substantial emissions. Long-term impacts to air quality could include emissions from new equipment such as backup diesel generators and the HVAC system for the power station.

11.2.2 Permitting

Several permits, approvals, and consultations have been identified for Seminoe sites (Table 11-6). Additional permitting needs would need to be further evaluated in future analyses.

Table 11-6. Potential Permits and Approvals for Seminoe Pumped Storage Projects

Permits and Approvals	Approving Agency/Entity	Description
Federal		
CWA Section 404 Placement of dredge and fill in wetlands and other waters of the U.S.	USACE	Impacts to wetlands and other waters of the U.S. under USACE jurisdiction
CWA Section 401 Water Quality Certification	Wyoming DEQ Water Quality Division	Ensure project is consistent with Federal and State water quality standards
Federal ESA Section 7 Consultation	USFWS	Impacts to Federally listed species
Fish and Wildlife Coordination Act	USFWS, Montana Fish, Wildlife, and Parks	Water projects with effects on wildlife
NHPA Section 106 Consultation	Wyoming SHPO	Impacts to cultural resources and historic properties
CWA Section 402 NPDES Permit	Wyoming DEQ Water Quality Division	Stormwater discharges from construction sites
Section 10 Rivers and Harbors Act Approval	USACE	Impacts to navigable waters
Original Hydropower License	FERC	New Pumped Storage Facility
Special Use Permit	BLM	Actions occurring on lands managed by BLM

Table 11-6. Potential Permits and Approvals for Seminoe Pumped Storage Projects

Permits and Approvals	Approving Agency/Entity	Description
State		
Consultation/Special Purpose Permit	Wyoming Game and Fish Department	Impacts to special-status species/Take of Wyoming wildlife
Special Use Permit	Wyoming Game and Fish Department	Work within Wildlife Habitat Management Area
Consultation /Letter of Approval stating Consistency with Executive Order (EO 2011-4)	Wyoming Game and Fish Department	Projects that would affect Sage-Grouse Core Areas Note: This is required before a Construction Stormwater Permit can be issued.
Consultation for Compliance with Construction General Emission Standards	Wyoming DEQ – Air Quality Division	Construction emissions
Consultation/Permission from Park Superintendent	Wyoming State Parks and Cultural Resources	Any work that would take place in a Wyoming State Park
Water Right	Wyoming State Engineer	Right to divert water

Key:
BLM = Bureau of Land Management
DEQ = Department of Environmental Quality
FERC = Federal Energy Regulatory Commission
SHPO = State Historic Preservation Act
USACE = United States Army Corps of Engineers
USFWS = United States Fish and Wildlife Service

11.3 Trinity Site

11.3.1 Potential Environmental Effects

11.3.1.1 Fisheries

The Trinity River supports multiple populations of native anadromous species including Chinook salmon, coho salmon, and steelhead, green sturgeon and Pacific lamprey. In addition to anadromous fish species, the Trinity River also supports multiple resident fish species including rainbow trout, speckled dace, Klamath smallscale sucker, Klamath River lamprey, three-spined stickleback, coast range sculpin, and marbled sculpin, American shad, brown bullhead, green sunfish, brown trout, and brook trout.

Special-status fish species listed under the Federal or State ESA, proposed for listing, or identified by the California Department of Fish and Wildlife as a species of special concern and/or California Fully Protected Species in the study area are presented in Table 11-7 below.

Table 11-7. Special Status Fish Species for Trinity Pumped Storage Project

Name	Status
green sturgeon	T
S. OR/N. CA coho salmon	T
winter-run chinook salmon	E
Klamath Mountains Province (KMP) ESU of steelhead	CSC
spring-run Chinook salmon	CSC

Key:
E – Endangered
T – Threatened
CSC - California Species of Concern
Source: USFWS 2013d, North Coast Regional Water Quality Control Board 2009

The Trinity River Restoration Program was established in 2000 in response to multiple studies on the decline of salmon and steelhead populations in the Trinity River following the construction and operation of the Trinity River Division of the Central Valley Project in 1964. The Trinity River Restoration Program established a variable flow management regime to mimic more natural flows along with channel rehabilitation, sediment management and watershed restoration actions to improve habitat suitability for the salmon and steelhead populations. The flow and riverbed modification actions were designed to recreate at a smaller scale the variable channel characteristics of the pre-diversion river. Fish populations in the Trinity River and Klamath River downstream are still however susceptible to stresses from high water temperatures and low water flows. In September 2002, at least 33,000 adult salmon, many of which were headed to the Trinity River to spawn, died in the mainstem of the Klamath River downstream of the Trinity River. Later studies on the die-off identified low flows and high water temperatures and their promotion of a fish disease, as the primary cause of this event.

Construction of the pumped storage project at Trinity Reservoir would increase turbidity from in-water work for the tunnels, and intake. These effects would be reduced (but not fully avoided) by implementation of BMPs.

There may be some temporary and permanent loss of fish habitat along the shoreline of the reservoir from construction of the various facilities. Long-term impacts to fish could occur from entrainment at the new intake that would allow water to be pumped from the existing Trinity Reservoir into the new reservoir, but fish effects would be minimized by incorporating a fish screen in the intake design.

The proposed volume of water that would be pumped into the new reservoir would be very small relative to the volume of water in the existing reservoir and would therefore be unlikely to change reservoir elevations such that there would be adverse affects to existing fish. There would be no net change in overall storage; therefore, releases from Trinity Reservoir would not change. This project would not have adverse impacts to the coldwater pool, or downstream temperatures that could affect fish.

11.3.1.2 Vegetation and Wildlife

The vegetation in the Trinity River watershed is mainly mixed conifer, with some hardwoods, shrubs and grasslands. The mixed conifer stands are valuable for commercial timber harvesting (USDA Forest Service 2005). Riparian vegetation along the Trinity River downstream of Lewiston Dam includes early successional, willow-dominated vegetation; mature, later-successional, alder dominated vegetation; and willow-alder mix. Species supported by this riparian vegetation include rough-skinned newt (Taricha granulosa), western aquatic garter snake (Thamnophis couchi), foothill yellow-legged frog (Rana boylii), western pond turtle (Actinemys marmorata), northern goshawk (Accipiter gentiles) and black salamander (Aneides flavipunctatus), American dipper (Cinclus mexicanus), black bear (Ursus americanus), bald eagle (Haliaeetus leucocephalus), and other scavengers.

Trinity and Lewiston reservoirs create open water habitat that attracts resting and foraging waterfowl and other species that favor standing or slow-moving water. This includes eagles and other raptors that rely on the reservoirs for foraging habitat.

Special-status fish species listed under the Federal or State ESA, proposed for listing, or identified by the California Department of Fish and Wildlife as a species of special concern and/or California Fully Protected Species in the study area are presented in Table 11-8.

Table 11-8. Federally Listed Species for Trinity Pumped Storage Project

Name	Status
California red-legged frog	T
Western yellow-billed cuckoo	C
northern spotted owl	T
fisher, West Coast DPS	C
McDonald's rock cress	E
Baker's globe mallow	CSC
California globe mallow	CSC
Canyon Creek stonecrop	CSC
Clustered lady's-slipper	CSC
Dubakella Mountain buckwheat	CSC
Dudley's rush	CSC
Elongate copper moss	CSC
English Peak greenbriar	CSC
Flaccid sedge	CSC
Fox sedge	CSC
Heckner's lewisia	CSC
Howell's alkali grass	CSC
Howell's lewisia	CSC
Howell's montia	CSC
Klamath Mountain catchfly	CSC

Table 11-8. Federally Listed Species for Trinity Pumped Storage Project

Name	Status
Moonwort, grape-fern	CSC
Mountain lady's-slipper	CSC
Nile's harmonia	CSC
Northern adder's-tongue fern	CSC
Northern clarkia	CSC
Oregon willow herb	CSC
Peanut sandwort	CSC
Pickering's ivesia	CSC
Regel's rush	CSC
Scott Mountain fawn lily	CSC
Scott Mountain bedstraw	CSC
Serpentine goldenbush	CSC
Shasta chaenactis	CSC
Showy raillardella	CSC
Trinity bristle snail	T
California red-legged frog	T
American peregrine falcon	E/FP
Bank swallow	T
Marbled murrelet	E
Little willow flycatcher	E
Western yellow-billed cuckoo	E
California wolverine	T/FP
Pacific fisher	CSC
Tailed frog	CSC
Foothill yellow-legged frog	CSC
Cascades frog	CSC
Western pond turtle	CSC
Black swift	CSC
California yellow warbler	CSC
Golden eagle	FP
Northern goshawk	CSC
Vaux's swift	CSC
Yellow-breasted chat	CSC
Fringed myotis	CSC
Long-eared myotis	CSC
Oregon snowshoe hare	CSC
Pallid bat	CSC
Ring-tailed cat	FP
Townsend's western big-eared bat	CSC
American marten	CSC
Yuma myotis	CSC

Source: USFWS 2013d, North Coast Regional Water Quality Control Board 2009
Key:
E – Endangered
T – Threatened
CSC - California Species of Concern
FP – Fully Protected

Temporary construction-related impacts on vegetation and wildlife would include removal of vegetation for construction and staging, as well as dust, noise, and vibration impacts. Use of equipment and vehicles would have the potential to physically damage wildlife and their habitat. There may also be impacts to special-status species and their habitat.

There would be permanent loss of vegetation for construction of the new access road, dam, reservoir, and associated pump-generation facilities. An area currently containing vegetation would be permanently submerged under water once the new reservoir is filled and could inundate existing wildlife habitat. The new reservoir would create new aquatic habitat. The presence of a new road that would be used for routine maintenance, could harm wildlife and would have noise, dust, and vibration impacts. The new reservoir and other associated facilities have the potential to fragment wildlife habitat or corridors.

11.3.1.3 Surface Water Resources

The Trinity River originates in the northeast near Mount Eddy and flows west 110 miles to where it joins the Klamath River. The two reservoirs on the Trinity River include Trinity and Lewiston reservoirs. Trinity Dam on the Trinity River stores water in Trinity Reservoir for hydropower, flood control and recreation. Trinity Reservoir has a storage capacity of 2,448,00 acre-feet at elevation 2,450 feet, contains a surface area of 15,640 acres, and has over 145 miles of shoreline.

Lewiston Dam is about 7 miles downstream of Trinity Dam. The reservoir has a capacity of 14,660 acre-feet and a surface area of 673 acres. Streamflow into Lewiston Lake is regulated by Trinity Reservoir releases. Water diverted from Lewiston Lake is used to generate power. A large quantity of Trinity Basin water is diverted to the Sacramento River Basin at Lewiston Dam (USDA Forest Service 2005).

Long-term operational impacts on surface water resources would be minimal under this project. The proposed volume of water that would be pumped into the new reservoir would be very small relative to the volume of water in the existing Trinity Reservoir and would therefore be unlikely to noticeably change reservoir elevations. There would be no overall net change in storage. Any water pumped into the new reservoir would be returned to the existing reservoir. This project would not change the timing or frequency of releases from Trinity or Lewiston reservoirs and would therefore not affect water supply.

Reclamation would need to obtain a water right to divert water for the pumped storage project. The water right would be for a non-consumptive use. Reclamation would need to apply to the State Water Resources Control Board (SWRCB) for a water right permit.

11.3.1.4 Water Quality

Trinity Reservoir is listed as impaired by mercury on the 2010 California 303d list. A total maximum daily load has not yet been established. The Trinity River is listed as impaired for sediment, mercury, and temperature. A maximum daily load for sediment has been established because the sediment is affecting water quality and fish (SWRCB 2010).

Temporary construction impacts on water quality in Trinity Reservoir include increased turbidity from in-water work and stormwater runoff at the construction and staging sites. Use of equipment in and near the reservoir may introduce contaminants into the water.

The permanent water quality impacts to Trinity Reservoir could include slight changes in temperature as water is moved between the reservoirs; however, the large size of Trinity Reservoir would minimize this effect and the project would not have adverse impacts to the coldwater pool, or downstream temperatures.

11.3.1.5 Cultural Resources

The Trinity River Basin is a culturally significant area for several Native American tribes including the Hoopa Valley, Wintu, and Yurok. These tribes have inhabited and relied on the river basin's natural resources including salmon fishing since before written history and European influence, and continue to do so today. The first recorded European exploration of the Trinity River Basin occurred in 1845 and gold was discovered in the region in 1848, triggering the development of multiple boom towns in the region.

A cultural resource inventory was conducted in the Trinity River Basin as a part of the Trinity River Restoration Program in an area of potential effect defined as the 500 year floodplain from Trinity Reservoir to the Hoopa Valley Indian Reservation. Cultural resources that were identified included historic villages at traditional salmon fishing sites, villages associated with secondary resource procurement areas, ceremonial sites, burial sites, historic buildings and structures related to ranching, homesteading, and mining.

Construction activities, including excavation and tunneling, have the potential to damage or unearth cultural and/or archaeological resources. Creation of the new reservoir may permanently inundate known or previously unknown cultural or archaeological sites.

11.3.1.6 Indian Trust Resources

The Hoopa Valley Tribe and Yurok Tribe are both Federally recognized with reservations downstream of Trinity Reservoir. The Hoopa Valley Tribe's reservation is in the Hoopa Valley along the Trinity River and is home to approximately 2,500 Hupa people. The Yurok Reservation begins immediately downstream of the Trinity River's confluence with the Klamath River and extends one mile on each side of the Klamath River from its mouth upstream for 44 miles. The Yurok Tribe has approximately 5,000 enrolled members. Both the

Hoopa Valley Tribe and Yurok Tribe have specific tribal trust interests in fisheries, wildlife, tribal trust, and cultural resources.

This project would construct a new reservoir near Trinity Reservoir upstream of the Hoopa Valley Tribe and Yurok Tribe reservations. The temporary construction impacts include local dust, noise, and traffic effects that would not extend to either reservation. There would, however, be the potential for disturbing known or previously unknown Native American artifacts, sites, or other cultural resources.

The long-term impacts to the Hoopa Valley Tribe and Yurok Tribe include some permanent loss of vegetation for construction of the road and inundation of the reservoir and the associated terrestrial resource effects in the region. The footprint of the new reservoir is small and its distance from either reservation would limit the size of any potential effect on Indian trust resources.

11.3.1.7 Recreation

The entire mainstem of the Trinity River below Lewiston Dam is designated as a Wild and Scenic River. The main stem Trinity River is classified as recreational and scenic under the California Wild and Scenic Rivers Act (USDA Forest Service 2005). Trinity Reservoir has a shoreline of approximately 120 miles and a surface area of approximately 16,400 acres utilized for flat water recreation. Lewiston Reservoir downstream of Trinity Dam is also used as a recreation resource in the study area, although to a lesser degree than Trinity Reservoir.

Construction-related impacts to recreation at the Trinity Reservoir could include restricted access to a portion of the shoreline and water area where the new conveyance and intake facilities would be built to ensure public safety. This may result in a decrease in overall visitor use; however, it would be temporary. There would be very few long-term impacts to recreation at Trinity Reservoir. As noted above, water levels at the reservoir are not expected to decrease below the minimum operating levels for the existing boat ramps. There may be some areas around the new facilities that restrict public access for safety reasons.

Creation of the new pump storage facilities in the Whiskeytown-Shasta-Trinity NRA would replace a small vegetated area currently available for passive recreation with a small surface water storage facility that would also be available for passive recreation. The presence of a new dam, reservoir, and associated facilities as well as a new access road would be considered a permanent change in the recreation experience in this small portion of the NRA.

11.3.1.8 Land Use

This project proposes a reservoir in the Whiskeytown-Shasta-Trinity NRA. This NRA is managed by the U.S. Forest Service. Construction of this project would likely require permission from the U.S. Forest Service through a Special Use Permit.

11.3.1.9 Traffic

Construction of this project would require the use of an existing access road in the Whiskeytown-Shasta-Trinity NRA.

Construction of the new dam would require a substantial quantity of earth (approximately 2.9 million cubic yards) to be transported to the dam site, as well as other construction materials. This would increase traffic on existing roads in the study area for the duration of construction.

There would be some long-term traffic impacts due to required maintenance of the new dam, reservoir, power station, and other associated facilities.

11.3.1.10 Air Quality

The Trinity County area is rural and has been designated by the North Coast Air Quality Management District as in attainment for Federal and State Ambient Air Quality Standards with the exception of PM_{10} (NCAQMD 2013).

Temporary air quality impacts from construction would include construction vehicle and equipment emissions as well as an increase in particulate matter (dust). While these emissions would only last the duration of construction, the amount of earth needed to construct the dam and the duration of construction (several years) could result in substantial emissions. Long-term impacts to air quality could include emissions from new equipment such as backup diesel generators and the HVAC system for the power station.

11.3.2 Permitting

Several permits, approvals, and consultations have been identified for this site (Table 11-9). Additional permitting needs would need to be further evaluated in future analyses.

Table 11-9. Potential Permits and Approvals for Trinity Pumped Storage Project

Permits and Approvals	Approving Agency/Entity	Description
Federal		
CWA Section 404 Placement of dredge and fill in wetlands and other waters of the U.S.	USACE	Impacts to wetlands and other waters of the US under USACE jurisdiction
CWA Section 401 Water Quality Certification	Regional Water Quality Control Board	Ensure project is consistent with Federal and State water quality standards
Federal ESA Section 7 Consultation	USFWS, NMFS	Impacts to Federally listed species
Fish and Wildlife Coordination Act	USFWS, CDFG	Water projects with effects on wildlife
NHPA Section 106 Consultation	California SHPO	Impacts to cultural resources and historic properties
CWA Section 402 NPDES Permit	Regional Water Quality Control Board	Stormwater discharges from construction sites
Section 10 Rivers and Harbors Act Approval	USACE	Impacts to navigable waters
Original Hydropower License	FERC	New Pumped Storage Facility

Table 11-9. Potential Permits and Approvals for Trinity Pumped Storage Project

Permits and Approvals	Approving Agency/Entity	Description
Special Use Permit	US Forest Service	Actions occurring on lands managed by US Forest Service
State		
California Environmental Quality Act	State Agency	Required for any State Agency approving permits for project or providing funding
California ESA Section 2081 Incidental Take Permit or 2080.1 Consistency Determination	CDFW	Impacts to State listed species
Fish and Game Code 1602 Streambed Alteration Agreement	CDFW	Alterations to stream or streambed Note: Only required for State Agencies; not required for Federal Agencies.
Water Right	State Water Resources Control Board	Right to divert water for non-consumptive use.

Key:
BLM = Bureau of Land Management
CDFW = California Department of Fish and Wildlife
FERC = Federal Energy Regulatory Commission
NMFS = National Marine Fisheries Service
SHPO = State Historic Preservation Act
USACE = United States Army Corps of Engineers
USFWS = United States Fish and Wildlife Service

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Chapter 12
Study Conclusions and Recommendations

The five sites analyzed in this study (Yellowtail 5A, Seminoe 5A2, Seminoe 5A3, Seminoe 5C, and Trinity 5G2A) have an ability to generate power through energy arbitrage and ancillary services; however, none of the sites have positive net benefits under the base case scenario. The Yellowtail and Trinity sites show some potential if ancillary services would increase at unusually high escalation rates. All sites have geologic and environmental concerns that could increase costs or the difficulty of permitting and construction. Each site also requires some transmission infrastructure upgrades to transmit energy to demand centers. None of these sites are recommended to move forward for additional study at this time.

For the next steps in the process, the analysis is recommended to build on the lessons learned from this analysis to decrease costs or increase benefits from the projects. An initial screening effort could focus on these topics to try to narrow down a broad list of sites to a smaller list for more detailed evaluation:

- **Identify sites with a suitable L/H (operating head over water conductor length) ratio**. Finding a site that has a large elevation change at a short distance from the existing forebay reservoir would help reduce costs of the facilities.
- **Use large existing reservoirs**. The Operations Model found that pumped storage operations result in very small changes to water levels or volumes in the existing forebay reservoirs because the reservoirs are much larger than the proposed new reservoirs. Using a smaller reservoir would increase the likelihood that pumped storage operations could affect water supply for downstream environmental needs and water users.
- **Focus on sites in the Pacific Northwest, California, or Arizona**. These areas have a widespread transmission system that would help reduce the high transmission costs associated with the sites in this study. Additionally, ancillary service markets are likely to be established in these areas because of the focus on renewable energy.
- **Locate projects in areas with high potential for wind power development**. Pumped storage projects have maximum benefits when they can integrate with other renewable resources, such as wind power.

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Appendix A
Final Phase 1 Report

RECLAMATION
Managing Water in the West

Pumped Storage Evaluation Special Study

Yellowtail Forebay-Yellowtail Afterbay, Pathfinder-Alcova, Seminoe-Kortes, and Trinity-Lewiston Sites

Final Phase 1 Report

U.S. Department of the Interior
Bureau of Reclamation Power Resources Office
Denver, Colorado

May 2013

Mission Statements

The mission of the Department of the Interior is to protect and provide access to our Nation's natural and cultural heritage and honor our trust responsibilities to Indian Tribes and our commitments to island communities.

The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.

Pumped Storage Evaluation Special Study

Yellowtail Forebay-Yellowtail Afterbay, Pathfinder-Alcova, Seminoe Kortes, and Trinity-Lewiston Sites

Final Phase 1 Report

Prepared by

United States Department of the Interior
Bureau of Reclamation
Power Resources Office

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Denver, Colorado

May 2013

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Abbreviations and Acronyms

AF	acre-feet
AACE	American Association of Cost Estimators
cfs	cubic feet per second
CVP	Central Valley Project
CY	cubic yard
EIR	Environmental Impact Report
EPRI	Electrical Power Research Institute
ESA	Endangered Species Act
ft	feet
FERC	Federal Energy Regulatory Commission
GWh	gigawatt hour
GIS	Geographic Information System
H	static head
HVAC	heating, ventilation and air conditioning
kV	kilovolts
kW	kilowatts
L	conductor length
msl	mean sea level
MTFWP	Montana Fish, Wildlife, and Parks
MW	megawatts
MWH	megawatt hour
NEPA	National Environmental Policy Act
NPS	National Park Service
NRA	National Recreation Area
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
RPS	Renewable portfolio standard
TRRP	Trinity River Restoration Program
TW	tailwater
USFWS	United States Fish and Wildlife Service
USFS	United States Forest Service
WYGF	Wyoming Game and Fish
yr	year

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Executive Summary

Introduction

The Bureau of Reclamation (Reclamation) is the largest water supplier in the United States, owning and operating 188 projects across the western states with dams, reservoirs, canals, and other distribution infrastructure. Reclamation is the second largest producer of hydropower in the United States, behind the U.S. Army Corps of Engineers, , and owns and operates 53 hydropower plants that produce over 40,000,000 megawatt hours (MWh) of generation each year.. Reclamation is interested in the potential to use existing facilities to develop pump-generation projects. Pump-generation is recognized as one of the most useful methods for regulating intermittent renewable generation resources such as wind and solar. Reclamation has undertaken this Pumped Storage Evaluation Special Study to evaluate the potential of adding pump-generation at existing conventional hydropower stations. Reclamation initially identified four sites for the study due to their existing infrastructure which included existing upper and lower storage reservoirs, and existing power plant infrastructure and plans to do a more detailed analysis on two of the sites. The four sites include:

- Yellowtail - Yellowtail Dam and Yellowtail Afterbay are in south-central Montana in Reclamation's Great Plains Region. Yellowtail Dam, constructed on Bighorn River, forms Bighorn Lake, with a capacity of approximately 1.3 million acre-feet. Yellowtail Afterbay is 2.2 miles downstream from Yellowtail Dam, with a capacity of 3,140 acre-feet.
- Pathfinder - Pathfinder and Alcova reservoirs are on the North Platte River, southwest of Casper, Wyoming, in Reclamation's Great Plains Region. Pathfinder Reservoir has a total capacity of 1.0 million acre-feet. Alcova Dam in 10 miles downstream of Pathfinder Dam and has a total capacity of 184,208 acre-feet.
- Seminoe - Seminoe and Kortes reservoirs are on the North Platte River upstream of Pathfinder Reservoir in Reclamation's Great Plains Region. Seminoe Reservoir has a total capacity of 1.0 million acre-feet. Kortes Reservoir is 2 miles downstream of Seminoe Dam and has a capacity of 4,765 acre-feet.
- Trinity - Trinity and Lewiston reservoirs are on the Trinity River in northern California in Reclamation's Mid-Pacific Region. Trinity Reservoir has a storage capacity of 2.4 million acre-feet. Lewiston Dam is about 7 miles downstream of Trinity Dam and forms Lewiston Reservoir, which has a capacity of 14,660 acre-feet.

The study approach has been divided into two phases. Phase 1 of the study involves a preliminary screening level analysis of the above four sites to determine which two are selected for further study in a Phase 2 evaluation. Phase 2 of the study involves a conceptual-level feasibility study of the two selected sites.

The purpose of this report is to summarize the Phase 1 evaluation and results and to assist Reclamation with recommendations of two sites that should move forward for further study for potential conversion to pump-generation.

Screening Methodology

The Phase 1 evaluation includes the following steps for evaluating pump-generation potential at the four sites and recommending two sites for further study:

1. *Identify potential pump-generation options and complete preliminary sizing.* This step involves identifying a wide range of potential pump-generation options at each site. In addition to evaluating existing facilities at the four sites, this study also identifies potential new reservoirs that could serve as an upper reservoir for pump generation. Options were then sized based on existing active reservoir storage and volume, surrounding topography, historic lake elevations, dam characteristics and additional existing data.

2. *Screen identified options based on technical criteria for pump-generation projects.* After the initial list of options were identified and sized, the project team screened the options relative to criteria, such as conductor length (L)/static head (H) ratio, reservoir depth, minimum head/maximum head ratio and other physical and operating characteristics.

3. *Prepare preliminary cost opinions for selected options.* The project team completed preliminary cost opinions for the selected options in order to develop a relative comparison of costs among the options. Cost opinions were developed for major project elements.

4. *Conduct a fatal flaw analysis for operations, regulatory, environmental, and institutional constraints.* For those options that passed the technical screening, the project team collected information on operations criteria, regulatory setting, environmental resources, and existing stakeholder issues. The team evaluated each option relative for potential fatal flaws that could challenge development. If fatal flaws were identified, the option was precluded from further study.

5. *Assess the economic characteristics of options*. The economic evaluation is a cost effectiveness comparison and a qualitative evaluation of some economic characteristics, such as project location relative to an existing market for ancillary services and the potential for integration of renewable resources. The cost effectiveness analysis uses the estimated $/MW for each option as a comparison.

6. *Summarize evaluation results and recommend two sites for further evaluation.* The project team developed a summary table to compare how options perform relative to the technical, operations, environmental, regulatory, institutional, and economic criteria. Some options appeared to better meet the suite of criteria relative to other options. Based on the evaluation, the project team could make some recommendation as to which sites and options should move forward.

Concept Options Development and Technical Screening

Reclamation identified five potential design concepts for pump-generation projects that could be applied to the four sites. The concepts include the following, which are further defined in Section 2.1 of the report.

- Concept 1 - Replace existing units with new pump-generating sets.
- Concept 2 - Replace existing units with new pumping sets.
- Concept 3 - Add adjacent new pumping sets.
- Concept 4 - Add adjacent new pump-generating sets.
- Concept 5 - New reservoir and new pump-generating sets.

The project team screened out Concepts 1 and 2 because the associated loss in hydropower generation and effects to reservoir releases when taking the units offline for conversion. The team then identified 46 pump-generation options for Concepts 3, 4 and 5 at the four sites. For each site, the options were numbered relative to each of the Concepts 3, 4 and 5.

Figures ES-1 through ES-4 show the general locations for the 46 options at the four sites. Chapter 2 of the report includes detailed, topographic maps of the water conductors for each option and proposed new reservoirs under the Concept 5 options. The project team screened the above options on the following technical criteria:

- Maximum L/H ratio;
- Typical operating range of pump-turbine units (minimum head/maximum head);
- Reservoir depth at tie-in point;
- Energy storage (MWh);
- Resulting Installed Capacity (MW); and
- Estimated dam volume.

Figure ES-1. Yellowtail-Yellowtail Afterbay Site Option Locations

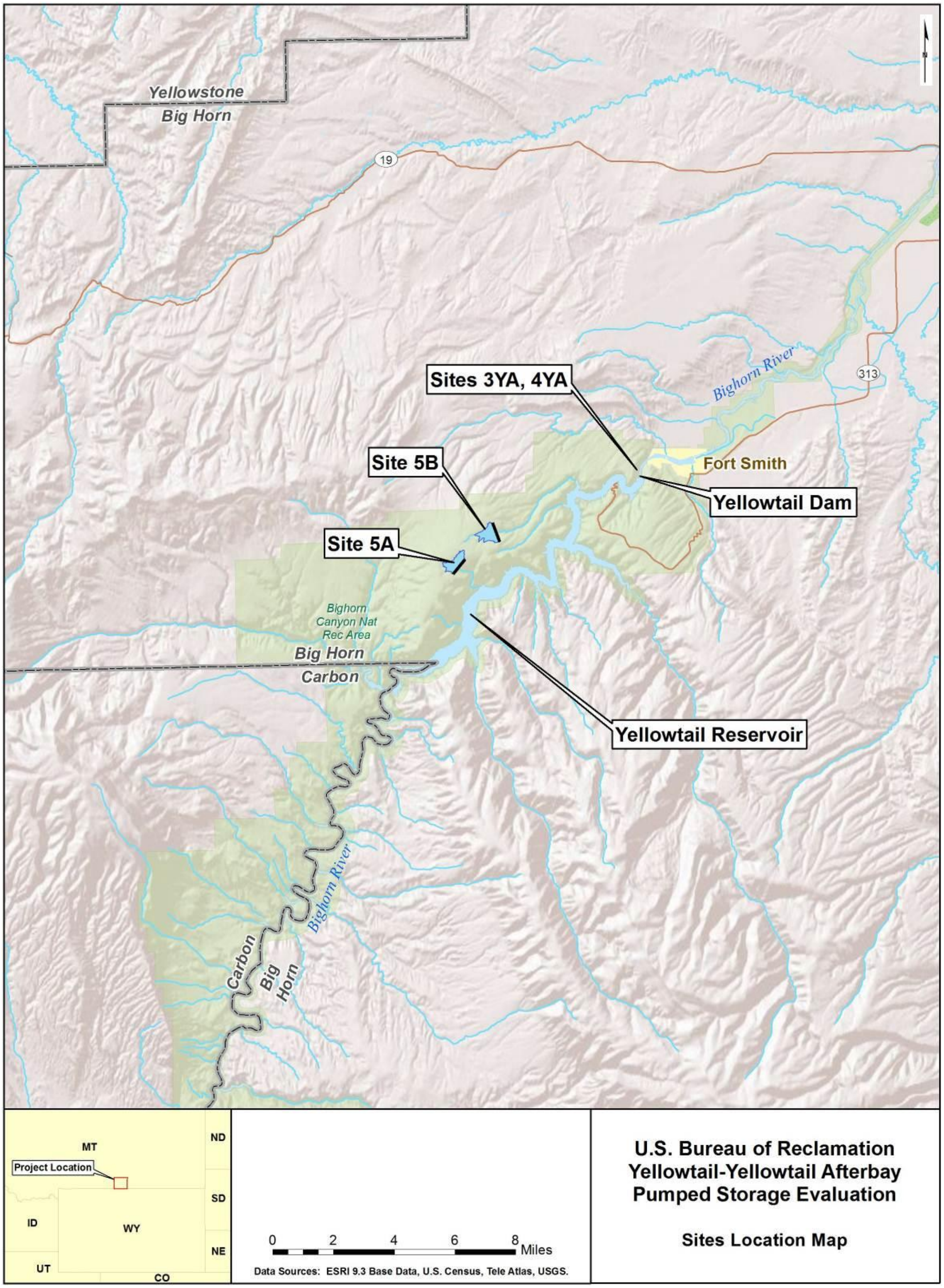


Figure ES-2. Pathfinder-Alcova Site Option Locations

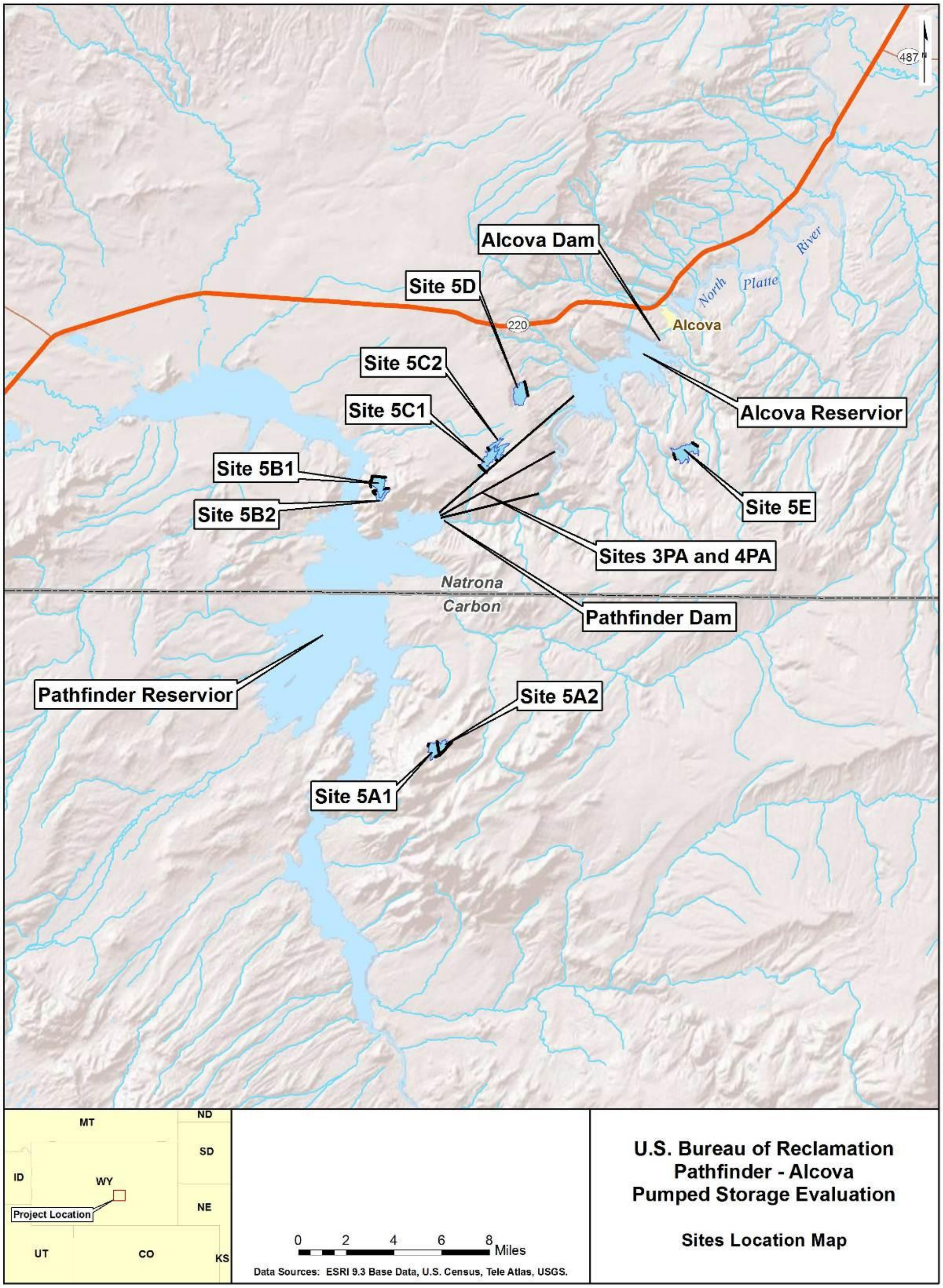


Figure ES-3. Seminoe-Kortes Site Option Locations

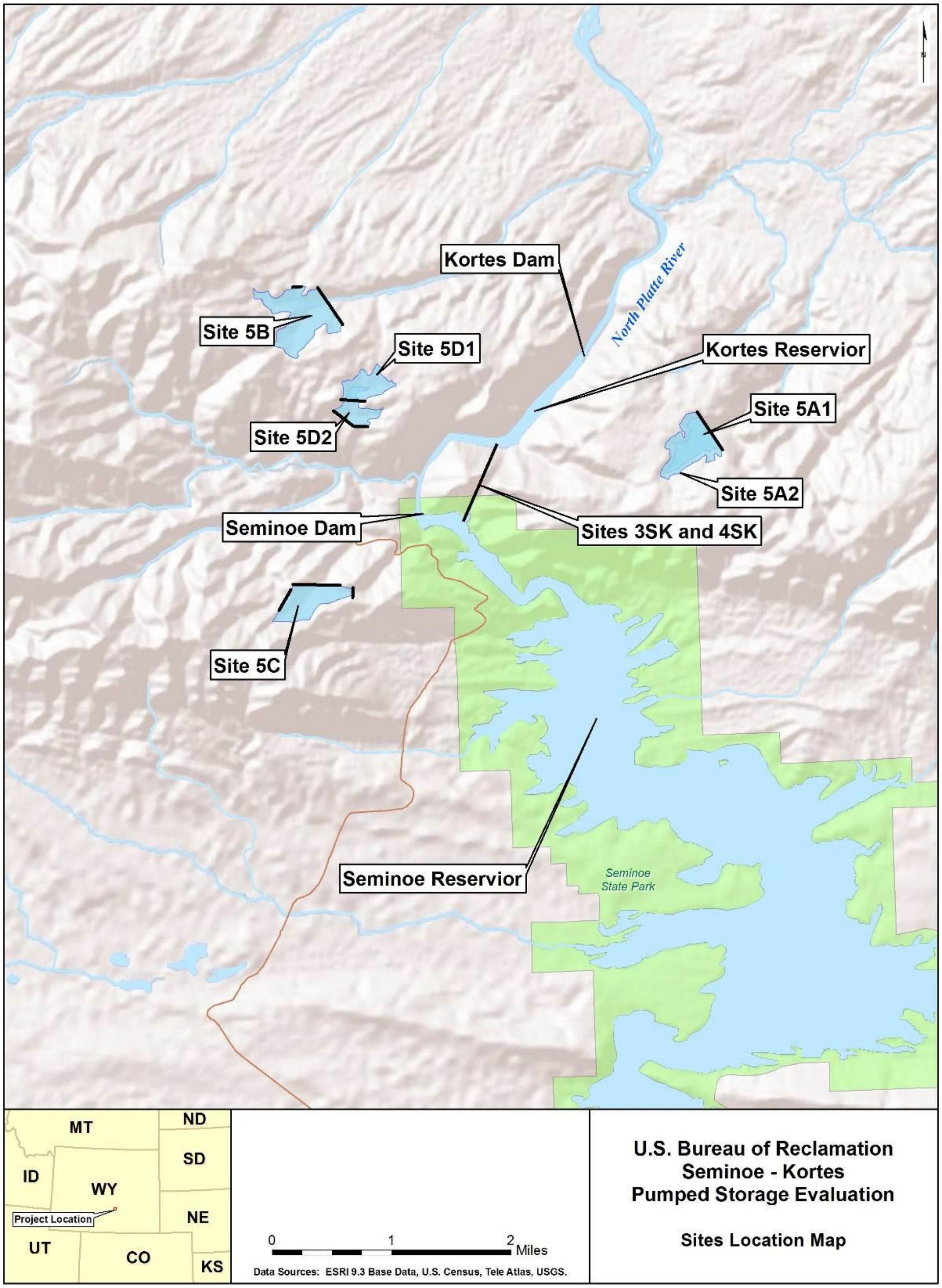
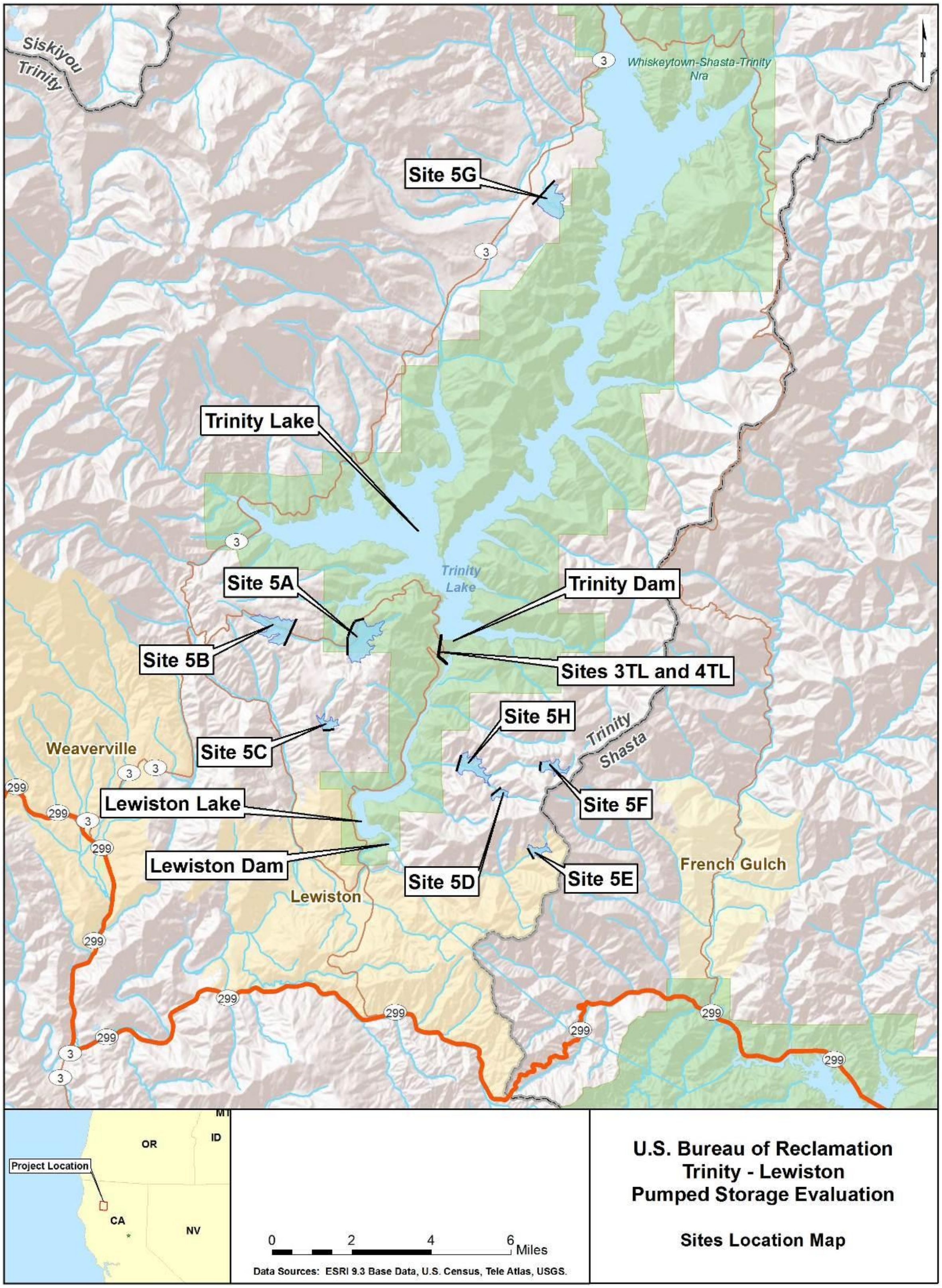


Figure ES-4. Trinity-Lewiston Site Option Locations



The team also dropped Concept 3 relative to Concept 4 options because the costs to install pump-generation sets would similar to pump sets, without providing any incremental increase in generation. Based on technical criteria above, the 46 options were screened down to 14 remaining options for further evaluation, including conceptual layouts, cost opinions, operational, regulatory and environmental screening, and an economic assessment. The technical evaluation is described in Chapter 2 of the report. Table ES-1 summarizes the 14 options remaining after technical screening.

Table ES-1. Selected Options Summary

Site	Option	Upper Reservoir	Lower Reservoir	Resulting Installed Capacity (MW)
Yellowtail	5A	New Reservoir 5A	Bighorn Lake	1,660
Yellowtail	5B	New Reservoir 5B	Bighorn Lake	1,607
Yellowtail	4YA-1	Bighorn Lake	Yellowtail Afterbay	112
Yellowtail	4YA-2	Bighorn Lake	Yellowtail Afterbay	54
Pathfinder	5A1	New Reservoir 5A1	Pathfinder	575
Pathfinder	5D	New Reservoir 5D	Alcova	708
Seminoe	5A1	New Reservoir 5A1	Kortes	277
Seminoe	5A2	New Reservoir 5A2	Seminoe	773
Seminoe	5C	New Reservoir 5C	Seminoe	572
Seminoe	5D1	New Reservoir 5D1	Kortes	266
Trinity	5A-B	New Reservoir 5A-B	Trinity	765
Trinity	5F	New Reservoir 5F	Lewiston	615
Trinity	5G2-A	New Reservoir 5G2-A	Trinity	1,024
Trinity	4TL	Trinity	Lewiston	111

Evaluation Summary and Comparison

For further screening analysis, the project team developed Class 5 cost opinions for major project elements. The team also developed qualitative evaluation criteria for operations, environmental, and institutional characteristics. The project team then evaluated each of the options relative to the criteria to determine if there could be a fatal flaw.

Table ES-2 summarizes the options evaluation relative to the quantitative and qualitative criteria. The quantitative criteria are listed first and show the project capacity and costs. Table ES-2 also includes a ranking of cost/MW installed capacity for all the options. The qualitative criteria are listed below the quantitative criteria with the appropriate color ratings for each option. For the qualitative criteria, options with more green ratings generally perform better relative to the criteria than with more yellow ratings. A red rating indicates a fatal flaw and that the option should not be further evaluated. Chapter 5 of the report details the screening analysis and explains why options received each rating relative to each criterion.

Table ES-2. Option Evaluation and Comparison

Site	Yellowtail	Yellowtail	Yellowtail	Yellowtail	Pathfinder	Pathfinder	Seminoe	Seminoe	Seminoe	Seminoe	Trinity	Trinity	Trinity	Trinity
Option	**5A**	**5B**	**4YA-1**	**4YA-2**	**5A1**	**5D**	**5A1**	**5A2**	**5C**	**5D1**	**5A-B**	**5F**	**5G2-A**	**4TL**
Upper Reservoir	New Reservoir 5A	New Reservoir 5B	Bighorn Lake	Bighorn Lake	New Reservoir 5A1	New Reservoir 5D	New Reservoir 5A1	New Reservoir 5A2	New Reservoir 5C	New Reservoir 5D1	New Reservoir 5A-B	New Reservoir 5F	New Reservoir 5G2-A	Trinity
Lower Reservoir	Bighorn Lake	Bighorn Lake	Yellowtail Afterbay	Yellowtail Afterbay	Pathfinder	Alcova	Kortes	Seminoe	Seminoe	Kortes	Trinity	Lewiston	Trinity	Lewiston
Technical Screening														
Upper Reservoir Usable Vol (acre-ft)	12,081	13,509	2,875	1,413	5,297	12,950	3,068	10,119	7,145	2,689	13,697	3,109	15,022	3,154
Lower Reservoir Usable Vol (acre-ft)	336,103	336,103	2,875	1,413	985,102	30,603	3,073	985,603	985,603	3,073	1,859,688	3,154	1,859,688	3,154
Approx. Static Head (ft) (<2650 ft)	1,562	1,352	444	431	1,232	621	1,025	869	909	1,126	635	2,248	775	401
Assumed Usable Storage Volume	12,081	13,509	2,875	1,413	5,297	12,950	3,068	10,119	7,145	2,689	13,697	3,154	15,022	3,154
Assumed Hours of Storage	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Resulting Installed Capacity (MW)	1,660	1,607	112	54	575	708	277	773	572	266	765	615	1,024	111
Energy Storage (MWh)	16,601	16,067	1,123	536	5,745	7,082	2,767	7,734	5,715	2,664	7,654	6,151	10,245	1,112
Estimated Dam Volume (CY)	7,734,313	6,499,188	NA	NA	3,671,836	5,716,670	4,688,429	9,756,673	8,430,094	1,899,238	7,837,254	2,990,932	4,025,634	NA
Maximum Dam Height (ft) (<400 ft)	298	261	NA	NA	231	269	297	397	336	216	377	278	139	NA
L/H Ratio (Guideline)	5 (<12)	6 (<12)	6 (<7)	6 (<7)	9 (<12)	14 (<10)	7 (<12)	8 (<12)	7 (<12)	5 (<12)	15 (<12)	10 (<12)	9 (<12)	11 (<7)
Typical Operating Range of Pumps (70-100%)	86%	85%	78%	82%	84%	79%	88%	81%	80%	85%	72%	98%	71%	70%
Cost Opinions														
Construction Cost (million)	$2,081	$2,141	$233	$133	$1,251	$1,696	$860	$1,765	$1,235	$664	$1,862	$1,223	$1,885	$256
$/MW Installed Capacity (million)	$1.25	$1.33	$2.07	$2.48	$2.18	$2.39	$3.11	$2.28	$2.16	$2.49	$2.43	$1.99	$1.84	$2.31
Cost Ranking based on $/MW	1	2	5	12	7	10	14	8	6	13	11	4	3	9
Operations Criteria														
Meet Reservoir Elevation/Storage Requirements	Green	Green	Yellow	Yellow	Green	Green	Green	Green	Green	Green	Green	Green	Green	Yellow
Meet Minimum Flow Release Requirements	Green	Green	Yellow	Yellow	Green	Green	Green	Green	Green	Green	Green	Yellow	Green	Yellow
Meet Water Quality/Temperature Requirements	Green	Green	Red	Green	Green	Green	Yellow	Green	Green	Yellow	Green	Yellow	Green	Yellow
Require More System Reoperation	Green	Green	Green	Green	Green	Yellow	Yellow	Green	Green	Yellow	Green	Yellow	Green	Green
Environmental, Regulatory, and Institutional Criteria														
Fisheries Impacts	Green	Green	Yellow	Yellow	Green	Green	Yellow	Green	Green	Yellow	Green	Yellow	Green	Yellow
Special Status Species/Critical Habitat Impacts	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Yellow	Yellow	Green	Yellow
Recreation Impacts	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green
Cultural and Historic Resources Impacts	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green
Native American Resources Impacts	Yellow	Yellow	Green	Green	Green	Green	Green	Green	Green	Green	Green	Yellow	Green	Yellow
Land Use/Regulatory Designation Impacts	Yellow	Yellow	Yellow	Yellow	Green	Green	Yellow	Yellow	Yellow	Green	Yellow	Yellow	Yellow	Yellow
Construction Impacts	Yellow	Yellow	Green	Green	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Green
Stakeholders Issues/Conflicts	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow

Qualitative Criteria Rating Scale:
"Green" indicates effects can likely be coordinated, avoided, or mitigated
"Yellow" indicates effects might pose challenges, but is not fatal flaw at this point in the analysis
"Red" indicates effects are a potential fatal flaw to the development of alternative

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Not shown in the table, but some important economic considerations for selecting options to move forward are the existence of an operational ancillary services market, availability for renewable energy integration, available high voltage transmission capacity and grid impacts, demand for power in the region, available pump-back power, access, distance from the load centers and constructability (including challenges associated with tapping into an existing reservoir). The Trinity site is in northwest California, which has an emerging market for ancillary services, relative to Yellowtail, Pathfinder, and Seminoe sites in Montana and Wyoming, where there is no developed ancillary services market at this time. Montana and Wyoming, particularly, have opportunities for development of wind power, which can integrate into a pump-generation project, and then possibly spur the development of an ancillary services market.

This analysis estimates transmission costs to the closest substation and does not evaluate further transmission or necessary upgrades to the power grid. For example, there are known transmission capacity limitations at the Yellowtail site, which would need to be addressed in order to use the power generated by the options. Related to transmission capacity, it is also important to assess customer demands and whether there is a need for some of these large capacity options. The Yellowtail Options 5A and 5B both have energy storage of approximately 16,000 MWh. Energy storage for the Pathfinder and Seminoe sites range from 2,700 to 9,500 MWh and energy storage at the Trinity site ranges from 1,112 MWh for the Concept 4 option to 10,245 MWh for Trinity Option 5G2-A. Some of these large capacity options may be able to service multiple markets, which would add to the value of the pump-generation project.

Recommendations

Based on the results of this study, the project team recommends the following options for further study: Yellowtail 5A, Yellowtail 5B and Trinity 5G2-A. These options have similar environmental and regulatory challenges that will need to be addressed in future planning efforts.

Yellowtail 5A and 5B are close enough in proximity that they can be further evaluated as one site. The project team recommends that Reclamation consider evaluating Yellowtail 5A and 5B during the Phase 2 evaluation, with several caveats for consideration. Reclamation should understand transmission limitations and potential impacts to the grid. The scope of this study considers transmission to the closest substation and does not include grid impacts. Further investigation of transmission capacity could also indicate whether or not there is a customer need for all the potential power generated. The Yellowtail 5A and 5B could produce up to 16,600 MWh, which could be more than the regional demand. A second caveat is that the proposed new reservoir sites are on tribal holdings. Reclamation should consider the existing relationship with the Crow Tribe and whether they could pursue a partnership with the tribe or compensate the tribe for the land. Either path would likely lead to higher project costs. The

Yellowtail options are approximately $500,000/MW less than the next closest options in terms of costs; therefore, additional tribal coordination costs may not change the overall cost ranking of the options.

The project team also recommends that the Trinity Option 5G2-A be considered for additional studies. This cost per MW for this option is estimated to be $1.84 million/MW, which is considered near the range as a feasible pump-generation project. This proposed new reservoir is at the upstream end of the existing Trinity Reservoir and would likely have fewer issues with TRRP and CVP operations. California also has a more developed ancillary services market, which would add to the economic benefits of the project and make it more economically viable based on costs and benefits. California also has more challenging environmental issues that could prevent construction of new reservoir. A detailed operations analysis of Trinity site could also help inform Reclamation of the potential feasibility of Trinity Option 4TL, which would avoid construction of a new reservoir and use the existing forebay and afterbay.

In addition to the Yellowtail and Trinity options, further study of a Wyoming site would be beneficial because of the wind development potential and the need for energy storage. Both the Seminoe 5C and 5A2 sites offer the most development potential and could be further evaluated in the Phase 2 Study effort.

Reclamation should continue to evaluate the market demand for power in these sites and their other service areas. Preliminary research in this Phase 1 evaluation has shown that local utilities are in need of increased generation to meet growing demands. Furthermore, utilities are also in need of bulk storage to integrate wind and other renewable resources into the utility grid. Transmission capacity and infrastructure is also an important factor in assessing site viability to determine if power produced in remote rural areas can be delivered to the urban load centers. These topics will be further investigated in the Phase 2 evaluation.

Reclamation should also assess whether there are other existing forebays and afterbays in their entire service area that may have pump-generation potential or another area where a new reservoir could serve pump-generation and other needs. This Phase 1 evaluation has established a process to identify and screen potential options for pump-generation.

Chapter 1
Introduction

1.1 Background

The Bureau of Reclamation (Reclamation) is the largest water supplier in the United States, owning and operating 188 projects across the western states with dams, reservoirs, canals, and other distribution infrastructure. Reclamation is the second largest producer of hydropower in the United States, behind the Army Corps of Engineers, and owns and operates 53 hydropower plants that produce over 40,000,000 megawatt hours (MWh) of generation each year.. Reclamation is interested in the potential to use existing facilities to develop pump-generation projects. Pump-generation is recognized as one of the most useful methods for regulating intermittent renewable generation resources such as wind and solar.

Reclamation has undertaken this Pump Storage Analysis Study to evaluate the potential of adding pump-generation at existing conventional hydropower stations. Reclamation initially identified four sites for the study due to their existing infrastructure which included existing upper and lower storage reservoirs, and existing power plant infrastructure and plans to do a more detailed analysis on two of the sites. Therefore, the study approach has been divided into two phases. Phase 1 of the study involves a preliminary screening level analysis of the four sites to determine which two are selected for further study in a Phase 2 evaluation. Phase 2 of the study involves a conceptual-level feasibility study of the two selected sites.

1.2 Purpose of this Report

The purpose of this report is to summarize the Phase 1 evaluation and results to recommend two sites that should move forward for further study for potential conversion to pump-generation. This study does not represent a feasibility level investigation.

1.3 Sites Identified for Study

Reclamation initially identified four existing sites for a potential pump-generation project. Each site includes two reservoirs, existing power complexes and infrastructure. The sites are described below.

1.3.1 Yellowtail Dam (Bighorn Lake) and Yellowtail Afterbay

Yellowtail Dam and Yellowtail Afterbay are in south-central Montana in Reclamation's Great Plains Region. Yellowtail Dam, constructed on Bighorn River, forms Bighorn Lake, which has a surface area of 17,300 acres, a length of 72 miles and a total capacity of approximately 1.3 million acre-feet. Yellowtail Powerplant, which lies at the toe of Yellowtail Dam, has an installed capacity of 250 megawatts (MW). The powerplant has been in operation since 1966. Yellowtail Afterbay Dam is 2.2 miles downstream from Yellowtail Dam. The dam forms Yellowtail Afterbay with a capacity of 3,140 acre-feet. Discharges are used to provide a uniform daily flow into Bighorn River, leveling the peaking power discharges from Yellowtail Powerplant.

1.3.2 Pathfinder Reservoir and Alcova Reservoir

Pathfinder and Alcova reservoirs are on the North Platte River, southwest of Casper, Wyoming, in Reclamation's Great Plains Region. Pathfinder Reservoir has a total capacity of 1.0 million acre-feet. The Freemont Canyon Powerplant, on the North Platte River at the head of Alcova Reservoir, generates power during water releases from Pathfinder Reservoir. Water is conveyed to the powerplant through a three-mile long tunnel. The powerplant has an installed capacity of 66.8 MW and began operations in 1960. Alcova Dam in 10 miles downstream of Pathfinder Dam and has a total capacity of 184,208 acre-feet. Alcova Powerplant generates power from releases at Alcova Dam. The powerplant has an installed capacity of 41.4 MW and began operations in 1955.

1.3.3 Seminoe Reservoir and Kortes Reservoir

Seminoe and Kortes reservoirs are on the North Platte River upstream of Pathfinder Reservoir in Reclamation's Great Plains Region. Seminoe Reservoir has a total capacity of 1.0 million acre-feet. Seminoe Powerplant is at the base of the dam and has an installed capacity of 51.75 MW. The initial year of operation for the powerplant was 1939. Kortes Reservoir is 2 miles downstream of Seminoe Dam and has a capacity of 4,765 acre-feet. Water released from Seminoe Dam to Pathfinder Reservoir passes through the Kortes Powerplant to generate power. The powerplant has an installed capacity of 36 MW and began operations in 1950.

1.3.4 Trinity Reservoir and Lewiston Reservoir

Trinity and Lewiston reservoirs are on the Trinity River in northern California in Reclamation's Mid-Pacific Region. Trinity Reservoir has a storage capacity of 2.4 million acre-feet. Trinity Powerplant is a peaking facility with an installed capacity of 140 MW. The powerplant began operations in 1964. Lewiston Dam is about 7 miles downstream of Trinity Dam and forms Lewiston Reservoir, which has a capacity of 14,660 acre-feet. Lewiston Powerplant is as the base of Lewiston Dam. The powerplant has an installed capacity of 250 kilowatts (kW) and began operations in 1964.

1.4 Phase 1 Evaluation Methodology

As described above, Reclamation initially identified four sites for potential conversion to a pump-generation project. The objective of the Phase 1 evaluation is to narrow the four sites to two sites that should be further evaluated for potential conversion. The Phase 1 evaluation includes the following steps for evaluating pump-generation potential at the four sites and recommending two sites for further study:

1. *Identify potential pump-generation options and complete preliminary sizing.* This step involves identifying a wide range of potential pump-generation options at each site. In addition to evaluating existing facilities at the four sites, this study also identifies potential new reservoirs that could serve as an upper reservoir for pump generation. Options were then sized based on existing active reservoir storage and volume, surrounding topography, historic lake elevations, dam characteristics and additional existing data.

2. *Screen identified options based on various technical criteria for pump-generation projects.* After the initial list of options were identified and sized, the project team screened the options relative to technical criteria, such as conductor length (L)/static head (H) ratio, reservoir depth, minimum head/maximum head ratio and other physical and operating characteristics.

3. *Prepare preliminary cost opinions for selected options.* The project team completed preliminary cost opinions for the selected options in order to develop a relative comparison of costs among the options. Cost opinions were developed for major project elements assuming single-speed technology. It should be noted that single-speed versus variable-speed technology will be addressed in the Phase 2 evaluation. For the purpose of the initial screening , the unit technology type has no impact on site ranking results.

4. *Conduct a fatal flaw analysis for operations, regulatory, environmental, and institutional constraints.* For those options that passed the technical screening, the project team collected information on operations criteria, regulatory setting, environmental resources, and existing stakeholder issues. The team evaluated each option relative for potential fatal flaws that could challenge development. If fatal flaws were identified, the option was precluded from further study.

5. *Assess the economic characteristics of options.* The economic evaluation is a cost effectiveness comparison and a qualitative evaluation of some economic characteristics, such as project location relative to an existing market for ancillary services and the potential for integration of renewable resources. The

cost effectiveness analysis uses the estimated $/MW for each option as a comparison.

6. *Summarize evaluation results and recommend two sites for further evaluation.* The project team developed a summary table to compare how options perform relative to the technical, operations, environmental, regulatory, institutional, and economic criteria. Some options appeared to better meet the suite of criteria relative to other options. Based on the evaluation, the project team could make some recommendation as to which sites and options should move forward.

1.5 Report Contents

In addition to this Introduction, this report includes the following chapters:

- **Chapter 2 Concept Option Identification, Preliminary Sizing, and Technical Screening –** discusses how a wide range of pump-generation options were initially identified and the first screening step to narrow the options.
- **Chapter 3 Conceptual Layout and Cost Evaluation Studies –** presents conceptual layouts for the remaining options and how facility costs were evaluated.
- **Chapter 4 Cost Opinions and Project Schedule –** presents the cost opinions, including total construction costs, for each option and a schedule for implementation.
- **Chapter 5 Operations, Regulatory, and Environmental Screening and Economic Evaluation –** presents the methods and results for the operations, regulatory and environmental screening and the economic evaluation.
- **Chapter 6 Summary and Recommendation –** summarizes the results of the Phase 1 evaluation and makes recommendations for sites to move forward.
- **Chapter 7 References –** lists the references used in development of this report.

Chapter 2 Concept Option Identification, Preliminary Sizing, and Technical Screening

This chapter defines general pump-generation concepts and describes how the initial options for each concept were identified and evaluated. Multiple options were developed at each of the four sites – Yellowtail, Pathfinder, Seminoe, and Trinity. This chapter also presents the results of the first screening step to identify the options to be carried forward for cost opinions, operations, environmental, regulatory, and economic screening.

2.1 Pump Generation Design Concepts

Reclamation identified five potential design concepts for pump-generation projects that could be applied to the four sites. The concepts are described below.

- ***Concept 1 - Replace existing units with new pump-generating sets.*** Under this concept, one or more existing generation units would be converted to pump-generation units. The concept would maintain the total generation capacity of the existing powerplant but allow pumping from the afterbay back into the forebay for reuse. This concept would utilize the existing forebay and afterbay capabilities.
- ***Concept 2 - Replace existing units with new pumping sets.*** Under this concept, one or more existing generation units would be replaced with pump-back units. This concept would reduce the total generation capacity of the powerplant. This concept would utilize the existing forebay and afterbay capabilities.
- ***Concept 3 - Add adjacent new pumping sets.*** Concept 3 includes the addition of an independent a pumping plant to an existing generation facility to return water from the afterbay to the forebay. This approach would maintain all of the generation capacity and operation of the existing powerplant. This concept utilizes the existing forebay and afterbay, but requires construction of new a pumping plant, conveyance and other appurtenant facilities and equipment.
- ***Concept 4 - Add adjacent new pump-generating sets.*** Concept 4 includes the addition of an independent pump-generation system to an existing generation facility. All of the existing generation capacity at the powerplant is maintained, and pump-generation capability is added. This design concept uses the existing forebay and afterbay, but requires construction of new penstocks and other facilities.

- ***Concept 5 - New reservoir and new pump-generating sets.*** Concept 5 includes the construction of a new upper reservoir to serve a forebay. An existing reservoir would be used as an afterbay. This concept requires a pump-turbine system, a new (upper) reservoir and other appurtenant facilities and equipment.

Concepts 1 and 2 would require the existing generating units to be taken offline for a substantial period of time (during unit conversion) negatively impacting the Reclamation’s ability to produce power and perhaps adhere to minimum downstream flow releases. In addition, the conversion of conventional generating units to either pumps or pump-turbines would require a unit derating due to the required submergence of the pumps or pump-turbine. The project team decided that the associated loss in hydropower generation and effects to reservoir releases would prevent Reclamation from meeting its existing commitments and therefore considered a fatal flaw. Therefore, Concepts 1 and 2 were dropped and not further evaluated in this study. The project team found no fatal flaws with Concepts 3 through 5, and continued with an evaluation of each concept at the four project sties.

2.2 Site Data Collection

The project team collected and reviewed data for each site to begin defining options for Concepts 3, 4 and 5. The following information for each of the eight existing reservoirs at the project sites was needed:

- Surrounding Topography (GIS)
- Top of Active Reservoir Storage (feet [ft])
- Top of Inactive Reservoir Storage (ft)
- Active Reservoir Volume (ft)
- Dam Crest Elevation (ft)
- Existing Powerplant Installed Capacity (MW)
- Historical Lake Elevations (ft)

This information is summarized within project profiles in Figures 2-1 through 2-3. For some reservoirs, the actual top of inactive storage differs from the assumed top of inactive storage. The project team based the assumed top of inactive storage on the historical lake elevations. If historic lake elevations did not tend to decrease all the way to the actual top of inactive storages, the project team assumed a higher elevation so that the project would not decrease lake levels past historic elevations. Figures 2-4 through 2-11 show the historical lake elevations for each reservoir.

Figure 2-1. Yellowtail-Yellowtail Afterbay Project Profile

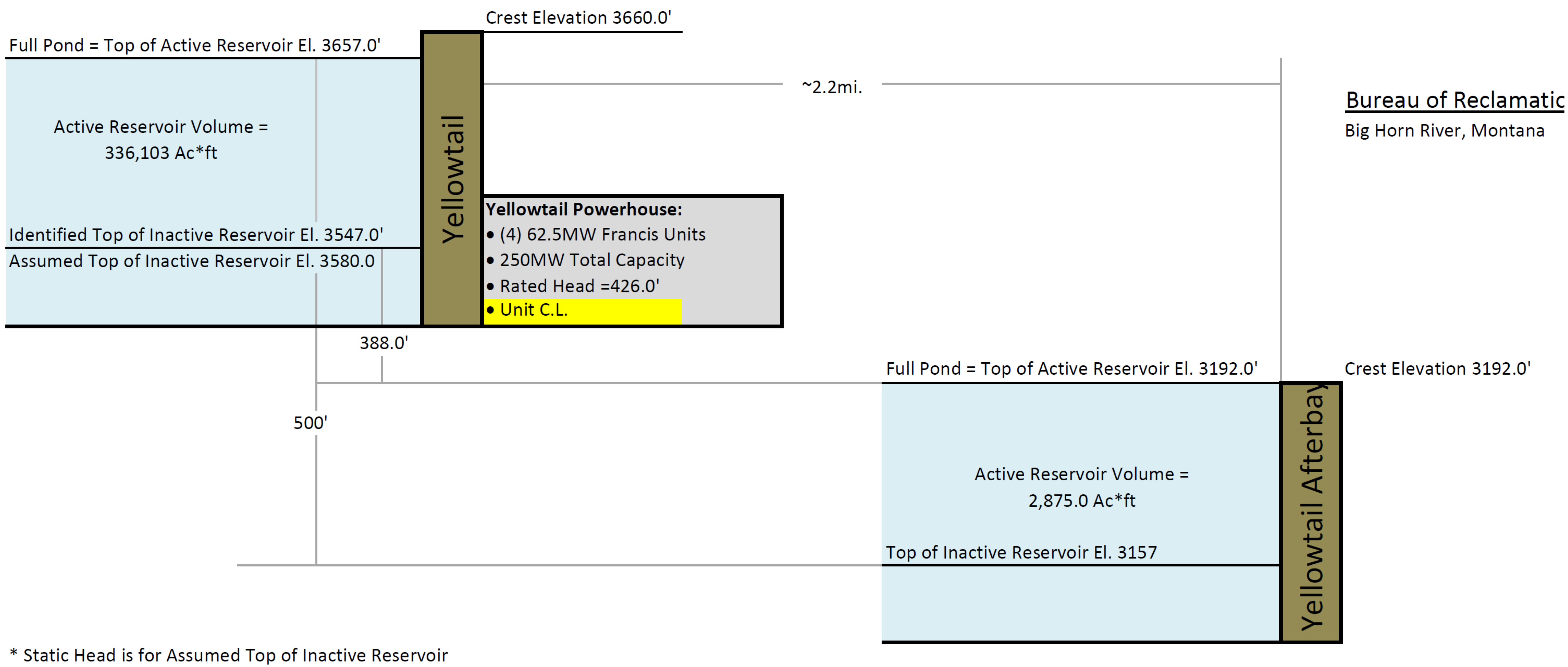

Figure 2-2. Seminoe-Kortes and Pathfinder-Alcova Project Profile

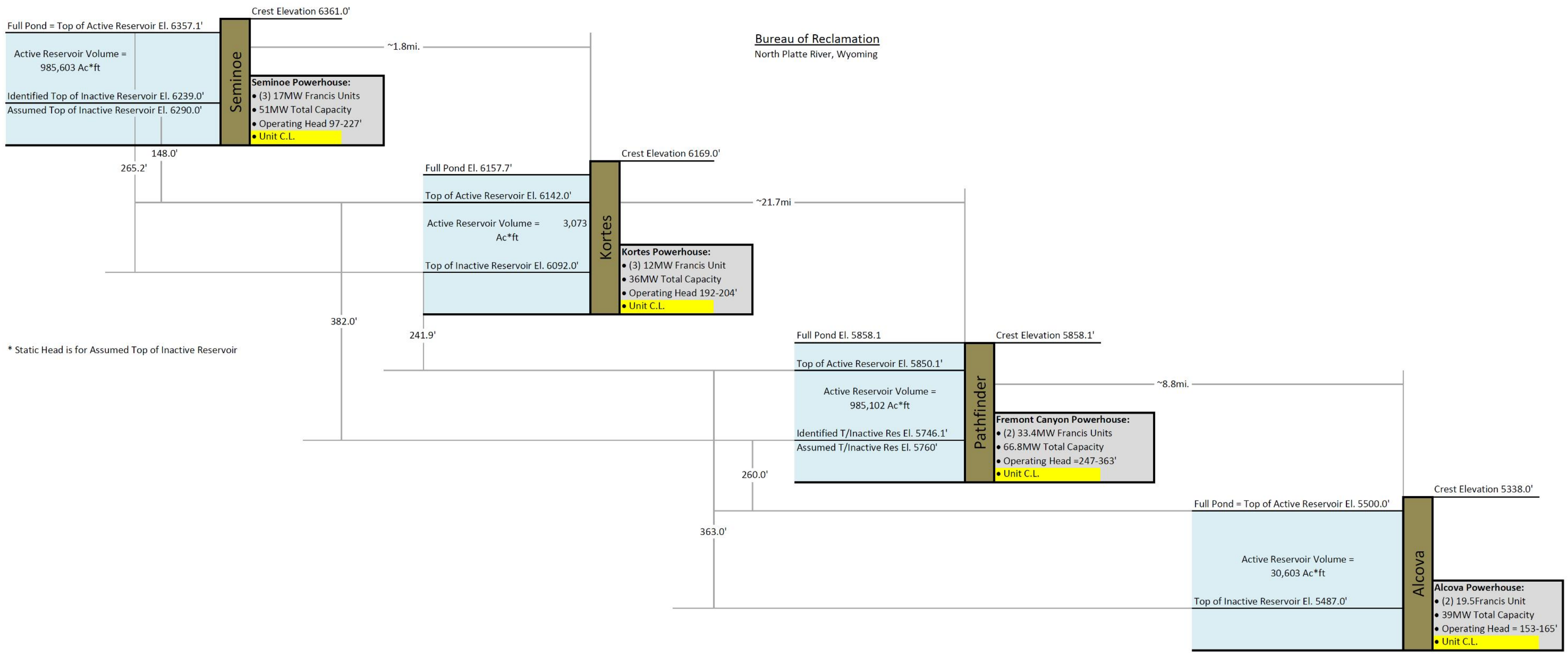

Figure 2-3. Trinity-Lewiston Project Profile

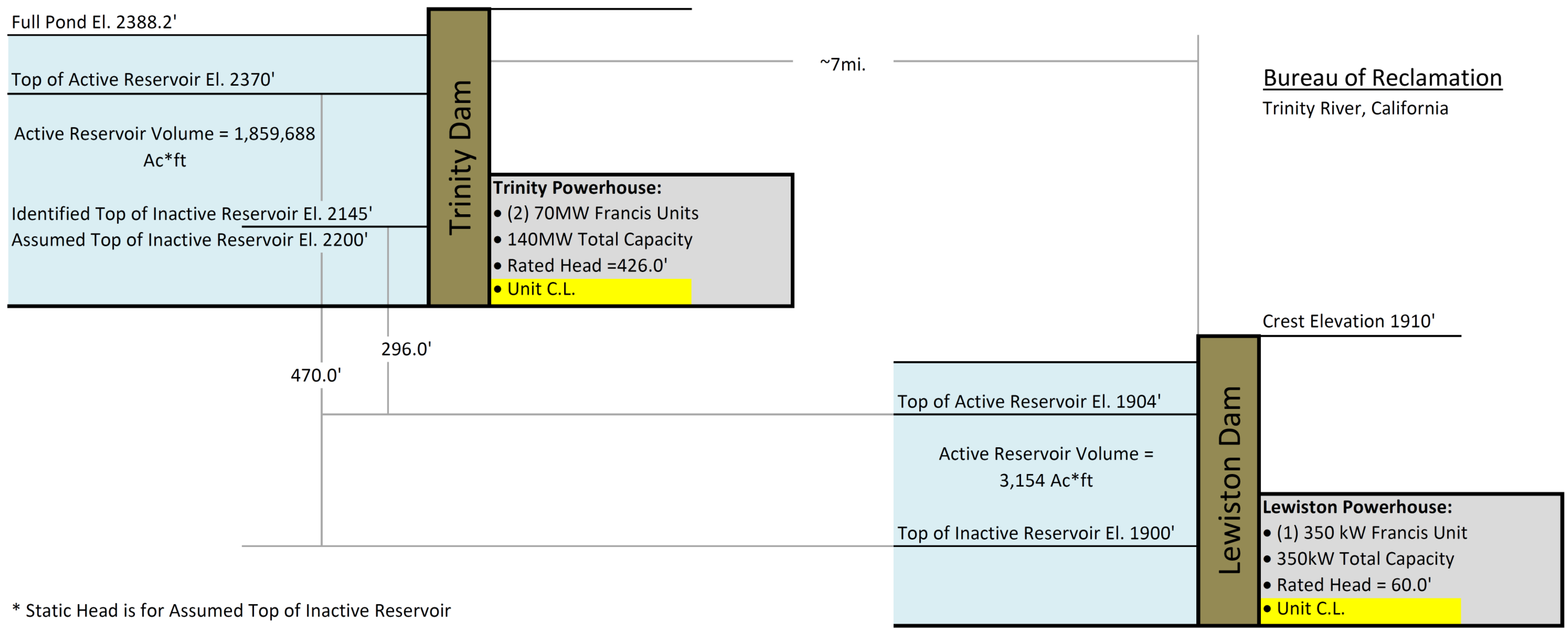

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Figure 2-4. Yellowtail Historic Lake Level Elevations

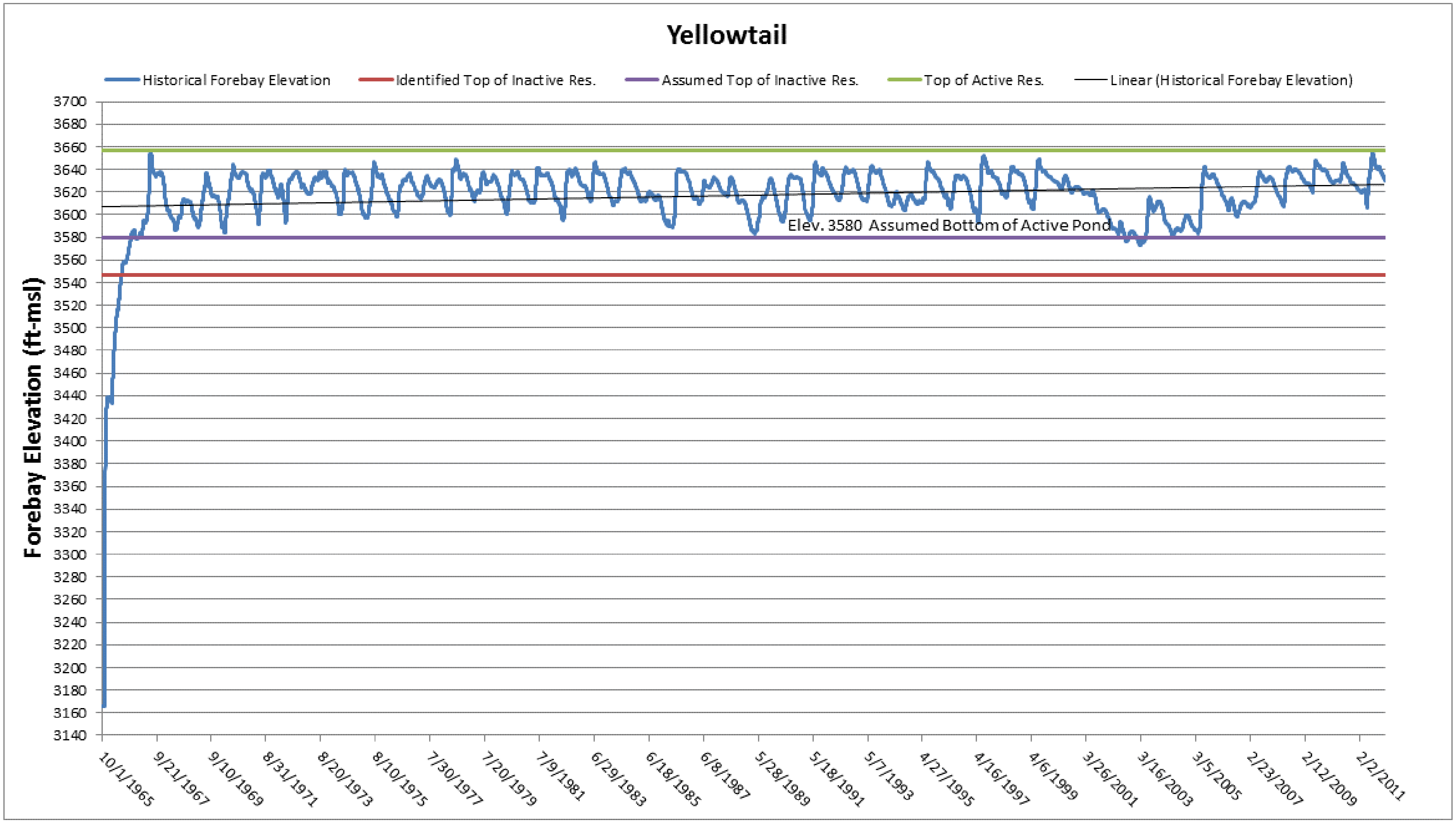


Figure 2-5. Yellowtail Afterbay Historic Lake Level Elevations

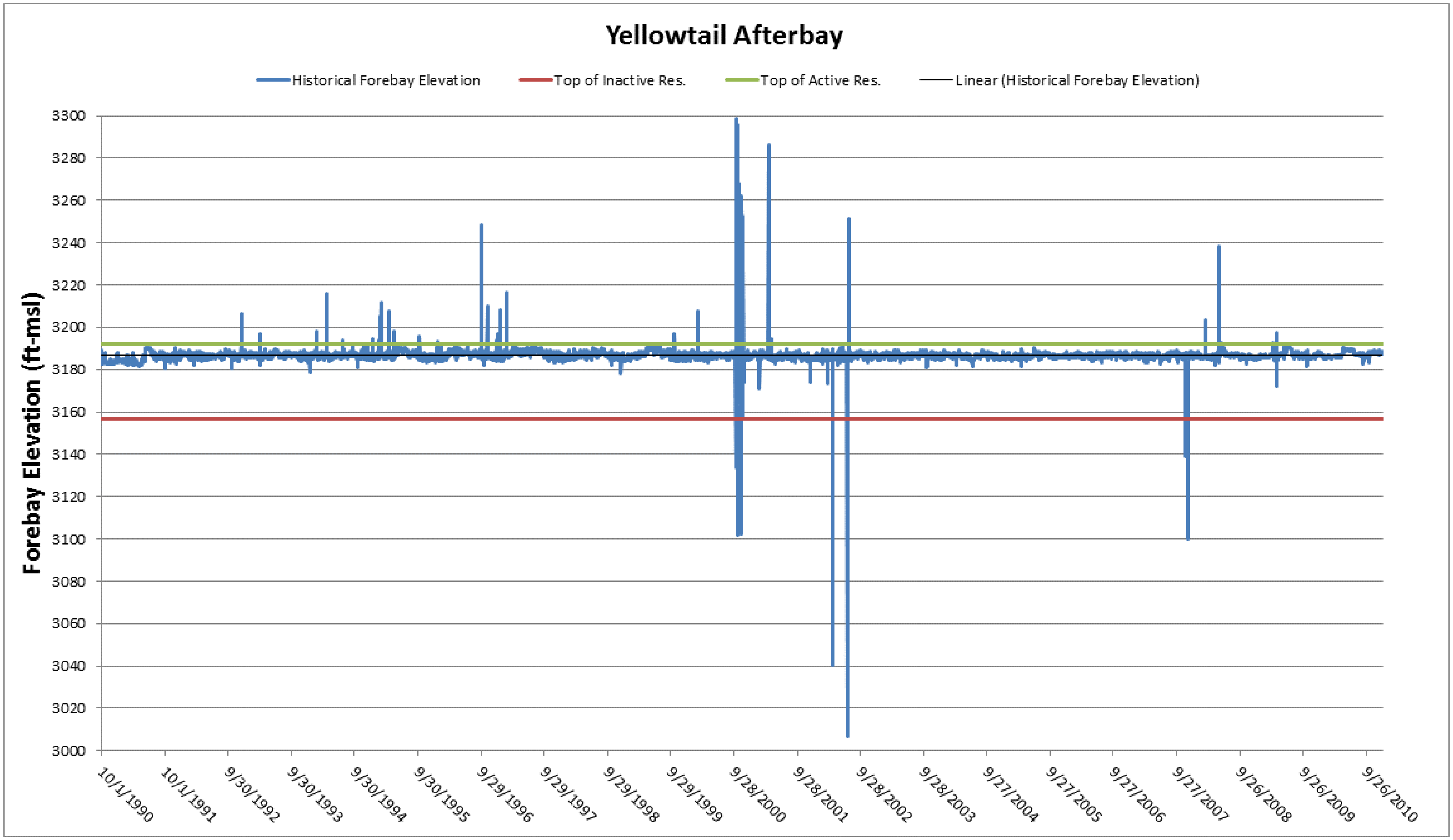


Figure 2-6. Pathfinder Historic Lake Level Elevations

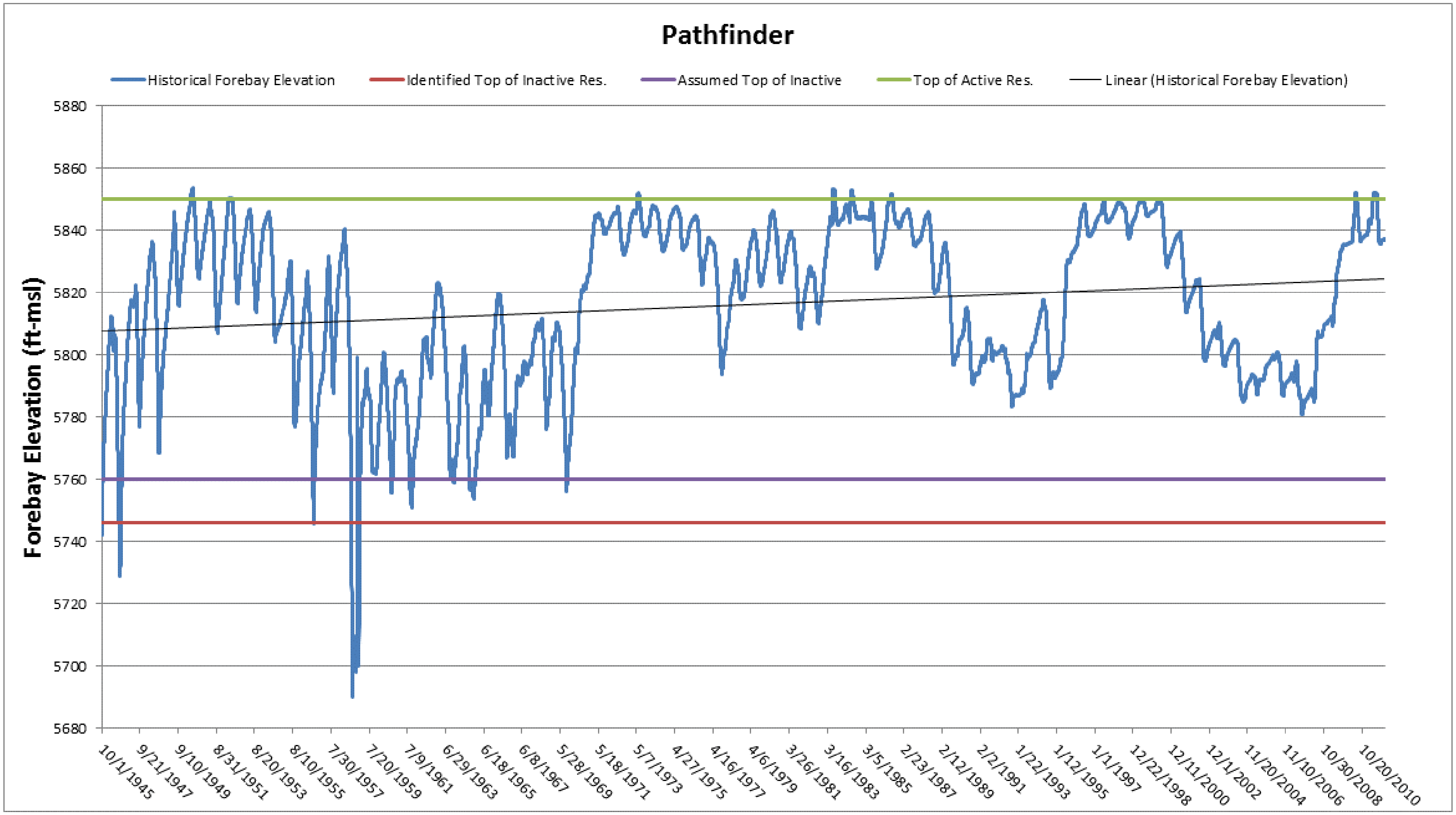


Figure 2-7. Alcova Historic Lake Level Elevations

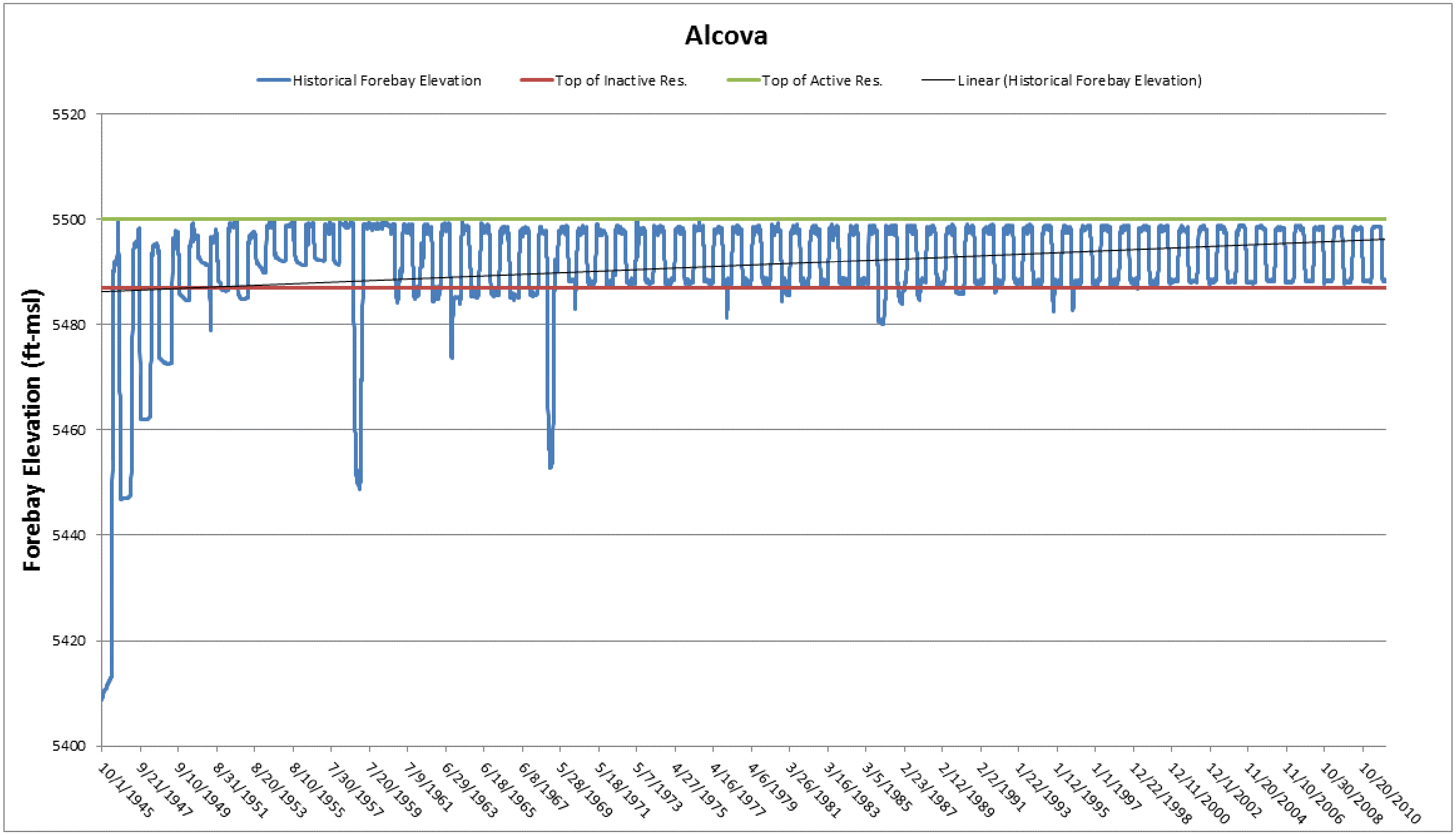


Figure 2-8. Seminoe Historic Lake Level Elevations

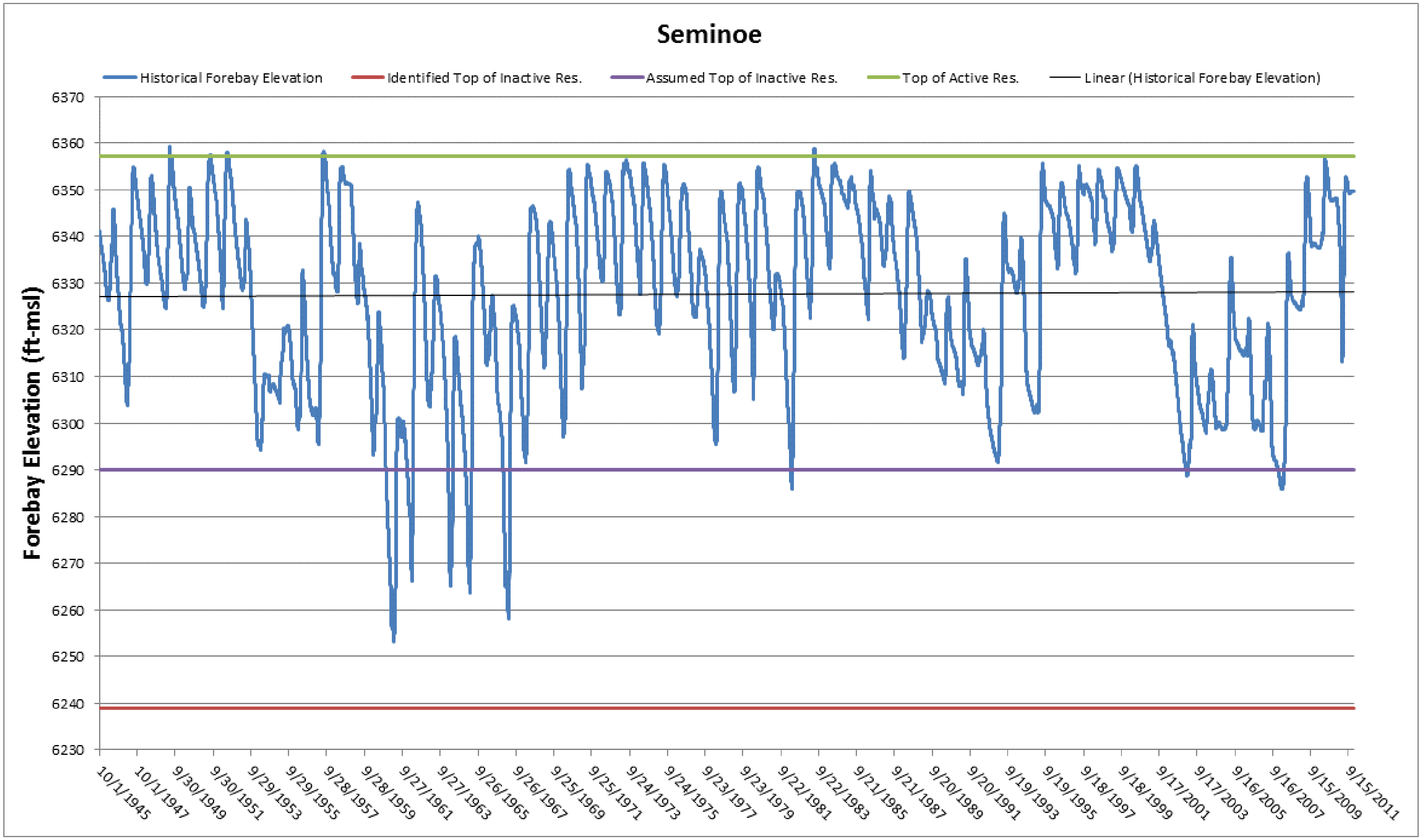


Figure 2-9. Kortes Historic Lake Level Elevations

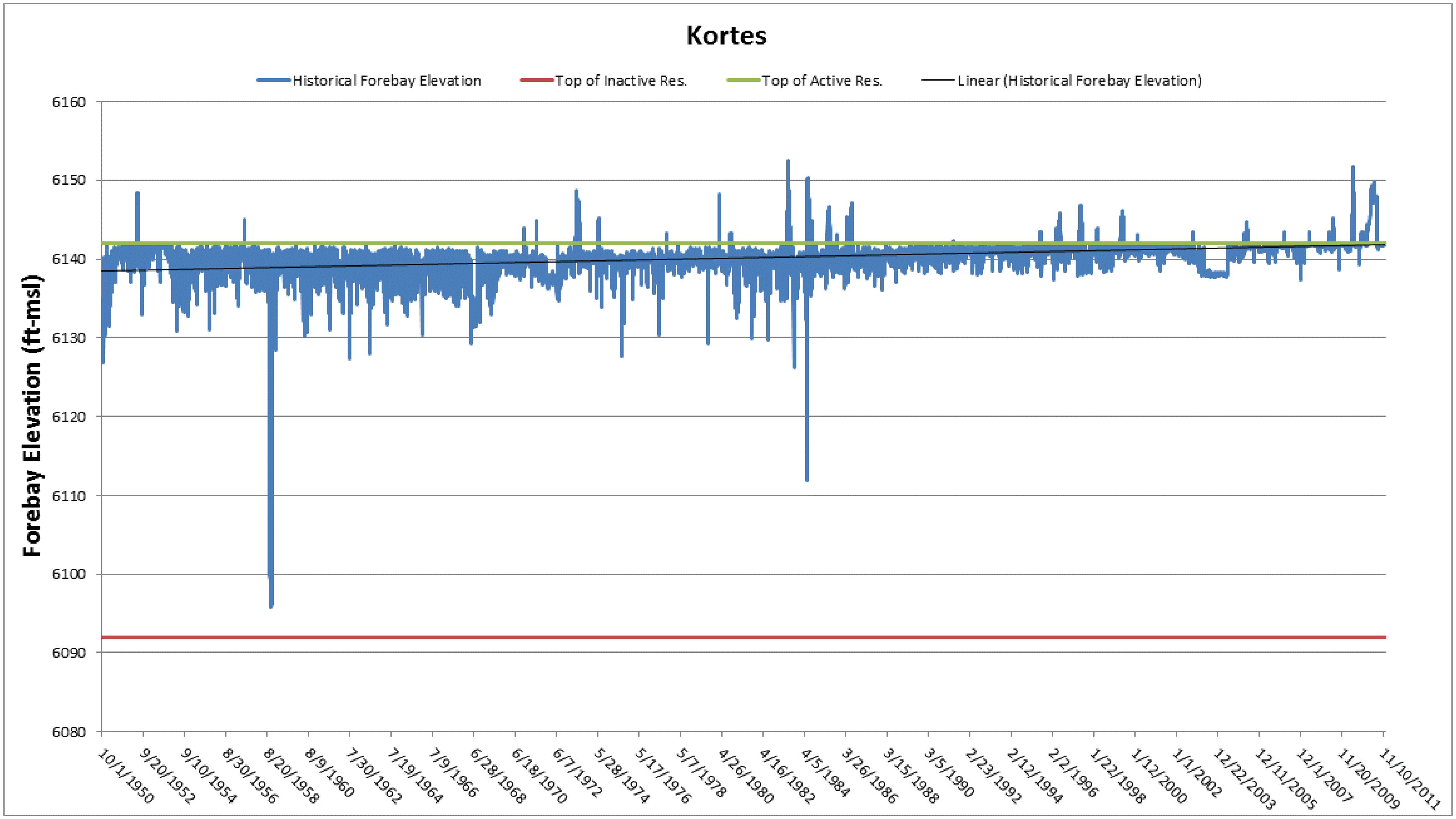


Figure 2-10. Trinity Historic Lake Level Elevations

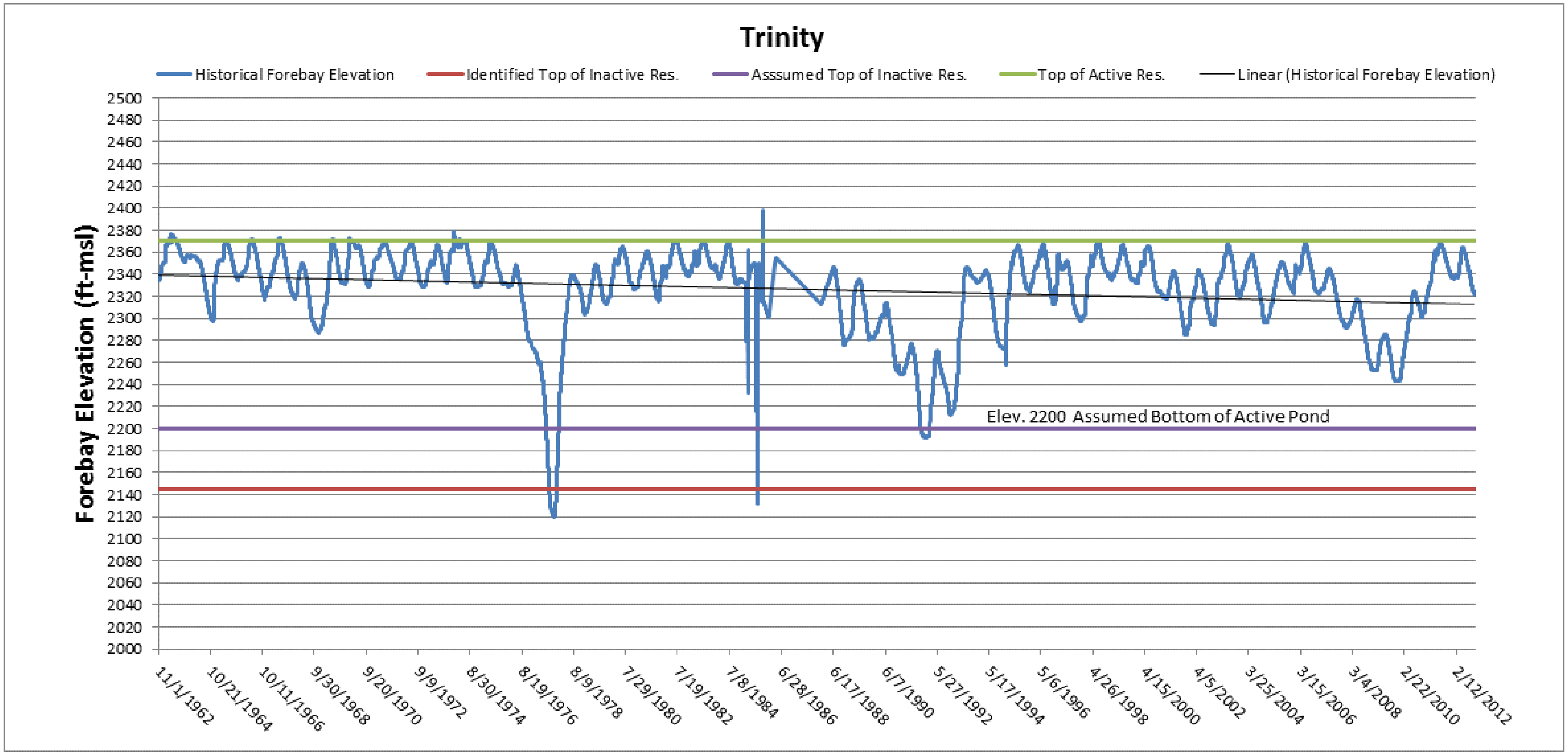
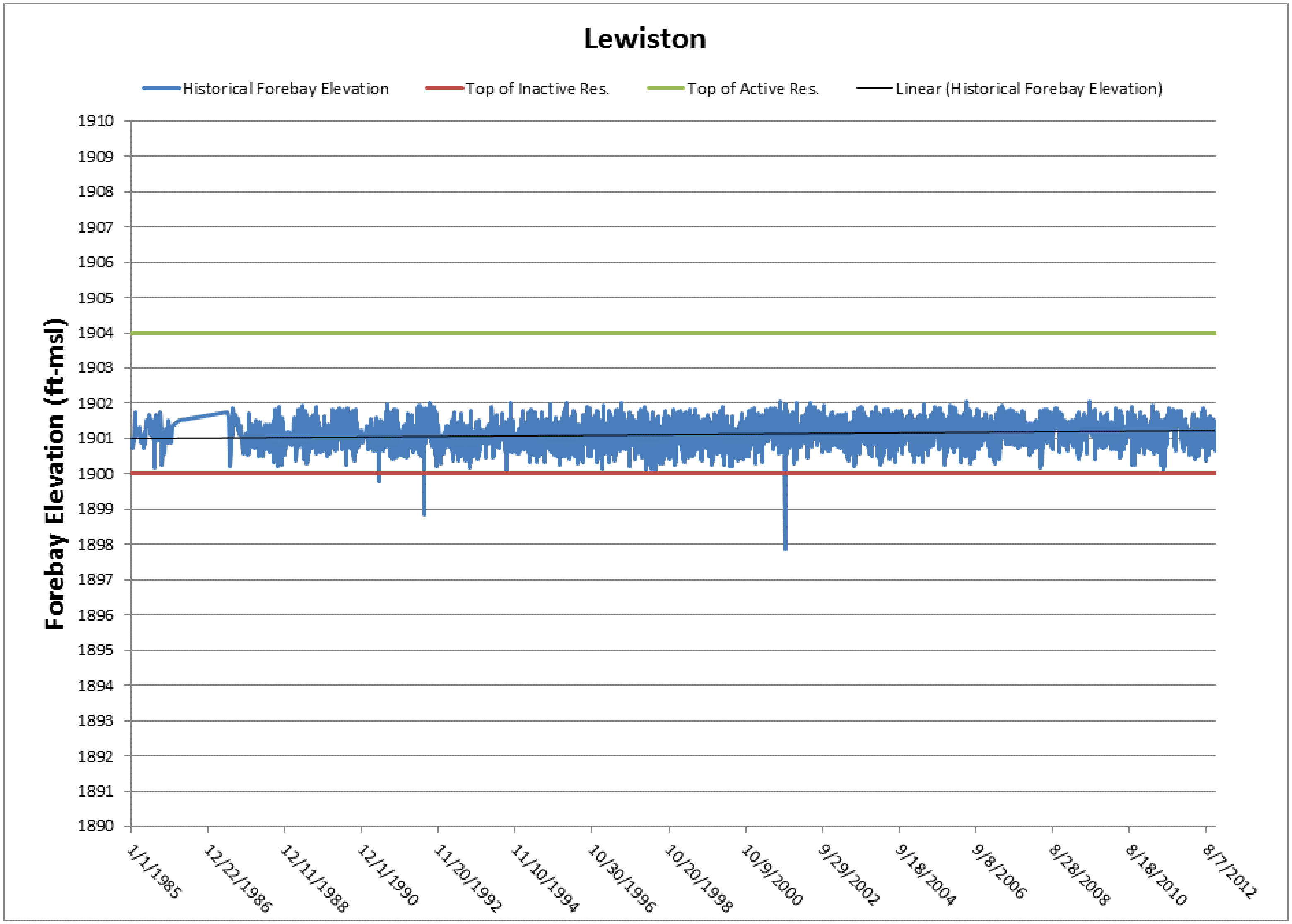


Figure 2-11. Lewiston Historic Lake Level Elevations



2.3 Initial Concept Option Identification

Based on the physical and project-related data that was collected, the project team performed topographic and reconnaissance screening studies to evaluate pump-generation potential associated with Concepts 3 through 5 at each of the four existing complexes. Using topographic and satellite maps, the project team began identifying potential concept options based on the following key site criteria:

- Upper reservoir sites evaluated on the operating head (H) and water conductor length (L);
- An existing lower body of water to serve as the lower pool;
- Avoiding, where possible, urban and populated areas;
- Topographic features suitable for dam construction and reservoir impoundment; and
- Areas offering reasonable access.

The results of this initial concept option identification yielded 46 total options. For each site, the options were numbered relative to each of the Concepts 3, 4 and 5. For Concepts 3 and 4, the project team developed one option for each of the four sites (3YA, 4YA, 3PA, 4PA, 3SA, 4SA, 3TY, and 4TY). The project team then identified multiple Concept 5 options for the four sites and lettered them 5A, 5B, etc. The Concept 5 options include new upper reservoirs that connect to each of the eight existing reservoirs. Some of Concept 5 options have a slight variation in the proposed reservoir size or operation, but are generally in the same location (i.e., 5A1 and 5A2). Figures 2-12 through 2-15 are site maps that show the general location of the options relative to the existing reservoir sites. Figures 2-16 through 2-30 show a more detailed, topographic view of both new reservoirs and new water conductors for each option.

The project team completed preliminary sizing on these 46 options to help determine if they would be technically feasible. Options were initially sized for various run times based on preliminary information such as usable reservoir volume and head differential, estimated based on the top of the active reservoir, top of inactive reservoir and historical lake elevations, as depicted in Figures 2-1 through 2-11. Section 2.4 (following Figures 2-16 through 2-30) presents the design characteristics evaluated for each option.

Figure 2-12. Yellowtail-Yellowtail Afterbay Site Option Locations

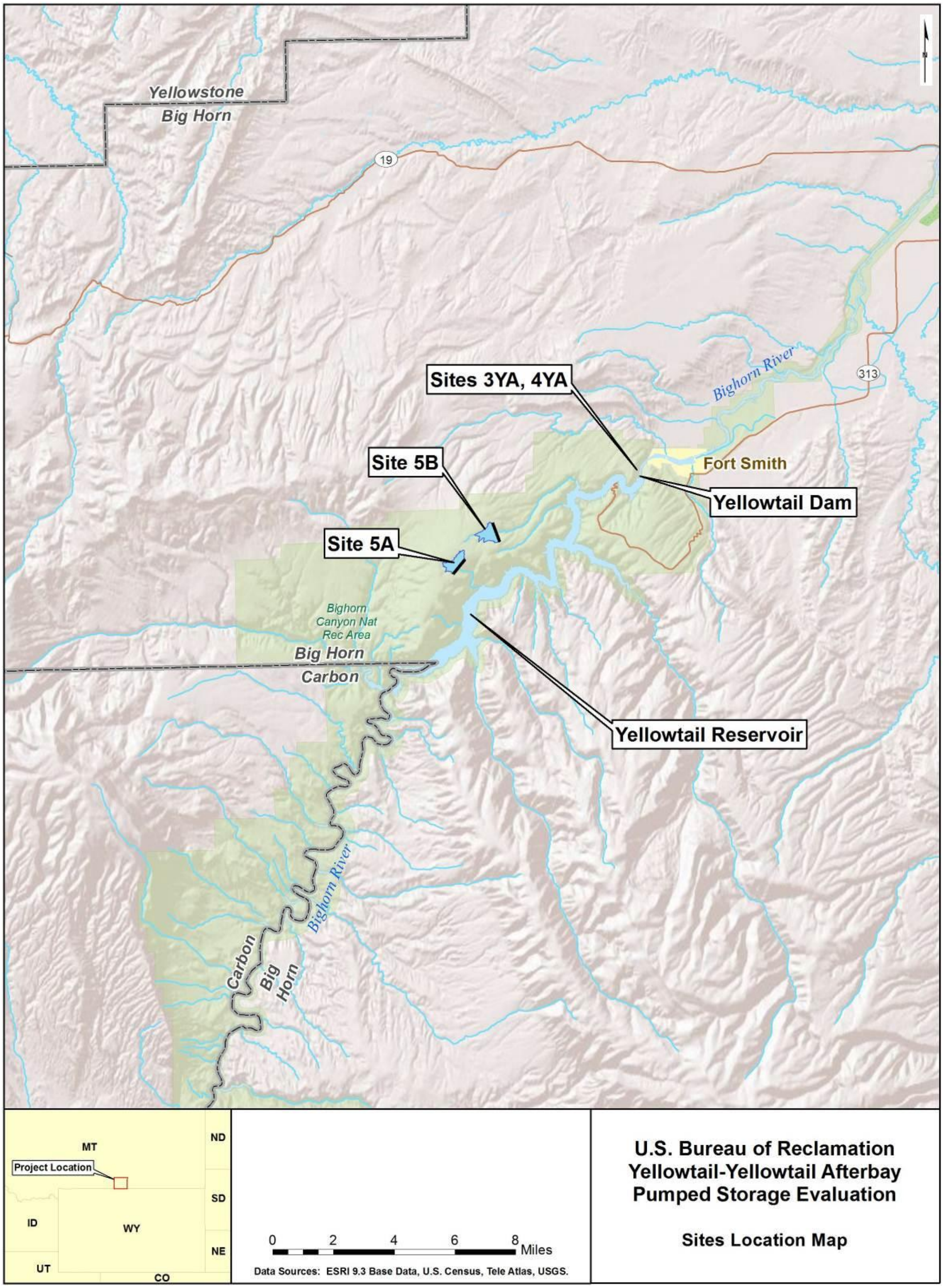


Figure 2-13. Pathfinder-Alcova Site Option Locations

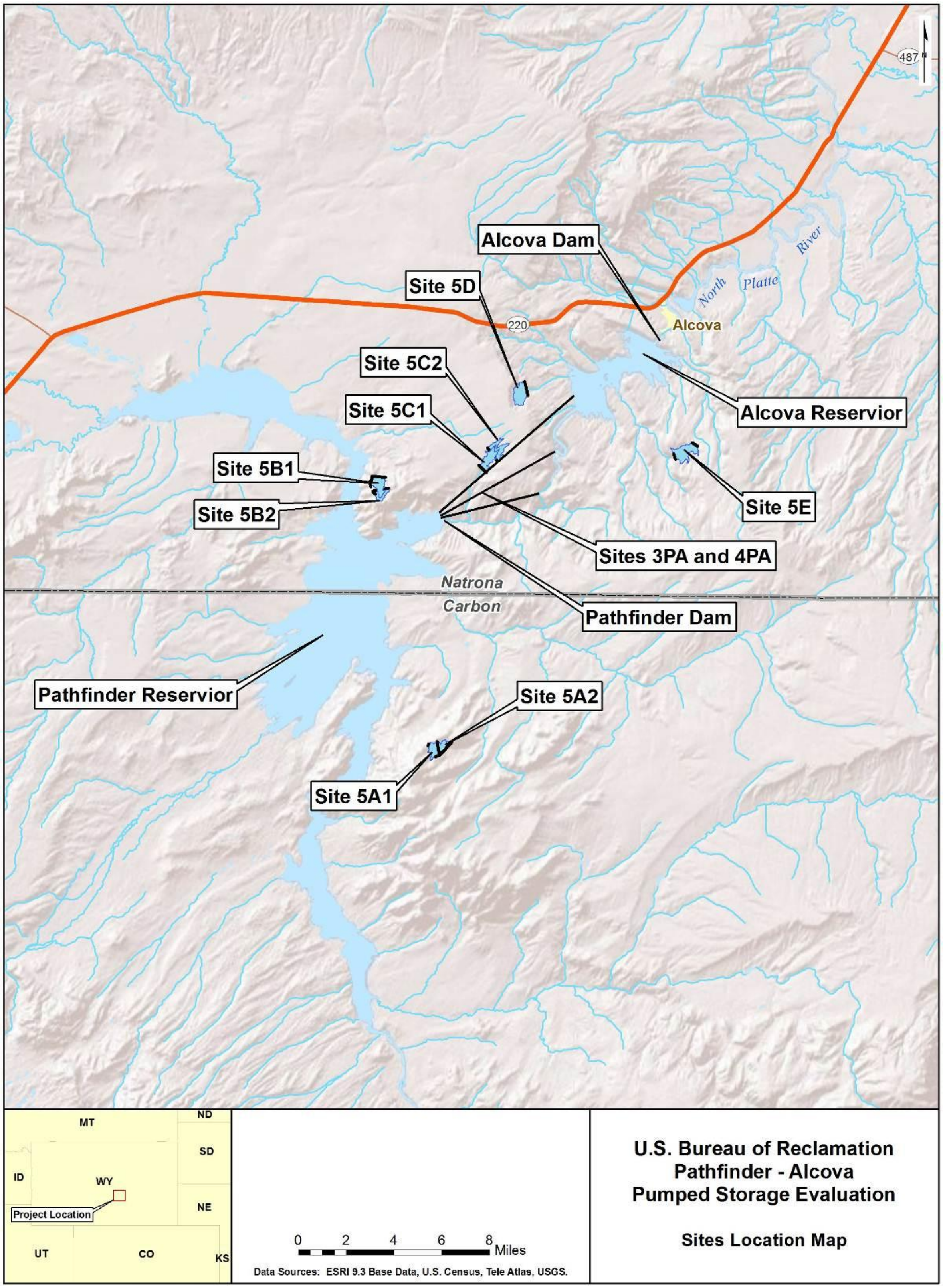


Figure 2-14. Seminoe-Kortes Site Option Locations

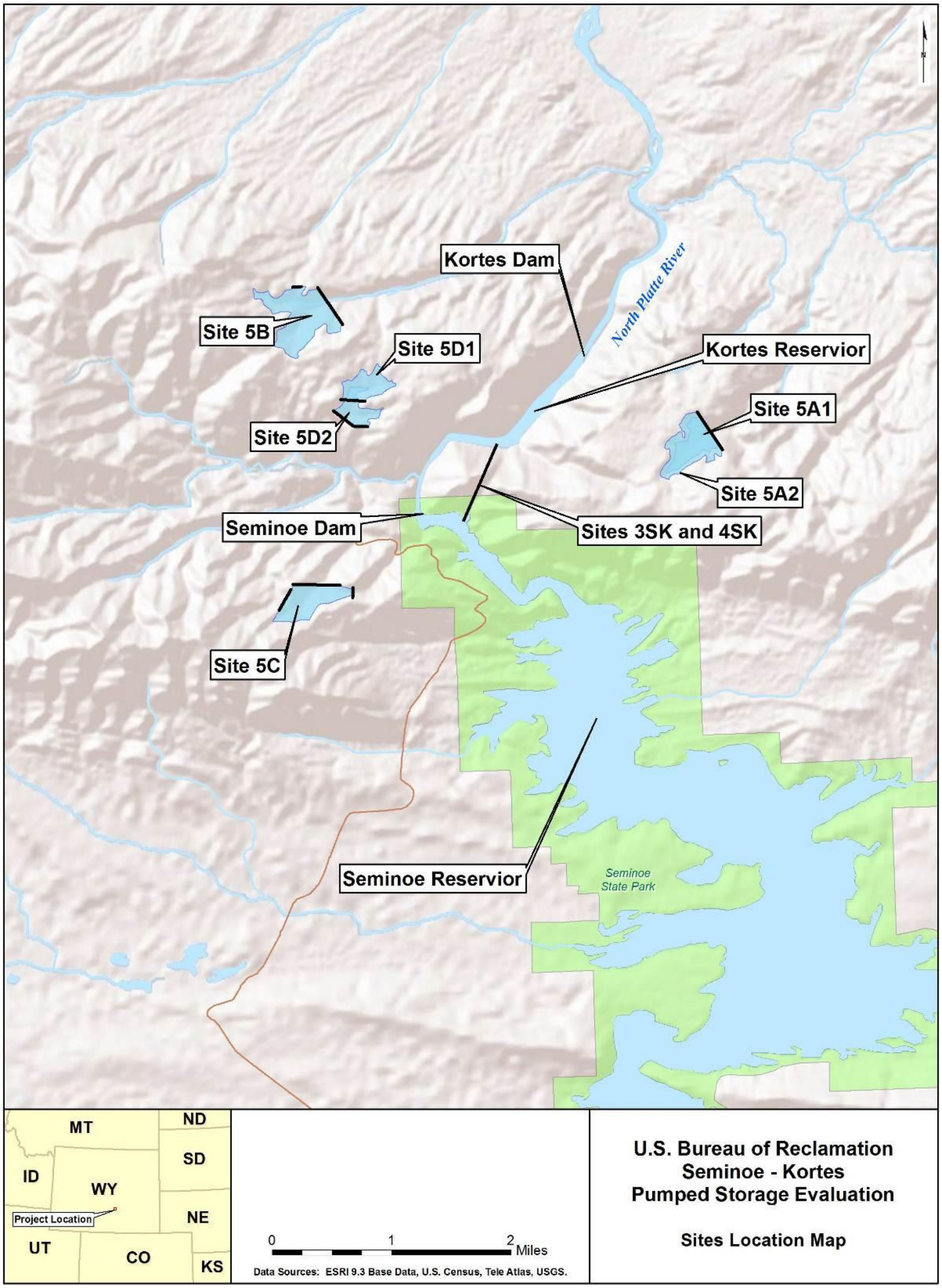


Figure 2-15. Trinity-Lewiston Site Option Locations

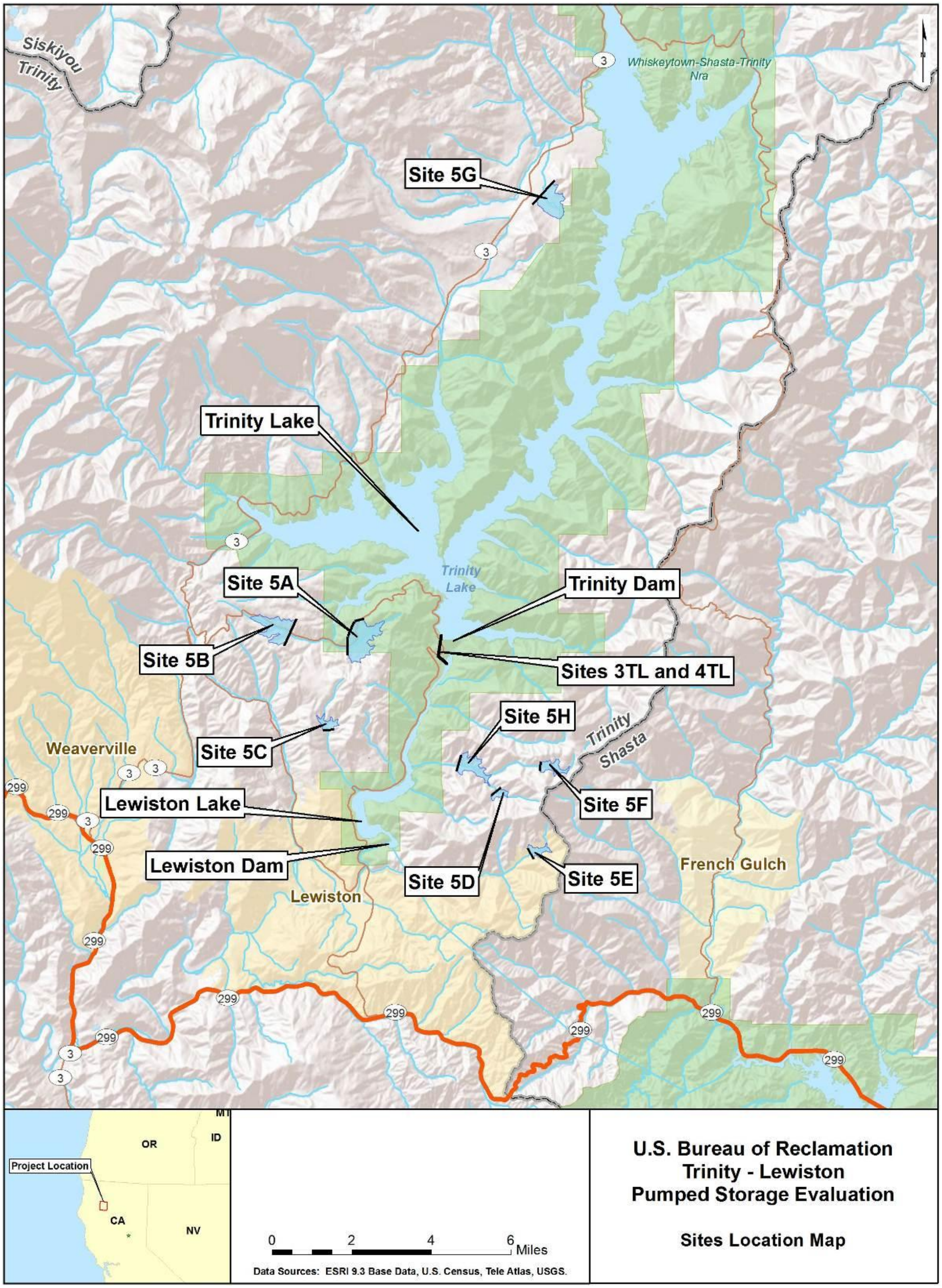


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Figure 2-16. Yellowtail Options 5A and 5B Facilities Layout

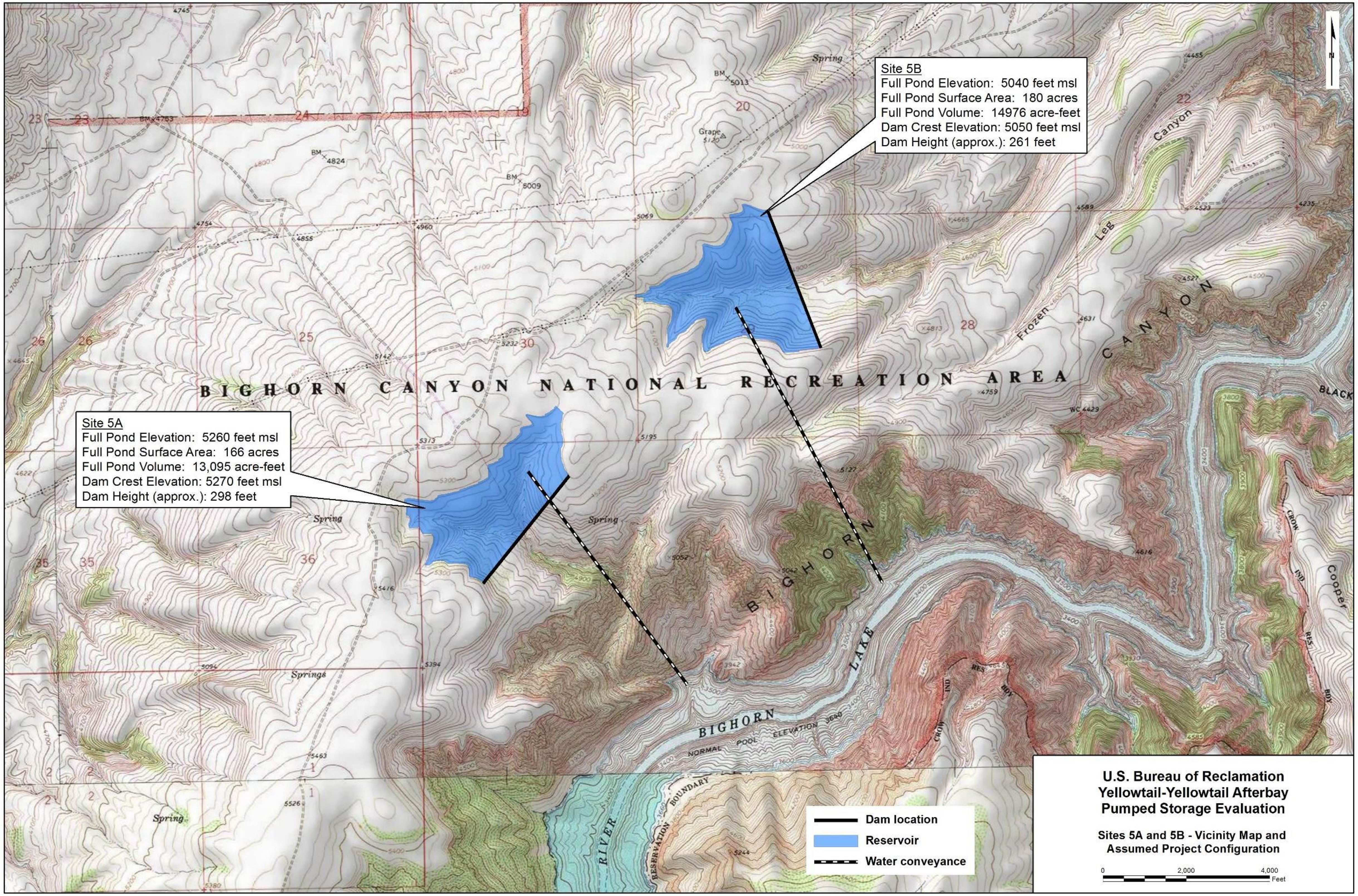


Figure 2-17. Yellowtail Options 3YA and 4YA Existing Reservoir Concept

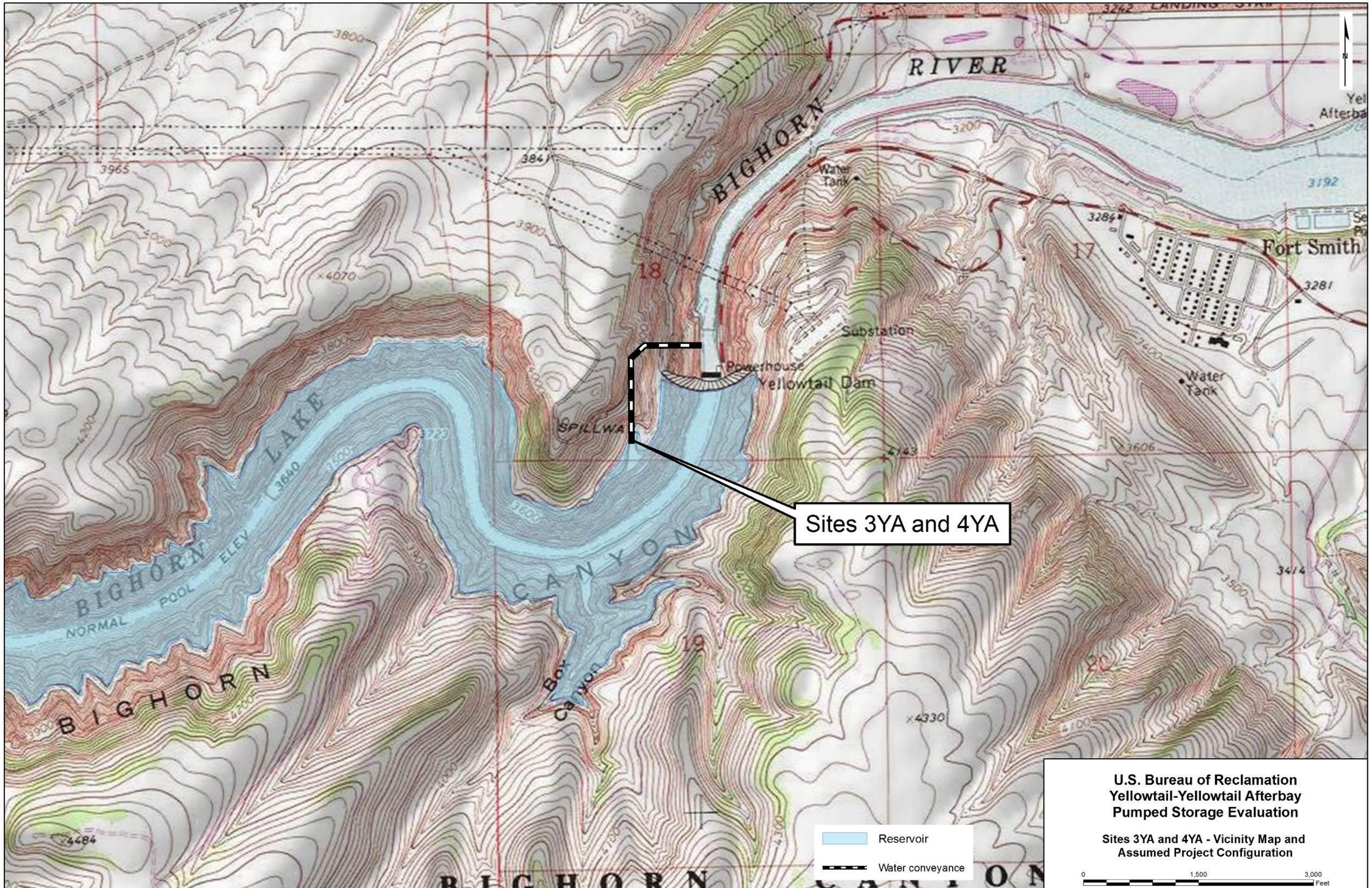


Figure 2-18. Pathfinder-Alcova Existing Reservoir Concept

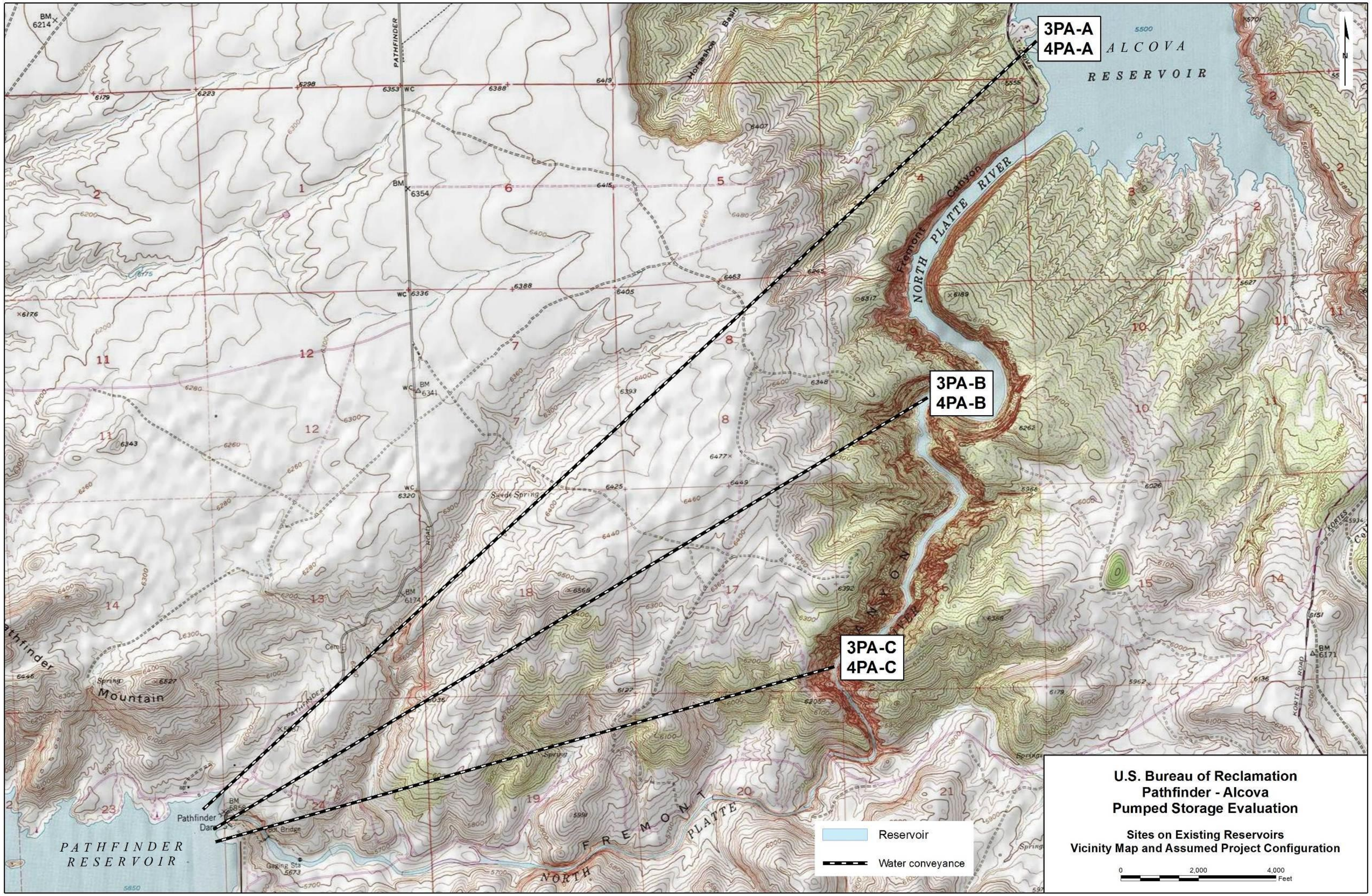


Figure 2-19. Pathfinder-Alcova Options 5A1 and 5A2 Facilities Layout

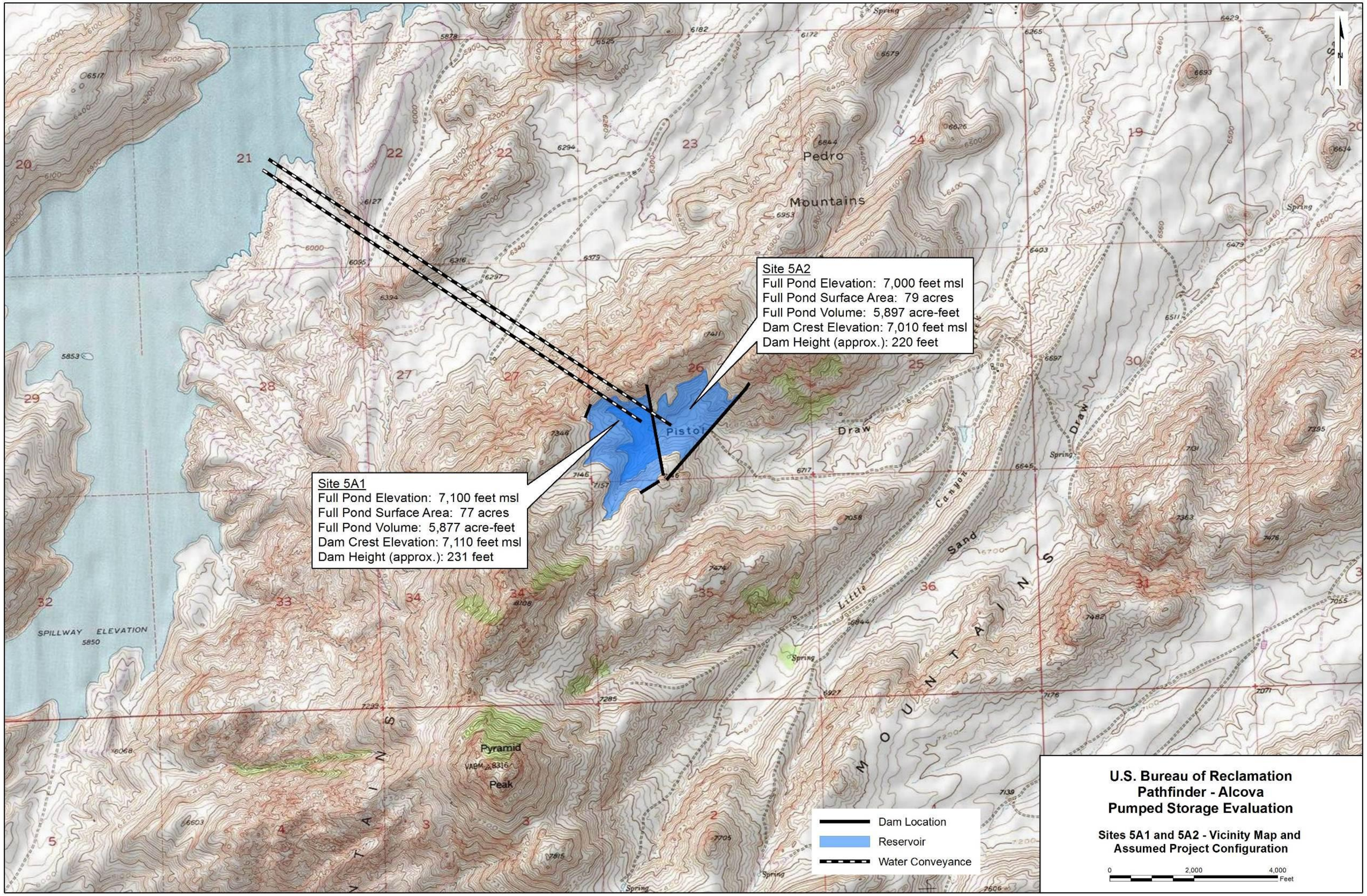


Figure 2-20. Pathfinder-Alcova Options 5B1 and 5B2 Facilities Layout

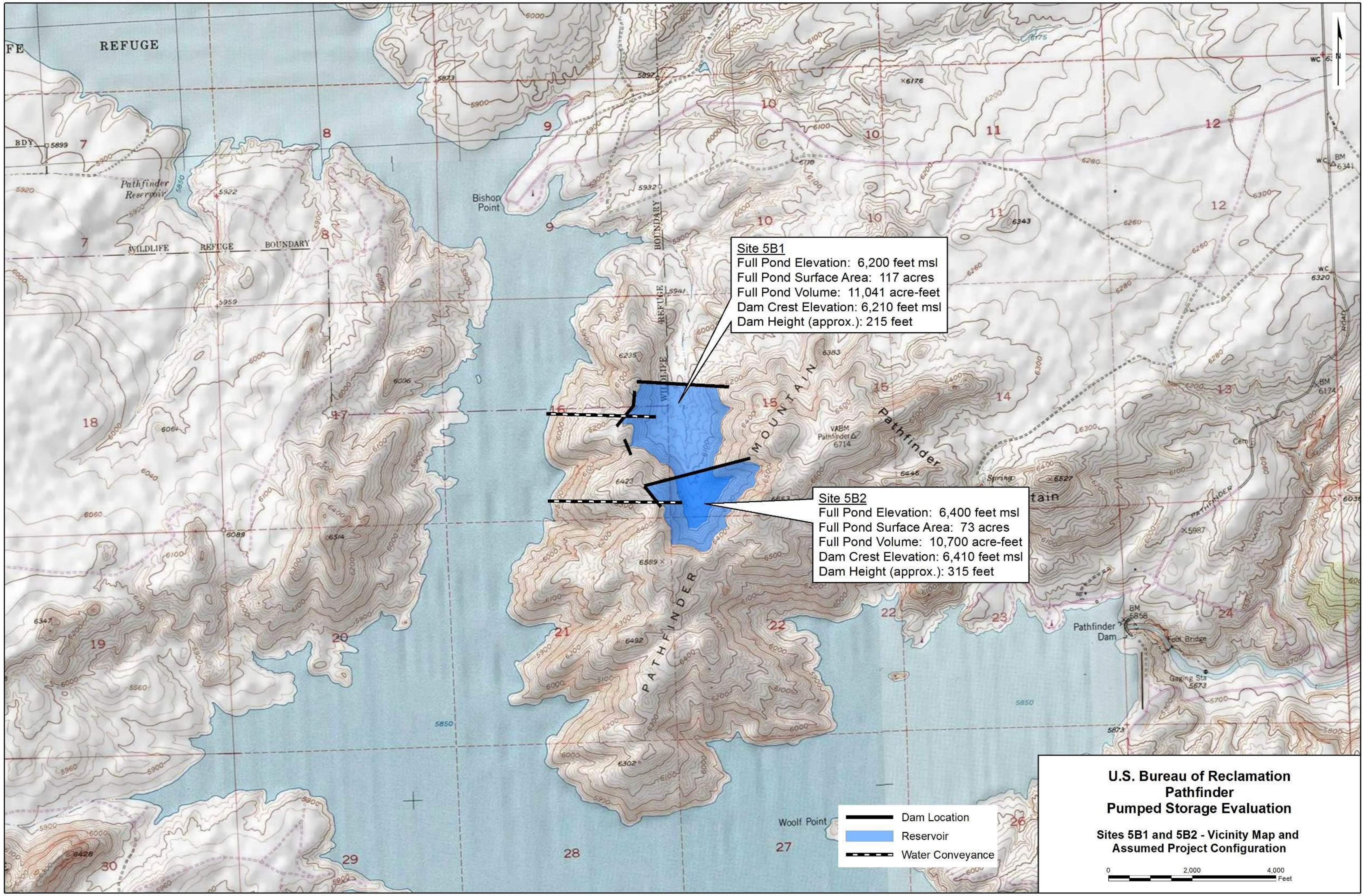


Figure 2-21. Pathfinder-Alcova Options 5C1-A, 5C1-B, 5C1-C, and 5C1-D Facilities Layout

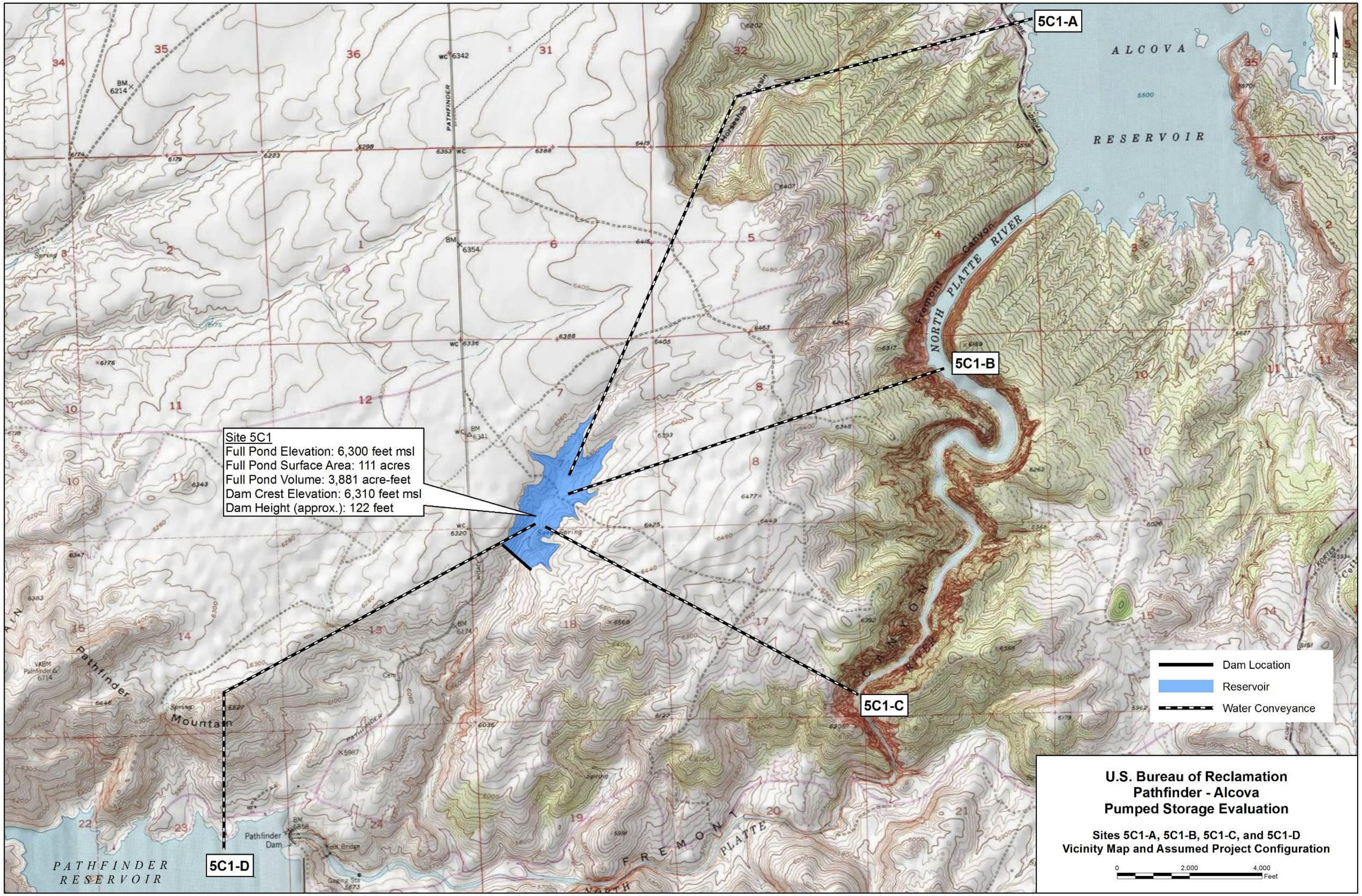


Figure 2-22. Pathfinder-Alcova Options 5C2 and 5D Facilities Layout

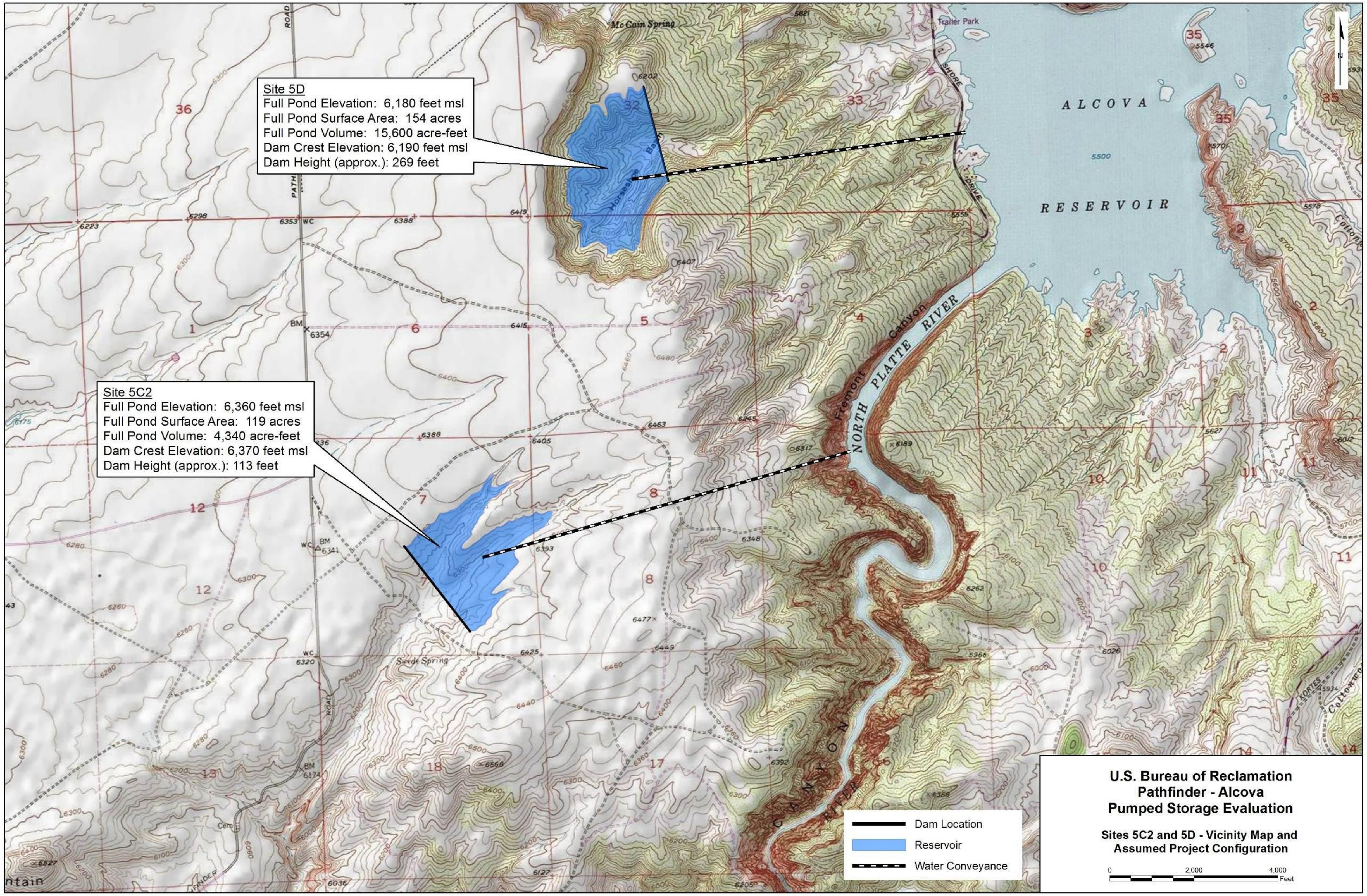


Figure 2-23. Pathfinder-Alcova Option 5E Facilities Layout

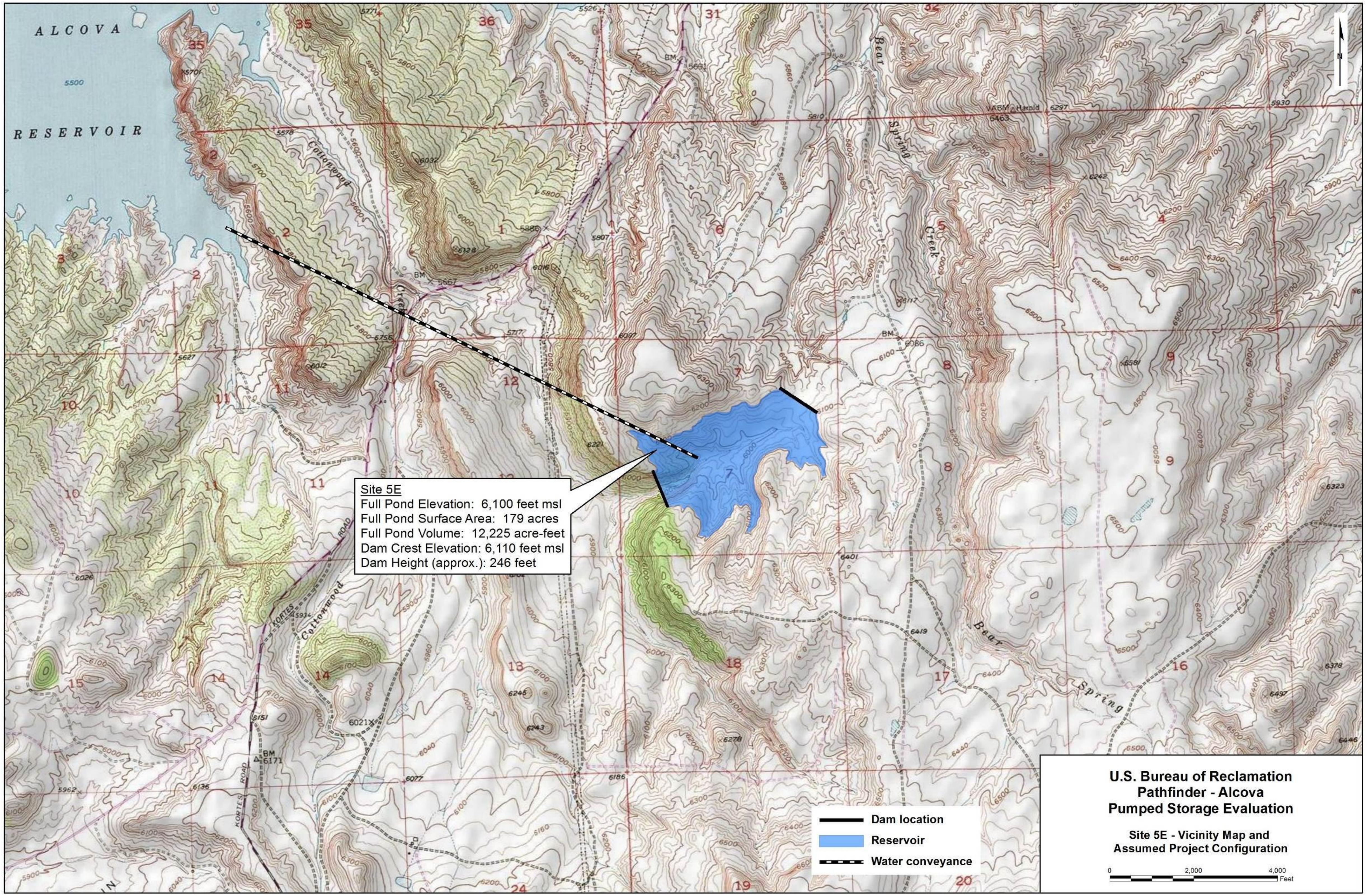


Figure 2-24. Seminoe-Kortes Existing Reservoir Concept

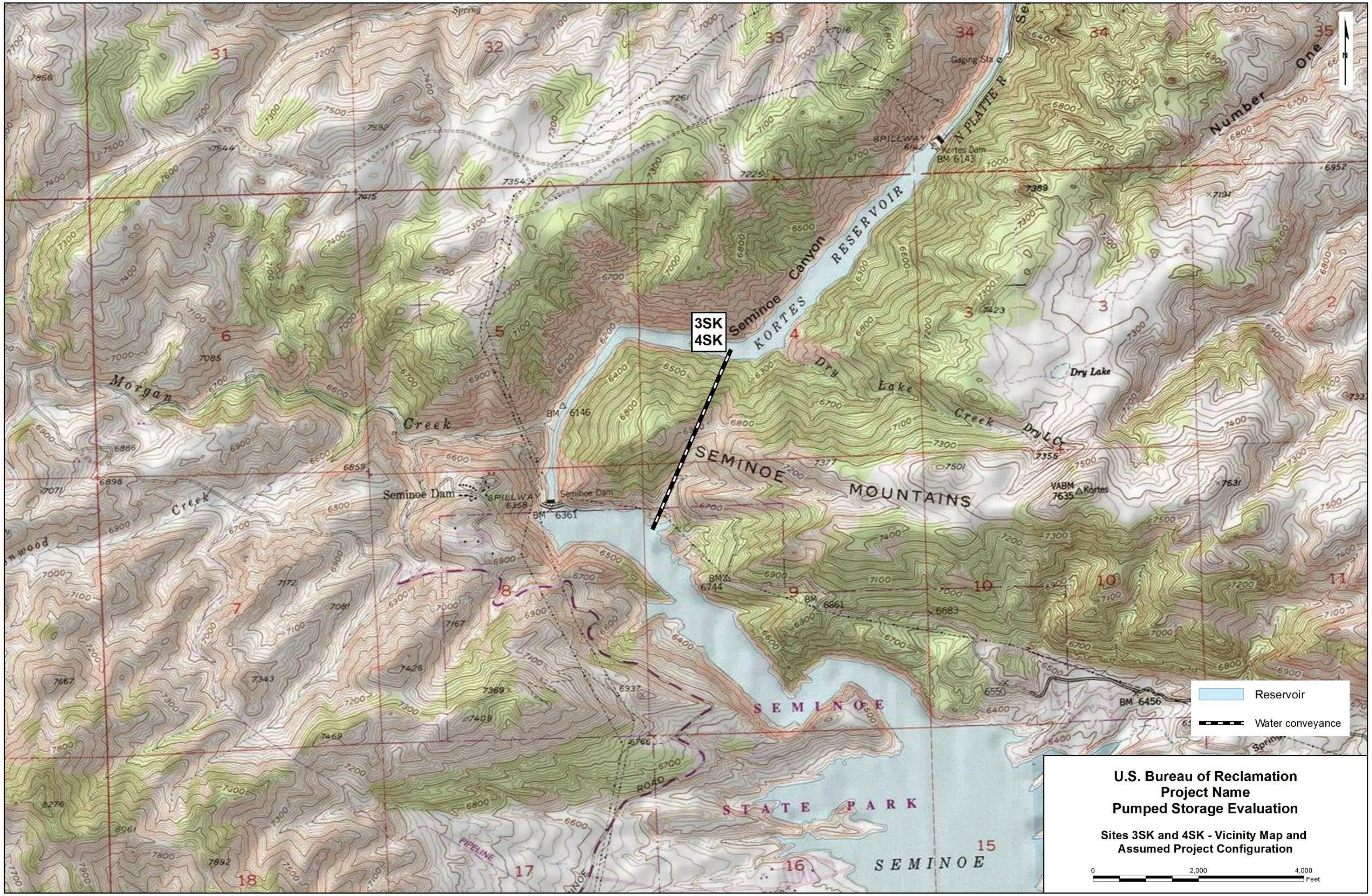


Figure 2-25. Seminoe-Kortes Options 5A1, 5A2, 5B, 5C, 5D1, and 5D2 Facilities Layout

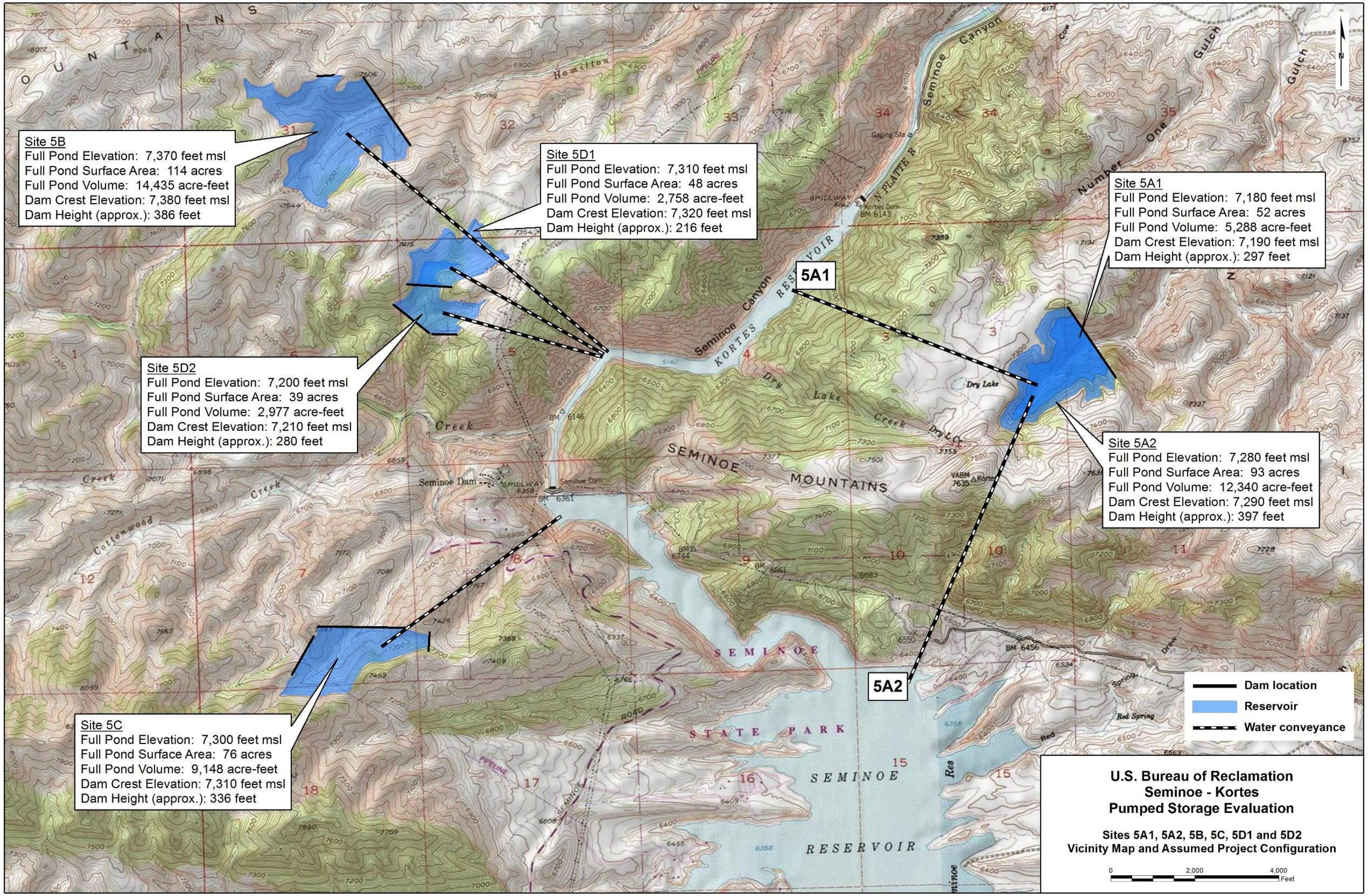


Figure 2-26. Trinity-Lewiston Existing Reservoir Concept

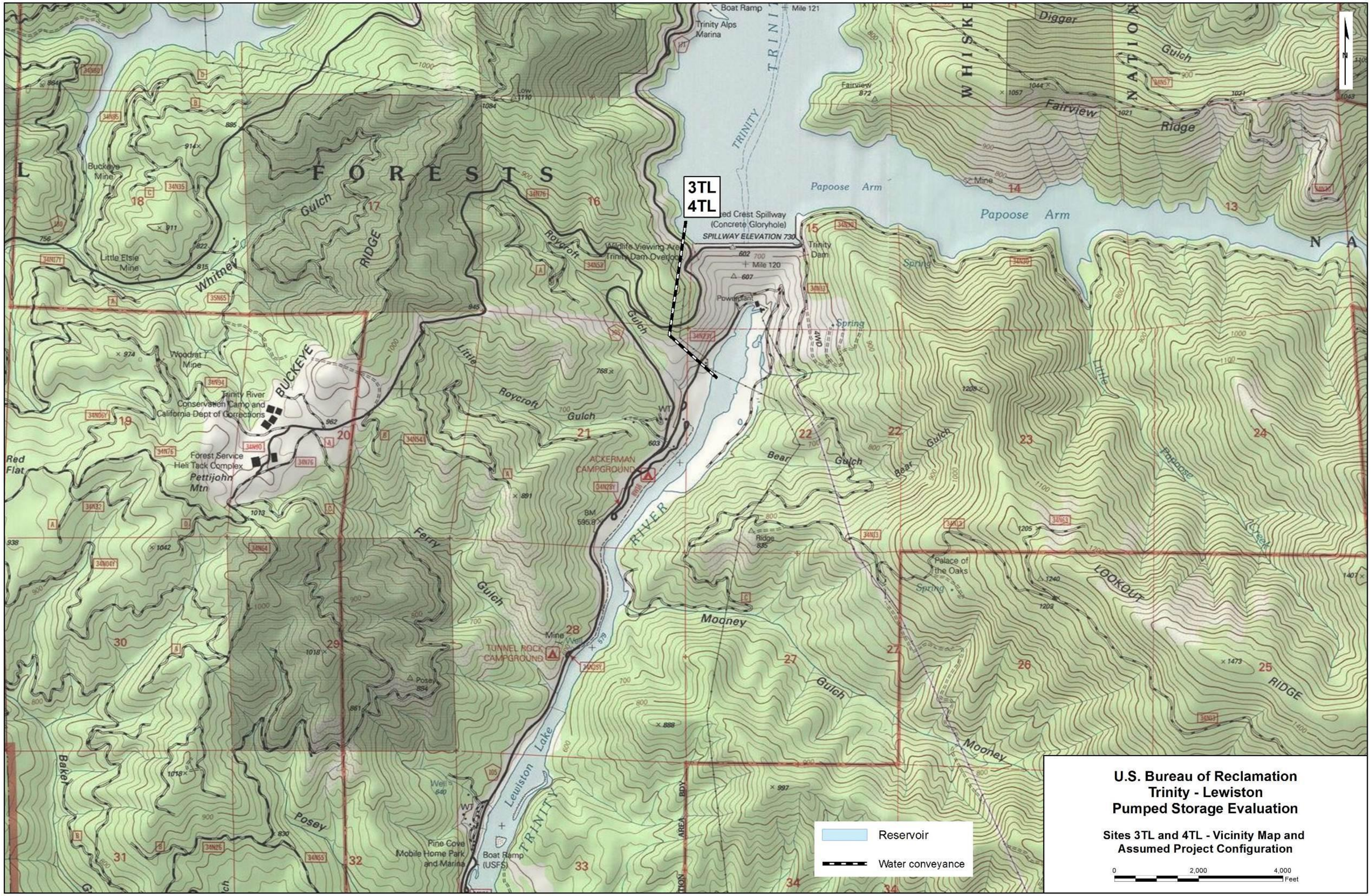


Figure 2-27. Trinity-Lewiston Options 5A and 5B Facilities Layout

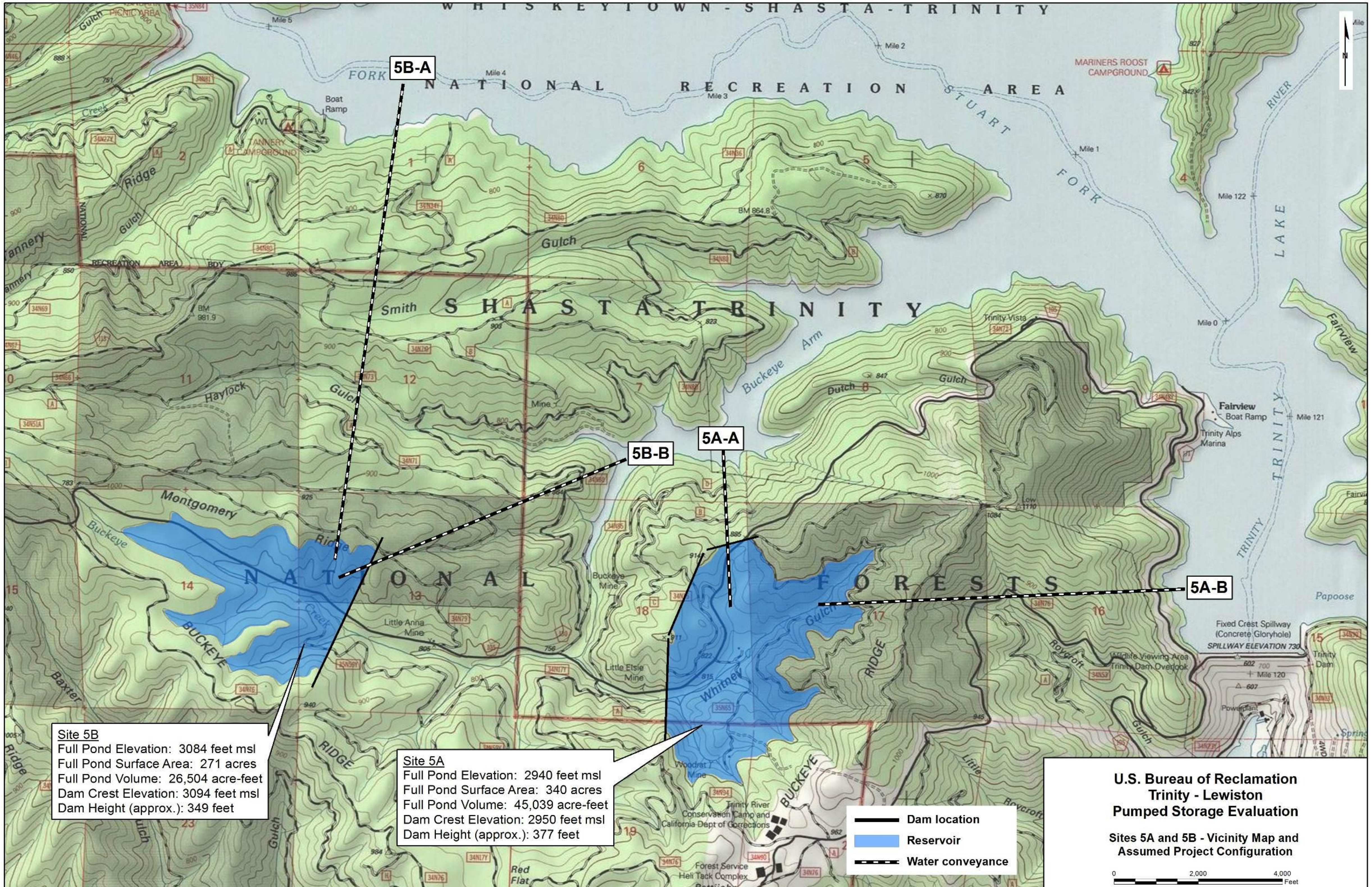


Figure 2-28. Trinity-Lewiston Option 5C Facilities Layout

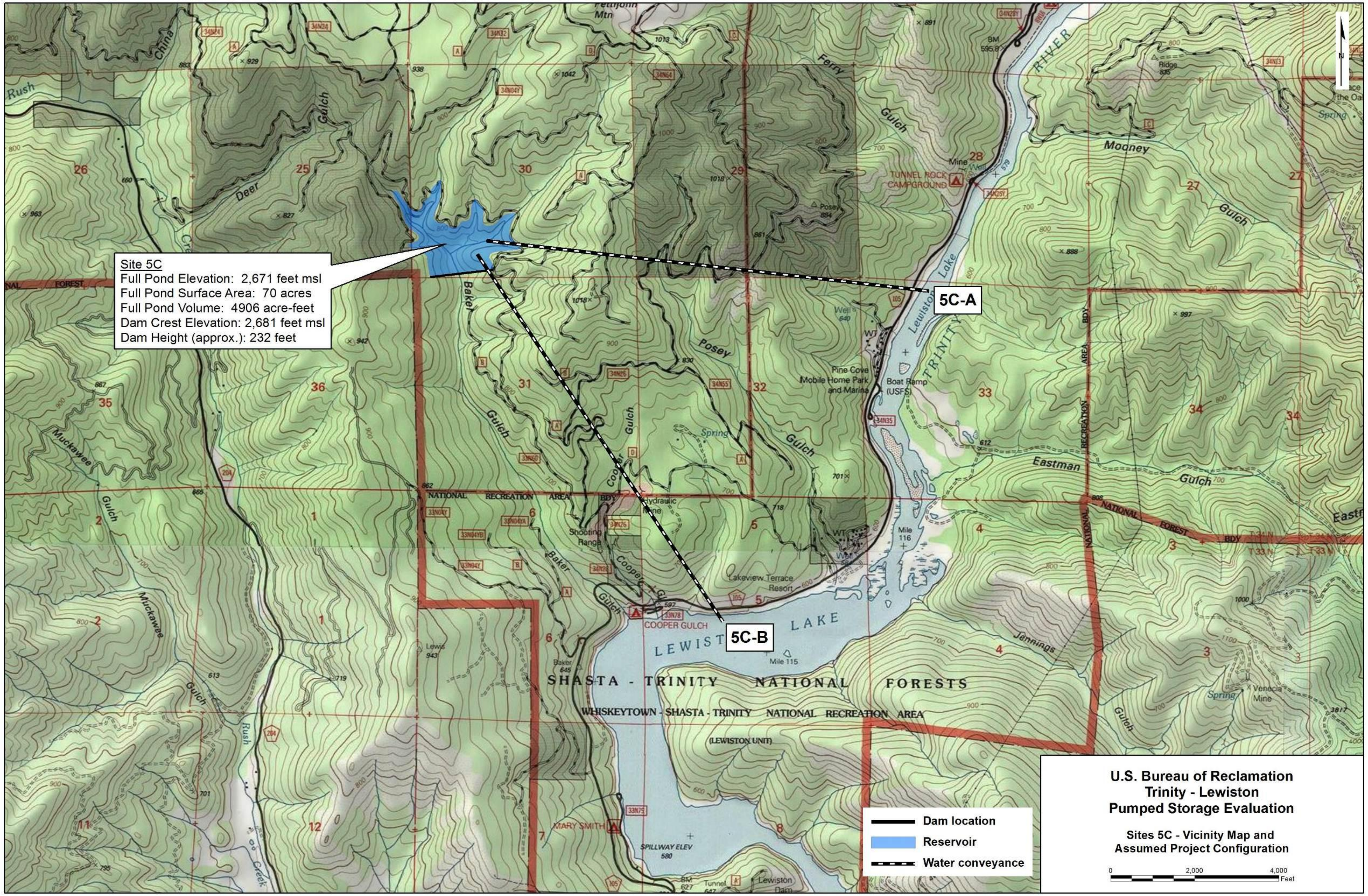


Figure 2-29. Trinity-Lewiston Options 5D, 5E, 5F, and 5H Facilities Layout

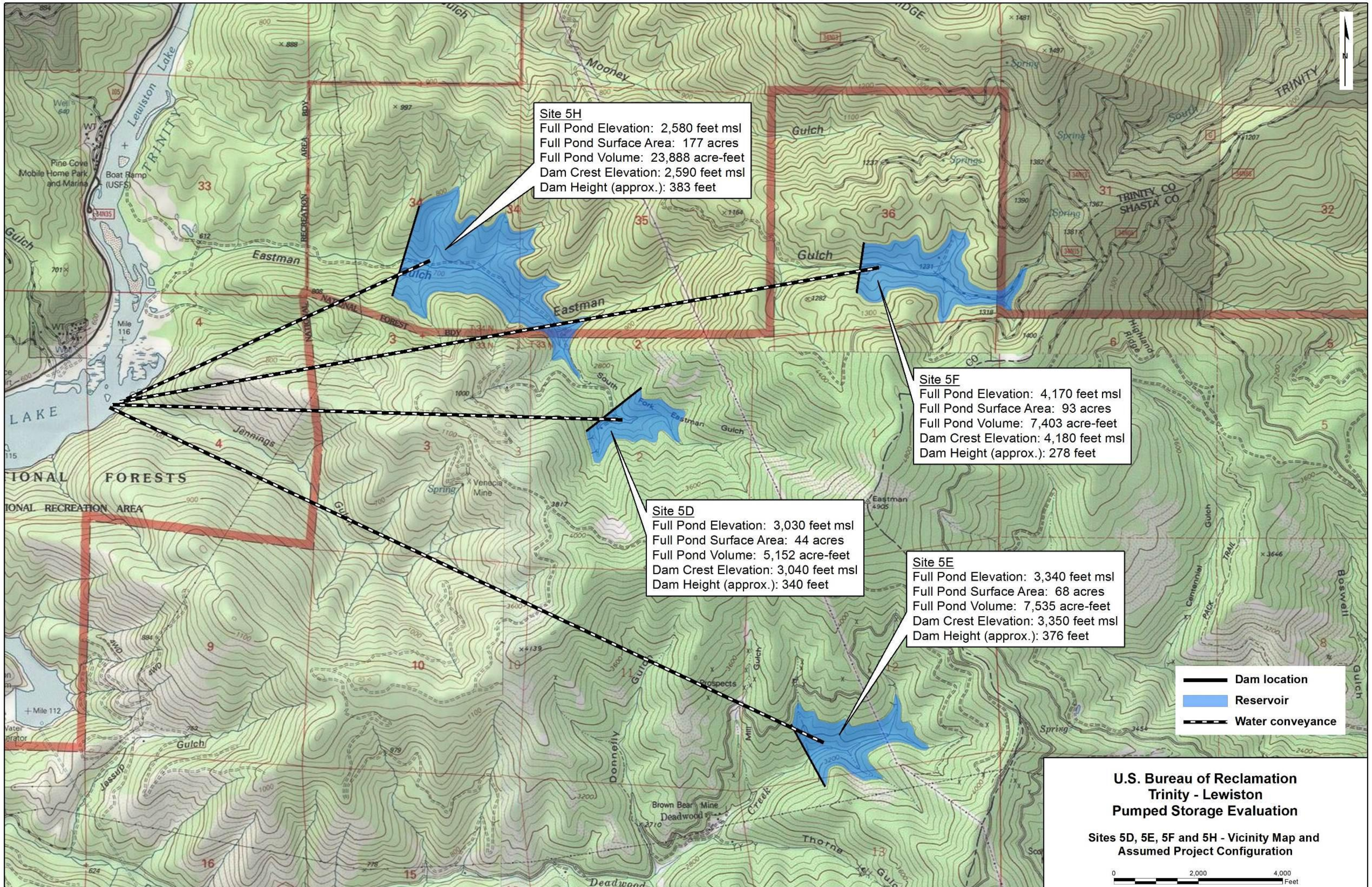
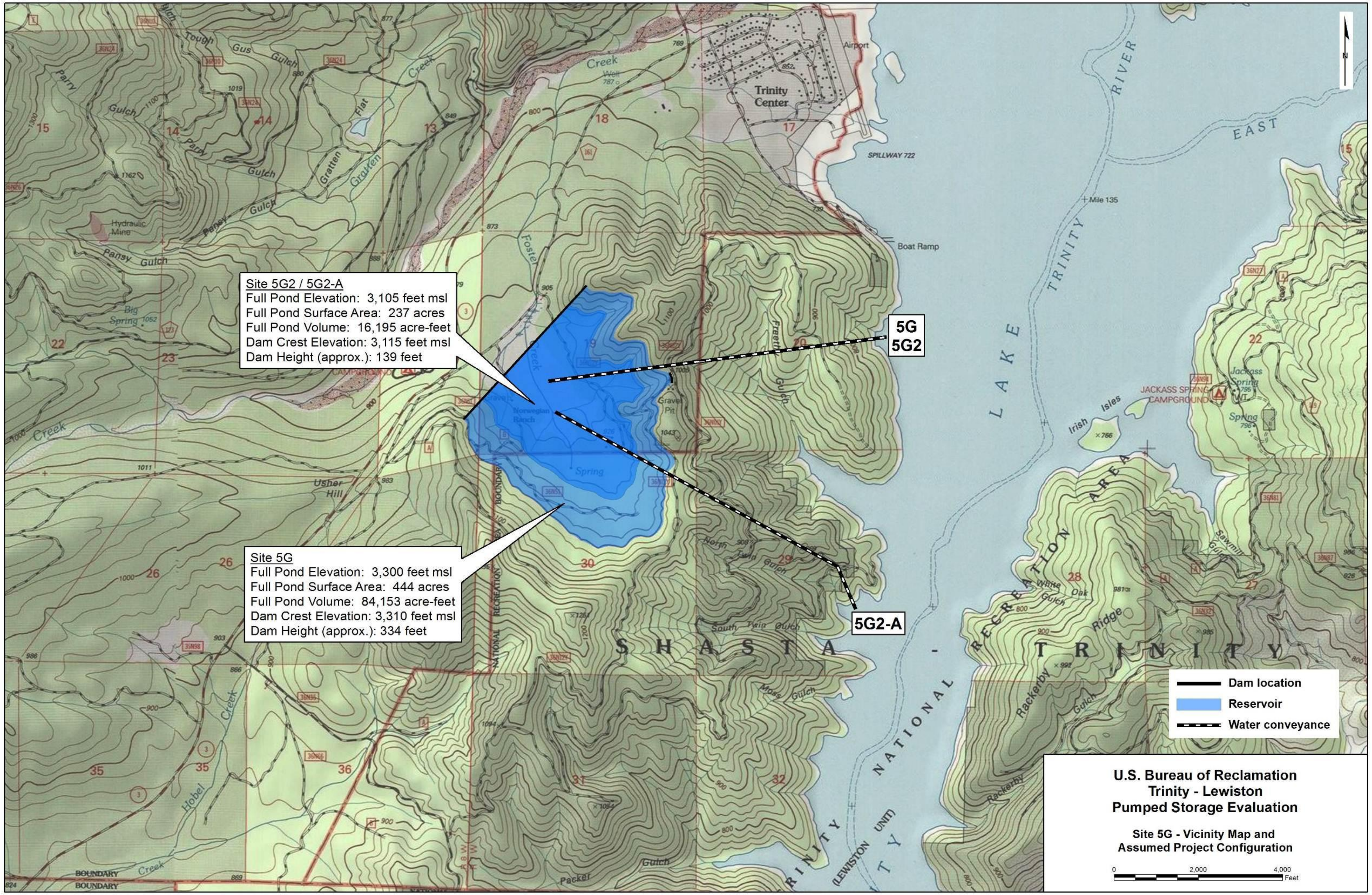


Figure 2-30. Trinity-Lewiston Option 5G Facilities Layout



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2.4 Preliminary Sizing

To assist with screening each of the potential options, the project team considered various 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
- Water conveyance concepts

These characteristics were examined using the methods listed below.

2.4.1 Dam Volume Estimates

All dams were assumed to be rockfill concrete-faced and constructed with a crest width of 30 feet on slopes of 1.75H:1V with 10 feet of freeboard and 20 feet of foundation preparation. The maximum allowable dam height was 400 feet.

2.4.2 Upper Reservoir Area-Volume

Upper reservoir area-volumes and drawdown were estimated from GIS-based digital topography.

2.4.3 Upper Reservoir Active Storage

Active storage was determined via the following sources:

- Concept 3 and 4 options utilized reservoir operational data for the existing reservoir provided in Figures 2-1 through 2-11.
- Concept 5 utilized topography information obtained from GIS-based digital topography.

Where necessary, the active volumes, heads and reservoir operational limits were governed by the operational restrictions of pump-turbine design criteria to limit the minimum to maximum gross head ratio to 80 and 70 percent for single speed and variable speed technology, respectively.

2.4.4 Upper Reservoir Energy Storage

Energy storage within the upper reservoir was estimated using the following relationship:

$E = 0.88\ HS \times 10^{-3}$

Where: E = Energy Storage (Megawatt hours [MWh])
H = Average Gross Head (ft)
S = Active Storage (acre-feet)

2.4.5 Capacity

Approximate generating capacity (MW) was estimated using the following relationship for hours of storage ranging from 10 to 40 hours:

C = E/Hours of Storage

Where: C = Rated Generating Capacity (MW)
E = Energy Storage (MWh)

2.4.6 Generating Discharge

The maximum generating discharge was estimated using the following equation:

$Q = 11{,}800\ C/He = 13{,}720\ C/H$

Where: Q = Design Discharge (cubic feet per second [cfs])
H = Average Gross Head (ft)
C = Rated Generating Capacity (MW)
e = Overall Generating Efficiency (assumed 0.86)

2.4.7 Power Complex Configuration

An underground power complex configuration was assumed for Concept 5 options with the water conductors consisting of a headrace tunnel (vertical and horizontal), manifold tunnel, penstock tunnels, draft tube tunnels, and tailrace tunnels.

A surface power complex configuration was assumed for Concept 3 and 4 options with the water conductors consisting of a headrace tunnel, manifold tunnel, penstock tunnels and depending on the site, draft tube tunnels.

2.4.8 Water Conductor Sizing

The number and size of water conductors was based on the maximum permissible velocity, the assumed number of generating units, assumed maximum tunnel diameter, and general constructability. Conductor sizes were estimated using the following formula:

$$D > (1.273\ Q/V)^{0.5}$$

Where D = Water Conductor Diameter (ft)
Q = Design Discharge (cfs)
V = Assumed Maximum Flow Velocity (ft/second)

Description	**Assumed Maximum Flow Velocity (ft/second)**
Headrace Tunnel	20
Penstock Tunnel	17-32
Draft Tube Tunnel	6-17
Tailrace	15

2.5 Technical Screening

As part of the initial screening process, the project team compiled the following preliminary site characteristics for each option. Options that appeared to offer the most development potential were then selected to move forward with conceptual layouts and Class 5 cost opinions. The following technical criteria were used for screening:

- Maximum L/H Ratio (Electric Power Research Institute [EPRI] Document No. GS-6669 [1990]) – For the purpose of site identification and initial screening, EPRI offers the following criteria utilizing the following relationship between operating head (H) and water conductor length (L). These criteria are guidelines and do not mean that if the L/H ratio is slightly more, the pump-generation project is infeasible. If the L/H ratio was close and other technical features of the option looked favorable, the option was not screened out.

Operating Head (ft)	Maximum L/H Ratio
200 - 300	<5
300 - 500	<7
500 - 750	<10
750 and greater	<12

- Typical Operating Range of Pump-Turbine Units (Minimum head/Maximum head) – For the purposes of this study, the following range of acceptable unit operating head ranges were utilized:

  – Single-Speed Technology – 80% to 100% of maximum head

  – Variable-Speed Technology – 70% to 100% of maximum head

  It should be noted that single-speed unit technology was utilized for the purpose of developing conceptual layouts and capital cost opinions due to the availability and abundance of historical parametric cost data. The actual selection of a preferred unit technology is generally the product of more in-depth studies with consideration given to operational objectives, costs, and benefits, and therefore beyond the scope of this Phase 1 evaluation.

- Reservoir Depth – The tie in point to the lower reservoir has to have an adequate depth to access the usable volume to the upper reservoir. If the reservoir was too shallow at the tie in point, the option was screened out.
- Energy Storage – Energy storage is the potential power generation of the project, measured in MWh. Energy storage created by the options must be large enough for consideration. Energy storage potential was generally compared across study options and to existing pump-generation projects. Options that offered relatively small potential energy storage were screened out.
- Resulting Installed Capacity – As noted in Section 2.4.5, installed capacities for each option were provided for run times of 10, 20, 30, and 40 hours. For the purposes of screening, a 10-hour run time was assumed. Such a run time would reflect daily cycling and integration of intermittent renewable generation resources. Optimal run times and associated installed capacities will be further investigated in the Phase 2 evaluation. For comparison purposes, Table 2-1 provides a summary of data for pumped storage projects constructed in the United States before 1991. Similar to energy storage, the resulting installed capacity must be large enough for consideration. Options with relatively small installed capacity were screened out.
- Estimated Dam Volume – For Concept 5 options, the estimated dam volume (in cubic yards) needs to be reasonable relative to the general size of the project. In general, a very large dam volume means higher costs, more construction effects, and more environmental effects.

Table 2-1. Summary of Plant Data

Plant Name	Plant Location: Nearest Town, State	Plant Capacity MW	First Commercial Power	Number of Reversible Units	Number of Main Conduits	Surge Tanks	Static Head: Max, Min (ft) Max/Min Ratio	Storage Capacity Generation Hours	Length of Waterways ft	L/H Ratio
Bad Creek	Salem, SC	1,000	1991	4	1	none	1,230, 1,040 Ratio: 1.18	24	9,519	8.3
Balsam Meadow (Now Eastwood)	Shaver Lake, CA	200	1987	1	1	downstream	1,352, 1,316 Ratio: 1.03	8	12,488	10.0
Bath County	Warm Springs, VA	2,100	1985	6	3	upstream	1,260, 1,080 Ratio: 1.17	11	9,117	7.7
Bear Swamp (Now Cockwell)	Rowe, MA	600	1974	2	2	none	770, 680 Ratio: 1.13	6	1,834	2.4
Blenheim-Gilboa	Blenheim and Gilboa, NY	1,000	1973	4	4	none	1,143, 1,097 Ratio: 1.04	12	3,895	3.5
Cabin Creek	Georgetown, CO	300	1967	2	2	none	1,226, 1,095 Ratio: 1.12	5	4,300	3.7
Carters	Chatsworth, GA	258	1976	2	2	none	406, 315 Ratio: 1.29	7	838	2.4
Castaic	Castaic, CA	1,250	1973	6	1	upstream	1,098, 800 Ratio: 1.37	10	41,275	38.6
Clarence Cannon	Center, MO	31	1984	1	1	none	117, 59 Ratio: 1.98	9	70	0.9
De Gray	Arkadelphia, AK	28	1971	1	1	none	206, 146 Ratio: 1.41	7	1,570	9.2
Edward Hyatt	Oroville, CA	293	1967	3	2	none	675, 500 Ratio: 1.35		581	0.9
Fairfield	Jenkinsville, SC	512	1978	8	4	none	169, 155 Ratio: 1.09	8	1,095	7.3
Flatiron	Loveland, CO	9	1954	1	1	upstream	298, 153 Ratio: 1.95		7,392	25.5
Gianelli San Luis	Los Banos, CA	400	1968	8	4	none	324, 117 Ratio: 2.77	1,274	2,146	10.9
Grand Coulee	Grand Coulee, WA	314	1973	6	6	none	363, 267 Ratio: 1.36	35	716	2.7
Helms	Shaver Lake, CA	1,206	1984	3	1	upstream and downstream	1,745, 1,470 Ratio: 1.19	153	19,803	12.3

Table 2-1. Summary of Plant Data

Plant Name	Plant Location: Nearest Town, State	Plant Capacity MW	First Commercial Power	Number of Reversible Units	Number of Main Conduits	Surge Tanks	Static Head: Max, Min (ft) Max/Min Ratio	Storage Capacity Generation Hours	Length of Waterways ft	L/H Ratio
Hiwassee-Unit 2	Murphy, NC	68	1956	1	1	none	255, 173 Ratio: 1.47	4,228	190	1.0
Horse Mesa #4	Tortilla Flat, AZ	97	1972	1	1	none	258, 236 Ratio: 1.10	245	187	0.8
Jocassee	Salem, SC	610	1973	4	4	none	335, 310 Ratio: 1.08	94	1,636	5.0
Kinzua Seneca	Warren, PA	350	1970	2	2	none	813, 644 Ratio: 1.26	11	2,802	4.3
Lewiston	Lewiston, NY	240	1961	12	12	none	113, 66 Ratio: 1.71	20	152	2.0
Ludington	Ludington, MI	1,979	1973	6	6	none	364, 295 Ratio: 1.23	9	1,299	3.6
Mormon Flat #2	Tortilla Flat, AZ	47	1971	1	1	none	139, 126 Ratio: 1.10	59	175	1.4
Mt. Elbert	Leadville, CO	200	1981	2	2	upstream	475, 400 Ratio: 1.19	12	3,000	6.7
Muddy Run	Drumore, PA	800	1967	8	8	none	415, 361 Ratio: 1.15	14	1,290	3.7
Northfield Mountain	Northfield & Erving, MA	1,080	1972	4	4	upstream and downstream	828, 735 Ratio: 1.13	10	6,320	8.5
Raccoon Mountain	Chattanooga, TN	1,530	1978	4	4	downstream	1,042, 900 Ratio: 1.16	21	3,600	4.0
Rocky Mountain	Armuchee, GA	760	1995	3	3	none	690, 613 Ratio: 1.13	8	2,984	4.6
Rocky River	New Milford, CT	32	1929	1	1	upstream	230, 210 Ratio: 1.10	837	1,677	7.5
Richard G. Russel	Elberton, GA	360	1987	4	4	none				
Salina	Salina, OK	260	1968	6	6	none	245, 225 Ratio: 1.09	10	640	2.8
Smith Mountain	Sandy Level, VA	240	1965	3	3	none	195, 174 Ratio: 1.12	14	170	0.9
Taum Sauk	St. Louis, MO	350	1963	2	2	none	875, 764 Ratio: 1.15	8	7,250	9.2
Thermalito	Oroville, CA	115	1968	4	4	none	101, 85 Ratio: 1.19		118	1.3

Table 2-1. Summary of Plant Data

Plant Name	Plant Location: Nearest Town, State	Plant Capacity MW	First Commercial Power	Number of Reversible Units	Number of Main Conduits	Surge Tanks	Static Head: Max, Min (ft) Max/Min Ratio	Storage Capacity Generation Hours	Length of Waterways ft	L/H Ratio
Wallace	Eatonton, GA	209	1979	4	6	none	96, 89 Ratio: 1.08	1,020	172	1.8
Yards Creek	Blairstown, NJ	360	1965	3	1	none	760, 688 Ratio: 1.11	8	3,500	4.8

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Based on preliminary site characteristics, some sites were optimized to better meet evaluation criteria. For example, Option 5G for the Trinity site initially had a large dam volume and resulting installed capacity (MW). The installed capacity was likely larger than needed for power demands; therefore, the Option 5G was optimized to include a reduced dam volume and installed capacity. Option 5G2-A for the Trinity Site moved forward for the second screening step.

During the technical screening, the project team also determined that Concept 3 (installing a new pumping set) would be less effective than Concept 4 (installing new pump-generation sets). The costs to install pump-generation sets are similar to pump sets without providing any incremental increase in generation, so costs would not be a significant differentiator among the two concepts. Therefore, remaining Concept 3 options were screened out from further study.

Tables 2-2 through 2-5 summarize the preliminary site characteristics and technical screening results. Options that passed the technical screening move forward to the second screening step, which includes performing cost opinions, conceptual layouts, operations, environmental, regulatory and economic screening. Based on the technical screening, 14 of the initial 46 options are carried forward to the second screening step. Tables 2-2 through 2-5, in the footnotes, identify why sites were screened out of the analysis. The 14 remaining options include the following:

Yellowtail Site: Four options are moving forward for the Yellowtail site: two Concept 5 options and two Concept 4 options.

Option 5A – This option proposes a new upper reservoir on the northwest side of Bighorn Lake. The new reservoir would connect to Bighorn Lake via a 7,812 foot conductor. The new reservoir would have a minimum elevation of 5,100 feet mean sea level (msl), a maximum elevation of 5,260 feet msl, a dam height of 298 feet, and a dam volume of 7.7 million cubic yards. The upper reservoir would have a usable volume of approximately 12,000 acre-feet. The static head would be 1,562 feet. Energy storage would be 16,601 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 1,660 MW.

Option 5B – This option proposes a new upper reservoir just to the north of Option 5A proposed reservoir. The new reservoir would connect to Bighorn Lake via a 8,602 foot conductor. The static head would be 1,352 feet. The new Option 5B reservoir would have a minimum elevation of 4,900 feet, a maximum elevation of 5,040 feet, a dam height of 261 feet, and a dam volume of 6.5 million cubic yards. The upper reservoir would have a usable volume of approximately 13,500 acre-feet. Energy storage would be 16,067 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 1,607 MW.

Option 4YA-1 – This option proposes using the existing forebay and afterbay, and adding new pump-generation units and associated infrastructure. For this option, the lower reservoir minimum elevation would be 3,157 feet msl and the maximum elevation would be 3,192 feet msl. This option would connect Yellowtail Afterbay to Bighorn Lake via a 8,602 foot conductor. The static head would be 1,352 feet. This option has an L/H ratio of 5.99, which passes the criteria of less than 12. The minimum head/maximum head ratio is 0.78, just below 0.80 criteria, but close enough to be carried forward based on other site characteristics. The usable volume for this option would be 2,875 acre-feet. Energy storage would be 1,123 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 112 MW.

Option 4YA-2 – This option is the same as 4YA-1, except that it assumes a smaller operating range for Yellowtail Afterbay, which reflects recent operations. For this option, the lower reservoir minimum elevation would be 3,183 feet msl and the maximum elevation would be 3,192 feet msl. The option would connect to Yellowtail Afterbay to Bighorn Lake via a 2,649 foot conductor. The static head would be 431 feet. This option has an L/H ratio of 6.15 and the minimum head/maximum head ratio is 0.82. The usable volume for this option would be 1,413 acre-feet. Energy storage would be 536 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 54 MW.

Pathfinder Site: Two options are moving forward for the Pathfinder site. Both options are Concept 5 options with new upper reservoirs. The Concept 4 option was screened out because of the very high L/H ratio of 95.09.

Option 5A1 – This option proposes a new reservoir that would connect to Pathfinder Reservoir via a 11,482 foot conductor. The new Option 5A1 reservoir would have a minimum elevation of 6,975 feet msl, a maximum elevation of 7,100 feet msl, a dam height of 231 feet, and a dam volume of 3.7 million cubic yards. The upper reservoir would have a usable volume of approximately 5,379 acre-feet. The usable volume of Pathfinder Reservoir is 985,102 acre-feet. The static head would be 1,232 feet. Energy storage would be 5,767 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 577 MW.

Option 5D - This option proposes a new reservoir that would connect to Alcova Reservoir via a 8,746 foot conductor. The new Option 5D reservoir would have a minimum elevation of 6,050 feet msl, a maximum elevation of 6,180 feet msl, a dam height of 269 feet, and a dam volume of 5.7 million cubic yards. The upper reservoir would have a usable volume of approximately 12,950 acre-feet. The usable volume of Alcova Reservoir is 30,603 acre-feet. The static head would be 621 feet. Energy storage would be 7,082 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 708 MW.

Table 2-2. Yellowtail-Yellowtail Afterbay Pumped Storage Project Preliminary Site Characteristics

Assumed Feature (Conceptual)	Option 5A	Option 5B	Option 3YA-1	Option 3YA-2	Option 4YA-1	Option 4YA-2	Yellowtail	Yellowtail Afterbay 1	Yellowtail Afterbay 2
Potential Concept Study Candidate	Yes	Yes	No	No	Yes	Yes			
Max Upper Reservoir Elev (msl)	5,260	5,040	3,657	3,657	3,657	3,657	3,657		
Min Upper Reservoir Elev (msl)	5,100	4,900	3,580	3,580	3,580	3,580	3,580		
Estimated Dam Volume (CY)	7,734,313	6,499,188							
Lower Reservoir Maximum Elev (msl)	3,657	3,657	3,192	3,192	3,192	3,192	3,657	3,192	3,192
Lower Reservoir Minimum Elev (msl)	3,580	3,580	3,157	3,183	3,157	3,183	3,580	3,157	3,183
Upper Reservoir Drawdown (ft)	160	140	77	77	77	77			
Min Head / Max Head Ratio (>.80)	0.86	0.85	0.78	0.82	0.78	0.82			
Approx. Static Head (ft) (<2650 ft)	1,562	1,352	444	431	444	431			
Maximum Dam Height (ft) (<400ft)	298	261							
Horiz. Dist. Intake-Discharge (ft)	6,250	7,250	2,218	2,218	2,218	2,218			
Required Submergence Below TW (ft)	168	146	50	47	50	47			
Est. Conductor Length (L)	7,812	8,602	2,662	2,649	2,662	2,649			
Conductor Length (L) / Static Head (H)	5.00	6.36	5.99	6.15	5.99	6.15			
L/H General Acceptance Criteria	< 12	< 12	< 7	< 7	< 7	< 7			
Upper Reservoir Usable Vol (acre-ft)	12,081	13,509	2,875	1,413	2,875	1,413			
Lower Reservoir Usable Vol (acre-ft)	336,103	336,103	2,875	1,413	2,875	1,413	336,103	2,875	1,413
Energy Storage (MWh)	16,601	16,067	1,123	536	1,123	536			
Assumed Hours of Storage	10	10	10	11	10	10			
Resulting Installed Capacity (MW)	1,660	1,607	112	49	112	54			
Assumed Hours of Storage	20	20	20	21	20	20			
Resulting Installed Capacity (MW)	830	803	56	26	56	27			
Assumed Hours of Storage	30	30	30	31	30	30			
Resulting Installed Capacity (MW)	553	536	37	17	37	18			
Assumed Hours of Storage	40	40	40	41	40	40			
Resulting Installed Capacity (MW)	415	402	28	13	28	13			

Notes: Color coding in the Options title block indicate the lower reservoir (i.e., Brown – Yellowtail/Bighorn Lake is the lower reservoir)
5A: Selected for further study
5B: Selected for further study
3YA-1: Not selected for further study because Concept 3 was screened out relative to Concept 4
3YA-2: Not selected for further study because Concept 3 was screened out relative to Concept 4
4YA-1: Selected for further study
4YA-2: Selected for further study

Table 2-3. Pathfinder-Alcova Pumped Storage Project Preliminary Site Characteristics

Assumed Feature (Conceptual)	Option 5A1	Option 5A2	Option 5B1	Option 5B2	Option 5C1-A	Option 5C1-B	Option 5C1-C	Option 5C1-D	Option 5C2	Option 5D	Option 5E	Option 3PA-A	Option 4PA-A	Option 3PA-B	Option 4PA-B	Option 3PA-C	Option 4PA-C	Pathfinder	Alcova
Potential Concept Study Candidate	Yes	No	No	No	No	No	No	No	No	Yes	No	No	No	No	No	No	No		
Max Upper Reservoir Elev (msl)	7,100	7,000	6,200	6,400	6,300	6,300	6,300	6,300	6,360	6,180	6,100	5,850	5,850	5,850	5,850	5,850	5,850	5,850	
Min Upper Reservoir Elev (msl)	6,975	6,875	6,075	6,320	6,240	6,240	6,240	6,240	6,300	6,050	6,000	5,760	5,760	5,760	5,760	5,760	5,760	5,760	
Estimated Dam Volume (CY)	3,671,836	3,360,407	3,993,322	7,518,403	726,310	726,310	726,310	726,310	1,807,442	5,716,670	2,075,847								
Lower Reservoir Maximum Elev (msl)	5,850	5,850	5,850	5,850	5,500	5,500	5,500	5,850	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,850	5,500
Lower Reservoir Minimum Elev (msl)	5,760	5,760	5,760	5,760	5,487	5,487	5,487	5,760	5,487	5,487	5,487	5,487	5,487	5,487	5,487	5,487	5,487	5,760	5,487
Upper Reservoir Drawdown (ft)	125	125	125	80	60	60	60	60	60	130	100	90	90	90	90	90	90		
Min Head / Max Head Ratio (>.80)	0.84	0.83	0.51	0.73	0.91	0.91	0.91	0.72	0.92	0.79	0.82	0.72	0.72	0.72	0.72	0.72	0.72		
Approx. Static Head (ft) (<2650 ft)	1,232	1,132	332	555	776	776	776	465	836	621	556	311	311	311	311	311	311		
Maximum Dam Height (ft) (<400ft)	231	220	215	315	122	122	122	122	113	269	246								
Horiz. Dist. Intake-Discharge (ft)	10,250	11,000	2,625	3,250	17,000	10,771	9,662	14,309	9,625	8,125	12,250	29,304	29,304	21,701	21,701	16,526	16,526		
Required Submergence Below TW (ft)	134	124	44	64	81	81	81	54	87	69	61	36	36	36	36	36	36		
Est. Conductor Length (L)	11,482	12,132	2,957	3,805	17,776	11,548	10,439	14,774	10,461	8,746	12,806	29,615	29,615	22,012	22,012	16,838	16,838		
Conductor Length (L) / Static Head (H)	9.32	10.71	8.90	6.86	22.89	14.87	13.44	31.77	12.51	14.07	23.01	95.09	95.09	70.68	70.68	54.06	54.06		
L/H General Acceptance Criteria	< 12	< 12	< 7	< 10	< 12	< 12	< 12	< 7	< 12	< 10	< 10	< 7	< 7	< 7	< 7	< 7	< 7		
Upper Reservoir Usable Vol (acre-ft)	5,297	5,446	9,952	4,926	3,529	3,529	3,529	3,529	3,946	12,950	10,856	30,603	30,603	30,603	30,603	30,603	30,603		
Lower Reservoir Usable Vol (acre-ft)	985,102	985,102	985,102	985,102	30,603	30,603	30,603	985,102	30,603	30,603	30,603	30,603	30,603	30,603	30,603	30,603	30,603	985,102	30,603
Energy Storage (MWh)	5,745	5,428	2,912	2,406	2,411	2,411	2,411	1,444	2,905	7,082	5,316	8,388	8,388	8,388	8,388	8,388	8,388		
Assumed Hours of Storage	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10		
Resulting Installed Capacity (MW)	575	543	291	241	241	241	241	144	290	708	532	839	839	839	839	839	839		
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)	287	271	146	120	121	121	121	72	145	354	266	419	419	419	419	419	419		
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)	192	181	97	80	80	80	80	48	97	236	177	280	280	280	280	280	280		
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)	144	136	73	60	60	60	60	36	73	177	133	210	210	210	210	210	210		

Notes: Color coding in the Options title block indicate the lower reservoir
5A1: Selected for further study
5A2: Not selected for further study
5B1: Not selected for further study because of min head / max head ratio
5B2: Not selected for further study because of small installed capacity in relation to dam volume size
5C1-A: Not selected for further study because of depth in lower river reach and L/H ratio
5C1-B: Not selected for further study because of depth in lower river reach and L/H ratio
5C1-C: Not selected for further study because of depth in lower river reach and L/H ratio
5C1-D: Not selected for further study because of L/H ratio
5C2: Not selected for further study because of depth in lower river reach
5D: Selected for further study
5E: Not selected for further study because of L/H ratio
3PA-A: Not selected for further study because of L/H ratio
4PA-A: Not selected for further study because of L/H ratio
3PA-B: Not selected for further study because of L/H ratio
4PA-B: Not selected for further study because of L/H ratio
3PA-C: Not selected for further study because of L/H ratio
4PA-C: Not selected for further study because of L/H ratio

Table 2-4. Seminoe-Kortes Pumped Storage Project Preliminary Site Characteristics

Assumed Feature (Conceptual)	Option 5A1	Option 5A2	Option 5B	Option 5C	Option 5D1	Option 5D2	Option 3SK	Option 4SK	Seminoe	Kortes
Potential Concept Study Candidate	Yes	Yes	No	Yes	Yes	No	No	No		
Max Upper Reservoir Elev (msl)	7,180	7,280	7,370	7,300	7,310	7,200	6,357	6,357	6,357	
Min Upper Reservoir Elev (msl)	7,104	7,104	7,342	7,165	7,175	7,025	6,290	6,290	6,290	
Estimated Dam Volume (CY)	4,688,429	9,756,673	8,539,194	8,430,094	1,899,238	2,834,602				
Lower Reservoir Maximum Elev (msl)	6,142	6357	6,142	6,357	6,142	6,142	6,142	6,142	6,357	6,142
Lower Reservoir Minimum Elev (msl)	6,092	6290	6,092	6,290	6,092	6,092	6,092	6,092	6,290	6,092
Upper Reservoir Drawdown (ft)	76	176	28	135	135	175	67	67		
Min Head / Max Head Ratio (>.80)	0.88	0.75	0.94	0.80	0.85	0.80	0.56	0.56		
Approx. Static Head (ft) (<2650 ft)	1,025	869	1,239	909	1,126	996	207	207		
Maximum Dam Height (ft) (<400ft)	297	397	386	336	216	280				
Horiz. Dist. Intake-Discharge (ft)	6,500	8,000	8,000	5,375	4,375	4,000	3,500	3,500		
Required Submergence Below TW (ft)	109	99	128	101	122	111	27	27		
Est. Conductor Length (L)	7,525	8869	9,239	6,284	5,501	4,996	3,707	3,707		
Conductor Length (L) / Static Head (H)	7.34	10.21	7.46	6.91	4.89	5.02	17.95	17.95		
L/H General Acceptance Criteria	< 12	< 12	< 12	< 12	< 12	< 12	< 5	< 5		
Upper Reservoir Usable Vol (acre-ft)	3,068	10,119	2,956	7,145	2,689	2,812	3,073	3,073		
Lower Reservoir Usable Vol (acre-ft)	3,073	985,603	3,073	985,603	3,073	3,073	3,073	3,073	985,603	3,073
Energy Storage (MWh)	2,767	7734	3,223	5,715	2,664	2,464	559	559		
Assumed Hours of Storage	10	10	10	10	10	10	10	10		
Resulting Installed Capacity (MW)	277	773	322	572	266	246	56	56		
Assumed Hours of Storage	20	20	20	20	20	20	20	20		
Resulting Installed Capacity (MW)	138	387	161	286	133	123	28	28		
Assumed Hours of Storage	30	30	30	30	30	30	30	30		
Resulting Installed Capacity (MW)	92	258	107	191	89	82	19	19		
Assumed Hours of Storage	40	40	40	40	40	40	40	40		
Resulting Installed Capacity (MW)	69	193	81	143	67	62	14	14		

Notes: Color coding in the Options title block indicate the lower reservoir
5A1: Selected for further study, but would require stream augmentation at 500 cfs
5A2: Selected for further study
5B: Not selected for further study because of small installed capacity in relation to a large dam volume
5C: Selected for further study
5D1: Selected for further study, but would require stream augmentation at 500 cfs
5D2: Not selected for further study
3SK: Not selected for further study because of small min head/ max head ratio and L/H ratio
4SK: Not selected for further study because of small min head/ max head ratio and L/H ratio

Table 2-5. Trinity-Lewiston Pumped Storage Project Preliminary Site Characteristics

Assumed Feature (Conceptual)	Option 5A-A	Option 5A-B	Option 5B-A	Option 5B-B	Option 5C-A	Option 5C-B	Option 5D	Option 5E	Option 5F	Option 5G	Option 5G2	Option 5G2-A	Option 5H	Option 3TL	Option 4TL	Trinity	Lewiston
Potential Concept Study Candidate	No	Yes	No	No	No	No	No	No	Yes	No	No	Yes	No	No	Yes		
Max Upper Reservoir Elev (msl)	2,940	2,940	3,084	3,084	2,671	2,671	3,030	3,340	4,170	3,300	3,105	3,105	2,580	2,370	2,370	2,370	
Min Upper Reservoir Elev (msl)	2,900	2,900	3,000	3,000	2,608	2,608	2,936	3,285	4,130	3,200	3,015	3,015	2,562	2,235	2,235	2,200	
Estimated Dam Volume (CY)	7,837,254	7,837,254	11,765,487	11,765,487	2,792,187	2,792,187	6,936,584	6,470,080	2,990,932	24,146,761	4,025,634	4,025,634	9,315,334				
Lower Reservoir Maximum Elev (msl)	2,370	2,370	2,370	2,370	1,904	1,904	1,904	1,904	1,904	2,370	2,370	2,370	1,904	1,904	1,904	2,370	1,904
Lower Reservoir Minimum Elev (msl)	2,200	2,200	2,200	2,200	1,900	1,900	1,900	1,900	1,900	2,200	2,200	2,200	1,900	1,900	1,900	2,200	1,900
Upper Reservoir Drawdown (ft)	40	40	84	84	63	63	94	55	40	100	90	90	18	135	135		
Min Head / Max Head Ratio (>.80)	0.72	0.72	0.71	0.71	0.91	0.91	0.91	0.96	0.98	0.75	0.71	0.71	0.97	0.70	0.70		
Approx. Static Head (ft) (<2650 ft)	635	635	757	757	738	738	1,081	1,411	2,248	965	775	775	669	401	401		
Maximum Dam Height (ft) (<400ft)	377	377	349	349	232	232	340	376	278	334	139	139	383				
Horiz. Dist. Intake-Discharge (ft)	3,907	8,976	11,352	7,392	10,877	10,930	11,750	19,500	19,125	6,500	6,500	6,336	8,500	4,277	4,277		
Required Submergence Below TW (ft)	74	74	88	88	77	77	113	144	227	110	91	91	68	47	47		
Est. Conductor Length (L)	4,542	9,611	12,109	8,149	11,614	11,667	12,831	20,911	21,373	7,465	7,275	7,111	9,169	4,677	4,677		
Conductor Length (L) / Static Head (H)	7.15	15.14	16.00	10.76	15.75	15.82	11.87	14.82	9.51	7.74	9.39	9.18	13.71	11.68	11.68		
L/H General Acceptance Criteria	< 10	< 10	< 12	< 12	< 10	< 10	< 12	< 12	< 12	< 12	< 12	< 12	< 10	< 7	< 7		
Upper Reservoir Usable Vol (acre-ft)	13,697	13,697	16,577	16,577	3,125	3,125	3,141	3,131	3,109	40,015	15,022	15,022	3,043	3,154	3,154		
Lower Reservoir Usable Vol (acre-ft)	1,859,688	1,859,688	1,859,688	1,859,688	3,154	3,154	3,154	3,154	3,154	1,859,688	1,859,688	1,859,688	3,154	3,154	3,154	1,859,688	3,154
Energy Storage (MWh)	7,654	7,654	11,043	11,043	2,028	2,028	2,988	3,886	6,151	33,980	10,245	10,245	1,791	1,112	1,112		
Assumed Hours of Storage	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10		
Resulting Installed Capacity (MW)	765	765	1,104	1,104	203	203	299	389	615	3,398	1,024	1,024	179	111	111		
Assumed Hours of Storage	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20		
Resulting Installed Capacity (MW)	383	383	552	552	101	101	149	194	308	1,699	512	512	90	56	56		
Assumed Hours of Storage	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30		
Resulting Installed Capacity (MW)	255	255	368	368	68	68	100	130	205	1,133	341	341	60	37	37		
Assumed Hours of Storage	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40		
Resulting Installed Capacity (MW)	191	191	276	276	51	51	75	97	154	850	256	256	45	28	28		

Notes: Color coding in the Options title block indicate the lower reservoir
5A-A: Not selected for further study because of lack of depth in cove
5A-B: Selected for further study
5B-A: Not selected for further study because of large L/H ratio
5B-B: Not selected for further study because of lack of depth in cove
5C-A: Not selected for further study because of small output size and large L/H ratio
5C-B: Not selected for further study because of small output size and large L/H ratio
5D: Not selected for further study because of large dam size and small output
5E: Not selected for further study
5F: Selected for further study
5G: Not selected for further study because site has been optimized
5G2: Not selected for further study because site has been optimized
5G2-A: Selected for further study as optimized site
5H: Not selected for further study because of large dam size and small output
3TL: Not selected for further study because Concept 3 was screened out relative to Concept 4
4TL: Selected for further study

Seminoe Site: Four options are moving forward for the Seminoe site. All options are Concept 5 options with new upper reservoirs. The Concept 4 option was screened out because of the high L/H ratio of 17.95 and low minimum head/maximum head ratio of 0.56.

Option 5A1 - This option proposes a new reservoir that would connect to Kortes Reservoir via a 7,525 foot conductor. The new upper reservoir would have a minimum elevation of 7,104 feet msl, a maximum elevation of 7,180 feet msl, a dam height of 297 feet, and a dam volume of 4.7 million cubic yards. The upper reservoir would have a usable volume of approximately 3,068 acre-feet. The usable volume of Kortes Reservoir is 3,073 acre-feet. The static head would be 1,025 feet. Energy storage would be 2,767 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 277 MW. This option requires a new stream augmentation to continue minimum flow releases of 500 cfs from Kortes Reservoir into the North Platte River for fishery purposes.

Option 5A2 - This option proposes a new reservoir that would connect to Seminoe Reservoir via a 8869 foot conductor. The new upper reservoir would have a minimum elevation of 7,104 feet msl, a maximum elevation of 7,280 feet msl, a dam height of 397 feet, and a dam volume of 9.7 million cubic yards. The upper reservoir would have a usable volume of approximately 10,119 acre-feet. The usable volume of Seminoe Reservoir is 985,603 acre-feet. The static head would be 869 feet. Energy storage would be 7734 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 773 MW.

Option 5C - This option proposes a new reservoir that would connect to Seminoe Reservoir via a 6,284 foot conductor. The new upper reservoir would have a minimum elevation of 7,165 feet msl, a maximum elevation of 7,300 feet msl, a dam height of 336 feet, and a dam volume of 8.4 million cubic yards. The upper reservoir would have a usable volume of approximately 7,145 acre-feet. The usable volume of Seminoe Reservoir is 985,603 acre-feet. The static head would be 909 feet. Energy storage would be 5,715 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 572 MW.

Option 5D1 - This option proposes a new reservoir that would connect to Kortes Reservoir via a 5,501 foot conductor. The new upper reservoir would have a minimum elevation of 7,175 feet msl, a maximum elevation of 7,310 feet msl, a dam height of 216 feet, and a dam volume of 1.9 million cubic yards. The upper reservoir would have a usable volume of approximately 2,689 acre-feet. The usable volume of Kortes Reservoir is 3,073 acre-feet. The static head would be 1,126 feet. Energy storage would be 2,664 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 266 MW. This option requires a new stream augmentation to continue minimum flow releases of 500 cfs from Kortes Reservoir into the North Platte River for fishery purposes.

Trinity Site: Four options are moving forward for the Trinity site, three Concept 5 options and one Concept 4 option.

Option 5A-B - This option proposes a new reservoir that would connect to Trinity Reservoir via a 9,611 foot conductor. The new upper reservoir would have a minimum elevation of 2,900 feet msl, a maximum elevation of 2,940 feet msl, a dam height of 377 feet, and a dam volume of 7.8 million cubic yards. The upper reservoir would have a usable volume of approximately 13,697 acre-feet. The usable volume of Trinity Reservoir is 1.8 million acre-feet. The static head would be 635 feet. Energy storage would be 7,654 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 765 MW.

Option 5F - This option proposes a new reservoir that would connect to Lewiston Reservoir via a 21,373 foot conductor. The new upper reservoir would have a minimum elevation of 4,130 feet msl, a maximum elevation of 4,170 feet msl, a dam height of 278 feet, and a dam volume of 2.9 million cubic yards. The upper reservoir would have a usable volume of approximately 3,109 acre-feet. The usable volume of Lewiston Reservoir is 3,154 acre-feet. The static head would be 2,248 feet. Energy storage would be 6,151 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 615 MW.

Option 5G2-A - This option proposes a new reservoir that would connect to Trinity Reservoir via a 7,111 foot conductor. The new upper reservoir would have a minimum elevation of 3,015 feet msl, a maximum elevation of 3,105 feet msl, a dam height of 139 feet, and a dam volume of 4.0 million cubic yards. The upper reservoir would have a usable volume of approximately 15,022 acre-feet. The usable volume of Trinity Reservoir is 1.8 million acre-feet. The static head would be 775 feet. Energy storage would be 1,024 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 765 MW.

Option 4TL - This option proposes using the existing forebay and afterbay, and adding new pump-generation units and associated infrastructure. For this option, a 4,677 foot conductor would be installed on the west side of Trinity Dam to the upstream end of Lewiston Reservoir. The static head would be 401 feet. The usable volume for this option would be 3,154 acre-feet, which is also the usable volume of Lewiston Reservoir. Energy storage would be 1,112 MWh. Assuming 10 hours of storage, the resulting installed capacity would be 111 MW.

Chapter 3
Conceptual Layout and Cost Evaluation Studies

3.1 General Procedures and Assumptions

The primary objectives of this task were to utilize the project information generated to date and develop conceptual layouts for each of the options, including sizing, performing quantity take-offs, and generating Class 5 cost opinions for the following major project elements:

- Reservoirs and dams
- Water conveyance systems
- Powerstation and associated equipment (assuming single-speed unit technology)
- Switchyard and transmission facilities
- Project access

It should be noted that these costs only represent an American Association of Cost Estimating (AACE) Class 5 cost opinion based on very conceptual layout information and derived from cost curves provided by EPRI's Pumped Storage Planning and Evaluation Guide, escalated to 2012 dollars. The primary resource utilized for this task included the EPRI Document No. GS-6669 (1990). Because the cost estimating tools are based on 1988 pricings, all cost estimates were indexed to 2012 dollars using an escalation an average escalation factor of 3.0.

3.2 Reservoirs and Dams

3.2.1 Reservoirs

The project team considered various upper reservoir configurations and locations, including area-volume curves, dam profiles, and area-volume data. Reservoirs for each option were sized using methods discussed in Section 2 of this report. Reservoir drawdown limits were assumed limited to approximately 30 percent of the static head, which is common for pump-turbine operational restrictions and acceptable for the dam structures identified below.

3.2.2 Dams

For the purpose of this study, all dams associated with Concept 5 were assumed to be rockfill concrete face type. Material take-off estimates were performed for each dam structure assuming a crest elevation 10 feet higher than the maximum reservoir elevation as well as upstream and downstream slopes of 1.75H:1.0V. Dam heights were increased by an additional 20 feet to account for foundation and abutment stripping, and other factors.

Table 3-1 lists the estimated earthwork volumes and construction costs for each option. For medium to large dams, Figure 6-10 in EPRI Document No. GS-6669 (1990) indicates a 1988 unit cost in the order of $8/cubic yard (CY). Assuming an index factor of 3.0, this calculates to a 2012 unit cost of approximately $24/CY.

Table 3-1. Estimated Earthwork Volumes and Construction Costs

Development	Option	Approx. Max Dam Height (ft)	Estimated Volume (CY)	1988 Est. Unit Costs ($/CY)	Index Factor	2012 Total Est. Costs ($)
Yellowtail-Yellowtail Afterbay	5A	298	7,734,313	7.60	3	176,342,336
	5B	261	6,499,188	7.65	3	149,156,365
	4YA-1					-
	4YA-2					-
Pathfinder-Alcova	5A1	231	3,671,836	7.80	3	85,920,962
	5D	269	5,716,670	7.70	3	132,055,077
Seminoe-Kortes	5A1	297	4,688,429	7.70	3	108,302,710
	5A2	397	9,756,673	7.50	3	219,525,143
	5C	336	8,430,094	7.55	3	190,941,629
	5D1	216	1,899,238	8.25	3	47,006,141
Trinity-Lewiston	5A-B	232	7,837,254	7.60	3	178,689,391
	5F	278	2,990,932	7.80	3	69,987,809
	5G2-A	139	4,025,634	7.75	3	93,595,991
	4TL					-

3.2.3 Stream Diversion

The project team assumed a stream diversion system would be installed to divert flows during construction of the upper reservoir main dam. For the purpose of this estimate, $5,000,000 was allocated for the installation of a stream diversion system.

3.2.4 Spillway

There is very little drainage area associated with the impoundment of the upper reservoir, and therefore no major spillway was assumed necessary for the purpose of passing a probable maximum flood. To protect the impoundments against the possibility of over-pumping, $5,000,000 was allocated for the construction of the spillway.

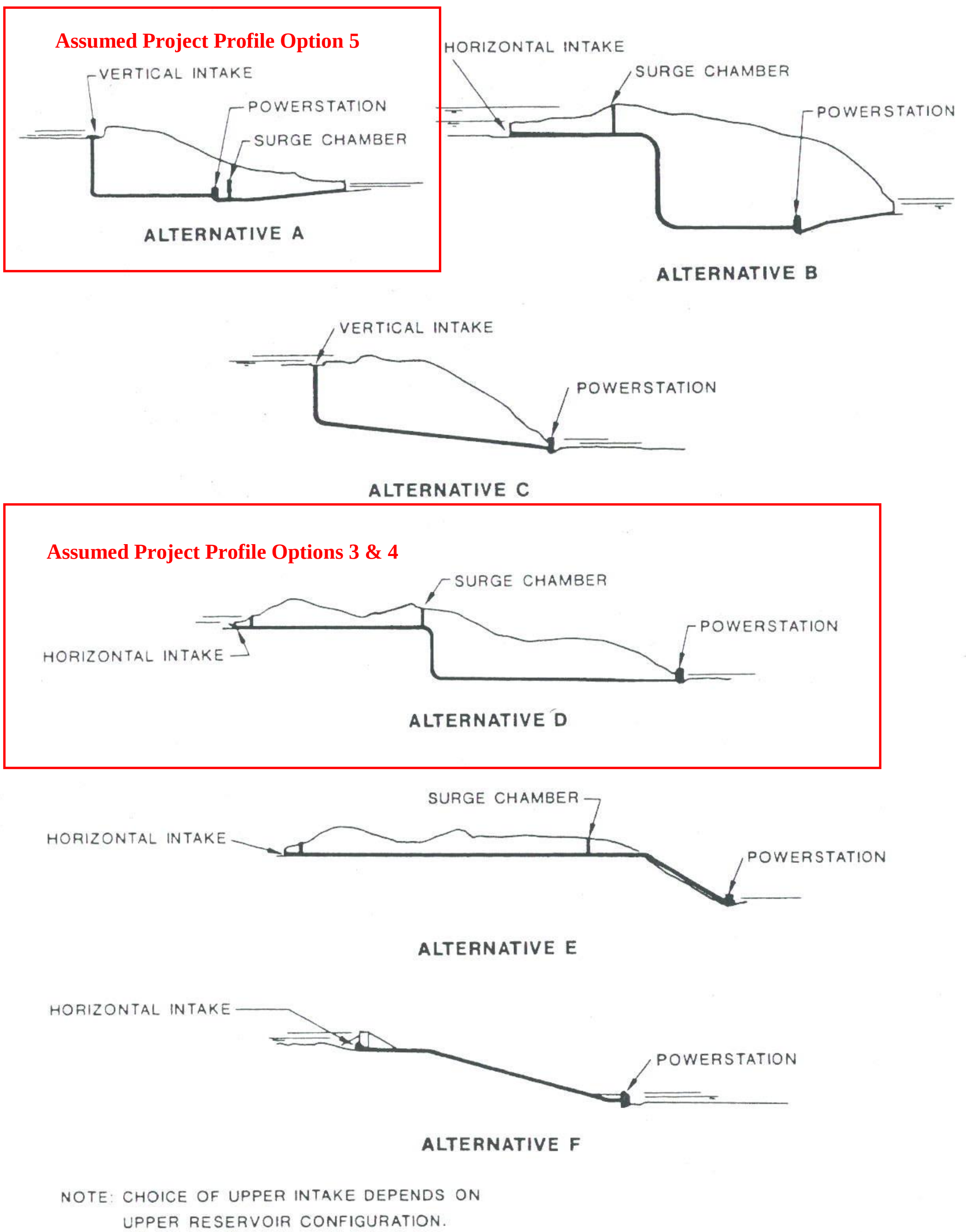
3.3 Powerstation Structure

Table 3-2 lists powerstation construction costs for each option. As shown in Figure 3-1, Concept 5 options assume an underground structure, whereas Concepts 3 and 4 assume surface structures on the lower reservoir. The unit costs were derived from Figures 6-8 through 6-9 of EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0 assuming single-speed unit technology. Estimated equipment costs are provided in Section 3.4.12 of this report.

Table 3-2. Powerstation Construction Costs

Development	Option	Assumed Static Head (ft)	Installed Capacity (MW)	No. Units	MW per Unit	1988 Unit Costs ($/kW)	Index Factor	2012 Total Est. Costs ($)
Yellowtail-Yellowtail Afterbay	5A	1,562	1,660	4	415	30	3	149,408,672
	5B	1,352	1,607	4	402	38	3	183,160,270
	4YA-1	444	112	2	56	86	3	28,981,656
	4YA-2	431	54	2	27	95	3	15,273,795
Pathfinder-Alcova	5A1	1,232	575	2	287	50	3	86,180,392
	5D	621	708	4	177	66	3	140,228,698
Seminoe-Kortes	5A1	1,025	277	2	138	68	3	56,444,822
	5A2	869	773	4	193	58	3	134,571,361
	5C	909	572	2	286	58	3	99,447,716
	5D1	1,126	266	2	133	67	3	53,540,952
Trinity-Lewiston	5A-B	635	765	3	255	75	3	172,212,381
	5F	2,248	615	2	308	37	3	68,271,280
	5G2-A	775	1,024	4	256	54	3	165,968,402
	4TL	401	111	2	56	86	3	28,679,171

Figure 3-1. Alternative Pumped Storage Project Profiles



3.4 Water Conveyance, Equipment, Transmission, and Other Civil Works

3.4.1 Profile Assumptions

The water conveyance profile was assumed to consist of a vertical intake/shaft, horizontal power tunnel, underground powerstation, draft tube tunnels, and tailrace tunnels. All tunnels were assumed to be fully lined with concrete.

3.4.2 Water Conductor Sizing Assumptions

3.4.2.1 Generating Discharge

The generating discharge is calculated as follows:

$$Q = 11{,}800\ C/He$$

Where: Q = Design Generating Discharge (cfs)
C = Rated Generating Capacity (MW)
H = Gross Head (ft)
e = Overall Generating Efficiency (assumed 0.86)

3.4.2.2 Flow Velocity

The water velocity within the water conveyance system is estimated by the equation below and then used to compute the tunnel diameter:

V = 90 H/L (for water conveyance systems with surge chamber)

V = 120 H/L (for water conveyance systems without surge chamber)

3.4.2.3 Tunnel Diameter

The water conductor diameter is estimated using the following relationship:

$$D = (1.273\ Q/V)^{0.5}$$

Where: D = Water Conductor Diameter (ft)
Q = Generating Discharge (cfs)
V = Generating Velocity (ft/sec)

For tunnel diameters greater than 35 feet, an additional tunnel is recommended. The resulting water conveyance characteristics for each option are shown in Table 3-3. Cost elements are provided in the following sections.

Table 3-3. Water Conveyance Characteristics

Development	Option	General Site Characteristics				Water Conveyance System - Preliminary Characteristics							
		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
Yellowtail-Yellowtail Afterbay	5A	1,660	1,562	7,812	14,586	30	1	13	4	18	4	25	2
	5B	1,607	1,352	8,602	16,310	32	1	14	4	20	4	26	2
	3YA-1	112	444	2,662	3,471	15	1	11	2	17	2		
	3YA-2	49	431	2,649	1,551	10	1	7	2	11	2		
	4YA-1	112	444	2,662	3,471	15	1	11	2				
	4YA-2	54	431	2,649	1,706	10	1	8	2				
Pathfinder - Alcova	5A1	575	1,232	11,482	6,396	20	1	13	2	18	2	23	1
	5A2	543	1,132	12,132	6,576	20	1	13	2	18	2	24	1
	5B1	291	332	2,957	12,016	28	1	21	2	31	2	32	1
	5B2	241	555	3,805	5,947	19	1	14	2	19	2	22	1
	5C1-A	241	776	17,776	4,260	16	1	12	2	16	2	19	1
	5C1-B	241	776	11,548	4,260	16	1	12	2	16	2	19	1
	5C1-C	241	776	10,439	4,260	16	1	12	2	16	2	19	1
	5C1-D	144	465	14,774	4,260	16	1	12	2	18	2	19	1
	5C2	290	836	10,461	4,765	17	1	12	2	17	2	20	1
	5D	708	621	8,746	15,636	32	1	16	4	22	4	26	2
	5E	532	556	12,806	13,107	29	1	20	2	29	2	33	1
	3PA-A	839	311	29,615	36,949	34	2	26	4	38	4		
	4PA-A	839	311	29,615	36,949	34	2	26	4	38	4		
	3PA-B	839	311	22,012	36,949	34	2	26	4	38	4		
	4PA-B	839	311	22,012	36,949	34	2	26	4	38	4		
	3PA-C	839	311	16,838	36,949	34	2	26	4	38	4		
	4PA-C	839	311	16,838	36,949	34	2	26	4	38	4		

Table 3-3. Water Conveyance Characteristics

Development	Option	General Site Characteristics				Water Conveyance System - Preliminary Characteristics							
		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
Seminoe - Kortes	5A1	277	1,025	7,525	3,704	15	1	10	2	13	2	18	1
	5A2	773	869	8,869	12,218	28	1	12	4	20	4	23	2
	5B	322	1,239	9,239	3,569	15	1	10	2	13	2	17	1
	5C	572	909	6,284	8,627	23	1	17	2	23	2	27	1
	5D1	266	1,126	5,501	3,247	14	1	9	2	13	2	17	1
	5D2	246	996	4,996	3,395	15	1	10	2	15	2	17	1
	3SK	56	207	3,707	3,710	15	1	17	1	28	1		
	4SK	56	207	3,707	3,710	15	1	17	1	28	1		
Trinity - Lewiston	5A-A	765	635	4,542	16,537	32	1	19	3	26	3	37	1
	5A-B	765	635	9,611	16,537	32	1	19	3	26	3	37	1
	5B-A	1,104	757	12,109	20,014	25	2	18	4	25	4	29	2
	5B-B	1,104	757	8,149	20,014	25	2	18	4	25	4	29	2
	5C-A	1,104	738	11,614	20,543	26	2	18	4	26	4	30	2
	5C-B	203	738	11,667	3,773	15	1	11	2	15	2	18	1
	5D	299	1,081	12,831	3,792	16	1	10	2	14	2	18	1
	5E	389	1,411	20,911	3,780	16	1	10	2	14	2	18	1
	5F	615	2,248	21,373	3,754	15	1	9	2	12	2	18	1
	5G	3,398	965	7,465	48,312	32	3	18	9	26	9	37	3
	5G2	1,024	775	7,275	18,137	34	1	17	4	24	4	28	2
	5G2-A	1,024	775	7,111	18,137	34	1	17	4	24	4	28	2
	5H	179	669	9,169	3,673	15	1	11	2	15	2	18	1
	3TL	111	401	4,677	3,808	16	1	12	2	17	2		
	4TL	111	401	4,677	3,808	16	1	12	2				

Notes:
[1] Based on a 10-hour run time.

3.4.3 Upper Reservoir Intake

The upper reservoir intake for Concept 5 options was assumed to be a submerged reinforced concrete vertical type bellmouth hooded structure, ungated with no trashracks, and located within a depression to provide sufficient submergence for generation with the reservoir nearly empty. However, the most cost-effective means for isolating the units has yet to be determined. The upper reservoir intake for Concepts 3 and 4 were assumed to be a submerged horizontal intake, gated with trashracks. Table 3-4 lists the costs for intakes. These costs were derived from Figure 6-12 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 3-4. Intake Characteristics and Estimated Costs

Development	Option	No. of Tunnels	Tunnel Diameter (ft)	1988 Est. Unit Costs ($)	Index Factor	2012 Total Est. Costs ($)
Yellowtail-Yellowtail Afterbay	5A	1	30	2,100,000	3	6,300,000
	5B	1	32	2,300,000	3	6,900,000
	4YA-1	1	15	2,500,000	3	7,500,000
	4YA-2	1	10	1,400,000	3	4,200,000
Pathfinder-Alcova	5A1	1	20	750,000	3	2,250,000
	5D	1	32	2,300,000	3	6,900,000
Seminoe-Kortes	5A1	1	15	450,000	3	1,350,000
	5A2	1	28	1,900,000	3	5,700,000
	5C	1	23	1,000,000	3	3,000,000
	5D1	1	14	300,000	3	900,000
Trinity-Lewiston	5A-B	1	32	2,300,000	3	6,900,000
	5F	1	15	450,000	3	1,350,000
	5G2-A	1	34	3,200,000	3	9,600,000
	4TL	1	16	2,750,000	3	8,250,000

3.4.4 Vertical Shaft

A concrete-lined vertical shaft was assumed to extend from the intake structure to the horizontal power tunnel. The shaft height for each option was assumed to be equal to the static head. Table 3-5 lists the costs for the vertical shaft structures for each of the options. The costs were derived from Figure 6-14 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 3-5. Vertical Shaft Structure Characteristics and Estimated Costs

Development	Option	No. of Tunnels	Height of Shaft (ft)	Total Length of Shaft (ft)	Tunnel Diameter (ft)	1988 Est. Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs ($)
Yellowtail-Yellowtail Afterbay	5A	1	1,562	1,562	30	5,700	3	26,701,650
	5B	1	1,352	1,352	32	6,000	3	24,327,000
	4YA-1	1	444	444	15	2,800	3	3,729,600
	4YA-2	1	431	431	10	2,000	3	2,586,000
Pathfinder-Alcova	5A1	1	1,232	1,232	20	3,700	3	13,680,195
	5D	1	621	621	32	6,000	3	11,186,100
Seminoe-Kortes	5A1	1	1,025	1,025	15	2,800	3	8,610,000
	5A2	1	1,075	1,075	28	5,400	3	17,415,000
	5C	1	909	909	23	4,200	3	11,452,770
	5D1	1	1,126	1,126	14	2,600	3	8,778,900
Trinity-Lewiston	5A-B	1	635	635	32	6,000	3	11,430,000
	5F	1	2,248	2,248	15	2,800	3	18,883,200
	5G2-A	1	775	775	34	6,500	3	15,112,500
	4TL	1	401	401	16	3,000	3	3,604,500

3.4.5 Horizontal Power Tunnel

A concrete-lined power tunnel is assumed to extend from the vertical shaft to the penstock manifold. The power tunnel length for each concept was assumed to be equal to 50 percent of the horizontal distance from intake to discharge. For Concepts 3 and 4, the power tunnel length was assumed to be equal to 100 percent of the horizontal distance from intake to discharge because the surface powerstation on the lower reservoir would not have tailrace tunnels. Table 3-6 lists costs for the power tunnels for each of the options. The unit costs were derived from Figure 6-13 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 3-6. Power Tunnel Characteristics and Estimated Costs

Development	Option	No. of Tunnels	Length of Each Tunnel (ft)	Total Tunnel Length (ft)	Tunnel Diameter (ft)	1988 Est. Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs ($)
Yellowtail-Yellowtail Afterbay	5A	1	2,500	2,500	30	4,500	3	33,750,000
	5B	1	2,900	2,900	32	4,800	3	41,760,000
	4YA-1	1	1,996	1,996	15	1,500	3	8,981,280
	4YA-2	1	1,996	1,996	10	1,000	3	5,987,520
Pathfinder-Alcova	5A1	1	2,500	2,500	20	2,400	3	18,000,000
	5D	1	3,250	3,250	32	4,900	3	47,775,000
Seminoe-Kortes	5A1	1	2,600	2,600	15	1,500	3	11,700,000
	5A2	1	3,200	3,200	28	4,000	3	38,400,000
	5C	1	2,150	2,150	23	2,700	3	17,415,000
	5D1	1	1,750	1,750	14	1,100	3	5,775,000
Trinity-Lewiston	5A-B	1	3,590	3,590	32	4,900	3	52,778,880
	5F	1	7,650	7,650	15	1,750	3	40,162,500
	5G2-A	1	2,534	2,534	34	5,400	3	41,057,280
	4TL	1	3,849	3,849	16	1,700	3	19,630,512

3.4.6 Penstock

Upstream of the powerhouse, at a distance assumed to equal 10 percent of the horizontal distance from intake to discharge, the power tunnel would transition via a distribution manifold into individual unit penstocks. Table 3-7 lists the penstock characteristics and costs for each of the options. The unit costs were derived from Figure 6-15 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 3-7. Penstock Characteristics and Estimated Costs

Development	Option	No. of Penstocks	Length of Each Penstock (ft)	Total Length of Penstock	Dia. (ft)	Head (ft)	1988 Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs ($)
Yellowtail-Yellowtail Afterbay	5A	4	625	2,500	13	1,562	4,900	3	36,750,000
	5B	4	725	2,900	14	1,352	4,900	3	42,630,000
	4YA-1	2	222	444	11	444	2,400	3	3,193,344
	4YA-2	2	222	444	8	431	1,600	4	2,838,528
Pathfinder-Alcova	5A1	2	1,025	2,050	13	1,232	4,200	3	25,830,000
	5D	4	813	3,250	16	621	4,250	3	41,437,500
Seminoe-Kortes	5A1	2	650	1,300	10	1,025	2,400	3	9,360,000
	5A2	4	800	3,200	14	869	4,000	3	38,400,000
	5C	2	538	1,075	17	909	5,500	3	17,737,500
	5D1	2	438	875	9	1,126	2,000	3	5,250,000
Trinity-Lewiston	5A-B	3	898	2,693	19	635	6,500	3	52,509,600
	5F	2	1,913	3,825	9	2,248	3,000	3	34,425,000
	5G2-A	4	634	2,534	17	775	5,500	3	41,817,600
	4TL	2	428	855	12	401	2,800	3	7,185,024

3.4.7 Draft Tube Tunnels and Gates

Table 3-8 shows the draft tube detail for the Concept 5 options. Each draft tube length is assumed to be 10 percent of the horizontal distance from intake to discharge. The unit costs were derived from Figure 6-15 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 3-8. Draft Tube Characteristics and Estimated Costs

Development	Option	No. of Draft Tubes	Length of Each Draft Tube (ft)	Total Length of Draft Tube (ft)	Dia. (ft)	Head (ft)	1988 Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs($)
Yellowtail-Yellowtail Afterbay	5A	4	625	2,500	18	1,562	8,500	3	63,750,000
	5B	4	725	2,900	20	1,352	9,000	3	78,300,000
	4YA-1								-
	4YA-2								-
Pathfinder-Alcova	5A1	2	1,025	2,050	18	1,232	6,500	3	39,975,000
	5D	4	813	3,250	22	621	8,100	3	78,975,000
Seminoe-Kortes	5A1	2	650	1,300	13	1,025	3,500	3	13,650,000
	5A2	4	800	3,200	20	1869	7,600	3	72,960,000
	5C	2	538	1,075	23	909	9,800	3	31,605,000
	5D1	2	438	875	13	1,126	2,500	3	6,562,500
Trinity-Lewiston	5A-B	3	898	2,693	26	635	10,500	3	84,823,200
	5F	2	1,913	3,825	12	2,248	5,000	3	57,375,000
	5G2-A	4	634	2,534	24	775	10,000	3	76,032,000
	4TL								-

3.4.8 Draft Tube Gate/Transformer Gallery

The substation for the Concept 5 options would be located in an underground cavern located just downstream of the powerhouse within a common draft tube gate/transformer gallery. For Concepts 3 and 4 options, the substation would be on the surface adjacent to the powerhouse. For the four-unit options, this cavern was assumed to measure approximately 45 feet wide, 55 feet tall, and 500 feet long. According to recent quotes for similar structure, the cost of this installation would be approximately $26,000,000. For two-unit options, the cost would be $13,000,000.

3.4.9 Tailrace Tunnels

For the Concept 5 options, a concrete-lined tailrace tunnel was assumed for every two draft tube tunnels, extending to the lower reservoir discharge structure. The tailrace tunnel lengths were assumed to be equal to 50 percent of the horizontal distance from intake to discharge. Table 3-9 lists the costs for the tailrace tunnels for each Concept 5 option. The unit costs were derived from

Figure 6-13 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 3-9. Tailrace Tunnel Characteristics and Estimated Costs

Development	Option	No. of Tailrace Tunnels	Length of Each Tailrace Tunnel (ft)	Total Length of Tailrace Tunnel (ft)	Dia. (ft)	1988 Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs($)
Yellowtail-Yellowtail Afterbay	5A	2	2,500	5,000	25	3,200	3	48,000,000
	5B	2	2,900	5,800	26	3,400	3	59,160,000
	4YA-1							-
	4YA-2							-
Pathfinder-Alcova	5A1	1	8,000	8,000	23	2,900	3	69,600,000
	5D	2	3,250	6,500	26	3,400	3	66,300,000
Seminoe-Kortes	5A1	1	2,600	2,600	18	1,850	3	14,430,000
	5A2	2	3,200	6,400	23	2,750	3	52,800,000
	5C	1	2,150	2,150	27	3,500	3	22,575,000
	5D1	1	1,750	1,750	17	1,700	3	8,925,000
Trinity-Lewiston	5A-B	1	3,590	3,590	37	4,900	3	52,778,880
	5F	1	7,650	7,650	18	2,200	3	50,490,000
	5G2-A	2	2,534	5,069	28	4,000	3	60,825,600
	4TL							-

3.4.10 Lower Reservoir Discharge/Intake Structure and Channel

A discharge/intake structure and channel would need to be constructed for the Concept 5 options in the waters of the lower reservoir. Table 3-10 lists the costs for the lower reservoir discharge/intake for each Concept 5 option, which consists of a horizontal intake. The unit costs were derived from Figure 6-12 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 3-10. Lower Reservoir Intake Characteristics and Estimated Costs

Development	Option	No. of Tunnels	Dia. (ft)	1988 Unit Costs ($)	Index Factor	2012 Total Est. Costs($)
Yellowtail-Yellowtail Afterbay	5A	2	25	6,500,000	3	39,000,000
	5B	2	26	6,900,000	3	41,400,000
	4YA-1					-
	4YA-2					-
Pathfinder-Alcova	5A1	1	23	5,500,000	3	16,500,000
	5D	2	26	6,900,000	3	41,400,000
Seminoe-Kortes	5A1	1	18	3,500,000	3	10,500,000
	5A2	2	23	5,500,000	3	33,000,000
	5C	1	27	7,500,000	3	22,500,000
	5D1	1	17	3,200,000	3	9,600,000
Trinity-Lewiston	5A-B	1	37	16,000,000	3	48,000,000
	5F	1	18	3,500,000	3	10,500,000
	5G2-A	2	28	8,200,000	3	49,200,000
	4TL					-

3.4.11 Surge Chambers

In general, water conductors and associated appurtenances are economically designed to accommodate permissible head losses and tunnel velocities, possess sufficient ability to follow load changes, and offer protections to structural members from excess pressure in the event of sudden gate changes and/or load rejections. When the control, directed by the governor, causes undesirable pressure variations (generally 40 percent rise and 25 percent drop), a surge chamber is often used to dissipate transient pressures. A surge chamber is generally a tank, cavern, or shaft consisting of an atmospheric standpipe, attached to the headrace tunnel and/or penstock. This facility provides a reservoir and expansion chamber to accommodate water demand or water rejection following sudden gate movements to mitigate internal pressures and rapid accelerations or decelerations of the flow within the water conveyance system.

This analysis conservatively assumes that surge protection for the Concept 5 options would be required. Firm determination, sizing, and location(s) of the water conductors are beyond the scope of this study and therefore are not shown on the conceptual project sketches. According to page 6-22 in EPRI Document No. GS-6669 (1990), a Class 5 cost opinion for a surge chamber is approximately 30 percent of the cost to construct the water conveyance system.

3.4.12 Powerstation Equipment

Table 3-11 lists underground (Concept 5) and surface (Concepts 3 and 4) powerhouse equipment cost estimates complete with assumptions for each of the site options. The 1988 cost estimates provided in this table were obtained from Figures 6-17 through 6-18 of EPRI Document No. GS-6669 and include the items listed below assuming single-speed unit technology. These costs were then indexed to 2012 dollars using an escalation factor of 3.0.

Table 3-11. Power Equipment Costs

Development	Option	Design Head (ft)	Installed Capacity (MW)	No. Units	MW per Unit	1988 Unit Costs ($/kW)	Index Factor	2012 Total Est. Costs($)
Yellowtail-Yellowtail Afterbay	5A	1,562	1,660	4	415	105	3	522,930,353
	5B	1,352	1,607	4	402	104	3	501,280,740
	4YA-1	444	112	2	56	238	3	80,205,048
	4YA-2	431	54	2	27	245	3	39,390,314
Pathfinder-Alcova	5A1	1,232	575	2	287	135	3	232,687,059
	5D	621	708	4	177	140	3	297,454,814
Seminoe-Kortes	5A1	1,025	277	2	138	180	3	149,412,764
	5A2	869	773	4	193	132	3	306,265,855
	5C	909	572	2	286	137	3	234,902,364
	5D1	1,126	266	2	133	180	3	143,841,363
Trinity-Lewiston	5A-B	635	765	3	255	140	3	321,463,111
	5F	2,248	615	2	308	110	3	202,968,670
	5G2-A	775	1,024	4	256	133	3	408,774,027
	4TL	401	111	2	56	240	3	80,034,895

3.4.12.1 Major Equipment

Major equipment includes single-speed pump/turbines, governors, inlet valves, and generator/motors.

3.4.12.2 Accessory Electrical Equipment

Accessory electrical equipment includes main transformers, control and communications equipment, starting equipment, main leads, breakers, switches, and current limiting reactors.

3.4.12.3 Miscellaneous Mechanical Equipment

Miscellaneous mechanical equipment includes bridge crane, HVAC, cooling water, drainage, compressed air system, emergency diesel generator, and other smaller items.

3.4.13 Power Complex Access Tunnels

For Concept 5 options, access to each underground power complex was assumed to be via a main access tunnel and a high voltage/HVAC tunnel. Each tunnel was assumed to be a 25-foot-tall horseshoe-type installed on a slope of 10 percent. To account for unit submergence and upper machine hall elevation, each tunnel was assumed to measure approximately half of the horizontal distance from intake to discharge. Table 3-12 lists the costs for the power complex access tunnel for each Concept 5 option. The unit costs were derived from Figure 6-19 in EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an escalation factor of 3.0.

Table 3-12. Access Tunnel Characteristics and Estimated Costs

Development	Option	Access Tunnel Length (ft)	1988 Est. Unit Costs ($/ft)	Index Factor	2012 Total Est. Costs($)
Yellowtail-Yellowtail Afterbay	5A	3,125	2,370	3	22,218,750
	5B	3,625	2,420	3	26,317,500
	4YA-1				-
	4YA-2				-
Pathfinder-Alcova	5A1	8,000	2,500	3	60,000,000
	5D	4,063	2,440	3	29,737,500
Seminoe-Kortes	5A1	3,250	2,380	3	23,205,000
	5A2	4,000	2,440	3	29,280,000
	5C	2,688	2,320	3	18,705,000
	5D1	2,188	2,250	3	14,765,625
Trinity-Lewiston	5A-B	4,488	2,480	3	33,390,720
	5F	9,563	2,680	3	76,882,500
	5G2-A	3,168	2,370	3	22,524,480
	4TL				-

3.4.14 Underground Excavation Haul Tunnels

For the Concept 5 options, approximately 2,000 feet of tunnels would be required for the purpose of removing muck during construction of the underground power complex and water conveyance tunnels. The costs of these tunnels have been estimated to cost in the order of $5,000 per linear foot, for a total cost opinion of $12,000,000.

3.4.15 Transmission Line

For the purpose of this study, the following tie points (to obtain transmission line lengths) for the options are assumed:

- Yellowtail-Yellowtail Afterbay - The tie point is assumed to be at the switchyard located along the left abutment adjacent to the Yellowtail dam.
- Seminoe - The tie point is assumed to be at the Seminoe dam.

- Pathfinder – The tie point is assumed to be at the switchyard just downstream of the Alcova dam.
- Trinity – The tie point is assumed to be at the switchyard just downstream of the Trinity dam.

The unit costs provided in Table 3-13 were derived from Figure 6-21 of EPRI Document No. GS-6669 (1990) assuming 138 kV, 230 kV, 345 kV, or 500 kV and average construction conditions. No attempt was made to establish a firm transmission alignment; instead, an assumed route was utilized. The combined cost for land acquisition and clearing was estimated at $15,000 per acre, assuming a 200-foot right-of-way for each option. An index factor of 3.0 was assumed for this exercise.

Table 3-13. Transmission Line Characteristics and Estimated Costs

Development	Option	Assumed Length (Miles)	Assumed Voltage (kV)	Transmitted Power (MW)	1988 Est. Line Costs ($/mile)	Index Factor	2012 Total Est. Costs($)
Yellowtail-Yellowtail Afterbay	5A	10	500	1,660	430,000	3	12,900,000
	5B	8	500	1,607	430,000	3	10,320,000
	4YA-1	0.5	230	112	190,000	3	285,000
	4YA-2	0.5	138	54	125,000	3	187,500
Pathfinder-Alcova	5A1	20	345	575	290,000	3	17,400,000
	5D	8	345	708	290,000	3	6,960,000
Seminoe-Kortes	5A1	2	230	277	190,000	3	1,140,000
	5A2	2	345	773	310,000	3	1,860,000
	5C	2	345	572	290,000	3	1,740,000
	5D1	1.5	230	266	190,000	3	855,000
Trinity-Lewiston	5A-B	3	345	765	290,000	3	2,610,000
	5F	4	345	615	290,000	3	3,480,000
	5G2-A	12	500	1,024	430,000	3	15,480,000
	4TL	0.5	230	111	190,000	3	285,000

It should be noted that the cost to upgrade other substation and transmission line systems are not included in this report and could be substantial.

3.4.16 Switchyard

To estimate the switchyard cost, the project team assumed a conventional outdoor air-insulated substation with voltages consistent with that listed above for the new transmission lines. The 1988 cost estimates provided in Table 3-14 were obtained from Figure 6-20 of EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars assuming an index factor of 3.0.

Table 3-14. Switchyard Characteristics and Estimated Costs

Development	Option	Assumed Voltage (kV)	Installed Capacity (MW)	No. Units	1988 Unit Costs ($)	Index Factor	2012 Total Est. Costs($)
Yellowtail-Yellowtail Afterbay	5A	500	1,660	4	14,000,000	3	42,000,000
	5B	500	1,607	4	14,000,000	3	42,000,000
	4YA-1	230	112	2	1,700,000	3	5,100,000
	4YA-2	138	54	2	1,300,000	3	3,900,000
Pathfinder-Alcova	5A1	345	575	2	3,500,000	3	10,500,000
	5D	345	708	4	8,000,000	3	24,000,000
Seminoe-Kortes	5A1	230	277	2	1,700,000	3	5,100,000
	5A2	345	773	4	8,000,000	3	24,000,000
	5C	345	572	2	3,500,000	3	10,500,000
	5D1	230	266	2	1,700,000	3	5,100,000
Trinity-Lewiston	5A-B	345	765	3	3,500,000	3	10,500,000
	5F	345	615	2	3,500,000	3	10,500,000
	5G2-A	500	1,024	4	14,000,000	3	42,000,000
	4TL	230	111	2	1,700,000	3	5,100,000

3.4.17 Roads

Project access roads were assumed to be constructed at each of the primary project areas. New roads were assumed to extend from existing roads to major project elements. Assumed roadway lengths and costs are provided in Table 3-15, derived from Section 6 of EPRI Document No. GS-6669 (1990) and indexed to 2012 dollars using an index factor of 3.0.

1988 Cost for New Access Roads

Terrain	$/mile
Steep	439,000
Mild	283,000
Flat	189,000

Table 3-15. Assumed Roadway Lengths and Estimated Costs

Development	Option	Assumed Length of New Access Road (Miles)	Total 1988 Cost for New Access Roads ($)	Index Factor	2012 Total Est. Costs($)
Yellowtail-Yellowtail Afterbay	5A	5	1,867,000	3	5,600,000
	5B	5	1,867,000	3	5,600,000
	4YA-1				-
	4YA-2				-
Pathfinder-Alcova	5A1	5	1,867,000	3	5,600,000
	5D	5	1,867,000	3	5,600,000
Seminoe-Kortes	5A1	5	1,867,000	3	5,600,000
	5A2	5	1,867,000	3	5,600,000
	5C	10	3,700,000	3	11,100,000
	5D1	10	3,700,000	3	11,100,000
Trinity-Lewiston	5A-B	10	3,700,000	3	11,100,000
	5F	10	3,700,000	3	11,100,000
	5G2-A	10	3,700,000	3	11,100,000
	4TL				-

3.4.18 Lands

The cost opinion does not include any cost for the acquisition of lands.

3.4.19 Stream Augmentation – Minimum Flow System

Specific to utilizing Kortes Reservoir as a lower reservoir for pump-generation, stream augmentation will be required to pass a flow of 500 cfs, as needed, downstream of Kortes to meet current regulations. Currently, the required flow is passed downstream by either power generation or overflow spill at the Kortes Powerhouse spillway. No outlet works exist to provide the required flow, so the Kortes Reservoir is kept close to spill. In the event that the units are taken offline, the reservoir level rises overtopping the overflow spillway to ensure the required flow passes downstream.

To utilize the entire active reservoir at Kortes for pump-generation, installation of a minimum flow system to meet downstream flow regulations is required and included in the cost for each option using Kortes as a lower reservoir.

Chapter 4
Cost Opinions and Project Schedules

4.1 Direct Cost Estimate

A summary of the estimated direct cost (i.e., cost of materials, equipment, and labor for construction of structures, and supply and installation of permanent equipment) for each reservoir option is provided in Table 4-1. It should be noted that these costs only represent an AACE Class 5 cost opinion based on very conceptual layout information and derived from cost curves provided by EPRI's Pumped Storage Planning and Evaluation Guide, escalated to 2012 dollars (Appendix A).

4.2 Indirect Costs

Indirect costs generally run between 15 and 30 percent of direct costs, and are largely dependent on configuration, environmental/regulatory, and ownership complexities. An allowance of 25 percent has been allocated for indirect costs, including:

- Preliminary engineering and studies (planning studies, environmental impact studies, investigations);
- License and permit applications and processing;
- Detailed engineering and studies;
- Construction management, quality assurance, and administration; and
- Bonds, insurances, taxes, and corporate overheads

Table 4-2. Opinion of Probable Cost Summary

Site	Yellowtail-Yellowtail Afterbay	Yellowtail-Yellowtail Afterbay	Yellowtail-Yellowtail Afterbay	Yellowtail-Yellowtail Afterbay	Pathfinder - Alcova	Pathfinder - Alcova	Seminoe - Kortes	Seminoe - Kortes	Seminoe - Kortes	Seminoe - Kortes	Trinity - Lewiston	Trinity - Lewiston	Trinity - Lewiston	Trinity - Lewiston
Options	**5A**	**5B**	**4YA-1**	**4YA-2**	**5A1**	**5D**	**5A1**	**5A2**	**5C**	**5D1**	**5A-B**	**5F**	**5G2-A**	**4TL**
Approximate Installed Capacity (MW)	1,660	1,607	112	54	575	708	277	773	572	266	765	615	1,024	111
Assumed Number of Units	4	4	2	2	2	4	2	4	2	2	3	2	4	2
Assumed Static Head (ft)	1,562	1,352	444	431	1,232	621	1,025	869	909	1,126	635	2,248	775	401
Assumed Usable Storage Volume (acre-ft)	12,081	13,509	2,875	1,413	5,297	12,950	3,068	10,119	7,145	2,689	13,697	3,154	15,022	3,154
Energy Storage (MWH)	16,601	16,067	1,123	536	5,745	7,082	2,767	7,734	5,715	2,664	7,654	6,151	10,245	1,112
Hours of Storage	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Tunnel Diameter (ft)	1 @ 30 ft	1 @ 32 ft	1 @ 15 ft	1 @ 10 ft	1 @ 20 ft	1 @ 32 ft	1 @ 15 ft	1 @ 28 ft	1 @ 23 ft	1 @ 14 ft	1 @ 32 ft	1 @ 15 ft	1 @ 34 ft	1 @ 16 ft
Penstock Diameter (ft)	4 @ 13 ft	4 @ 14 ft	2 @ 11 ft	2 @ 8 ft	2 @ 13 ft	4 @ 16 ft	2 @ 10 ft	4 @ 14 ft	2 @ 17 ft	2 @ 9 ft	3 @ 19 ft	2 @ 9 ft	4 @ 17 ft	2 @ 12 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
Upper Reservoir and Dams														
Dam	$176,342,336	$149,156,365			$85,920,962	$132,055,077	$108,302,710	$219,525,143	$190,941,629	$47,006,141	$178,689,391	$69,987,809	$93,595,991	
Stream Diversion	$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	
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	
Civil Works														
Power Station - Civil	$149,408,672	$183,160,270	$28,981,656	$15,273,795	$86,180,392	$140,228,698	$56,444,822	$134,571,361	$99,447,716	$53,540,952	$172,212,381	$68,271,280	$165,968,402	$28,679,171
Upper Reservoir Intake	$6,300,000	$6,900,000	$7,500,000	$4,200,000	$2,250,000	$6,900,000	$1,350,000	$5,700,000	$3,000,000	$900,000	$6,900,000	$1,350,000	$9,600,000	$8,250,000
Vertical Shaft	$26,701,650	$24,327,000	$3,729,600	$2,586,000	$13,680,195	$11,186,100	$8,610,000	$14,069,700	$11,452,770	$8,778,900	$11,430,000	$18,883,200	$15,112,500	$3,604,500
Horizontal Power Tunnel	$33,750,000	$41,760,000	$8,981,280	$5,987,520	$18,000,000	$47,775,000	$11,700,000	$38,400,000	$17,415,000	$5,775,000	$52,778,880	$40,162,500	$41,057,280	$19,630,512
Penstocks	$36,750,000	$42,630,000	$3,193,344	$2,838,528	$25,830,000	$41,437,500	$25,830,000	$38,400,000	$17,737,500	$5,250,000	$52,509,600	$34,425,000	$41,817,600	$7,185,024
Draft Tube Tunnels & DT Gates	$63,750,000	$78,300,000	$-	$-	$39,975,000	$78,975,000	$13,650,000	$72,960,000	$31,605,000	$6,562,500	$84,823,200	$57,375,000	$76,032,000	$-
Tailrace Tunnels	$48,000,000	$59,160,000	$-	$-	$69,600,000	$66,300,000	$14,430,000	$57,600,000	$22,575,000	$8,925,000	$52,778,880	$50,490,000	$60,825,600	$-
Discharge Structure & Channel	$39,000,000	$41,400,000	$-	$-	$16,500,000	$41,400,000	$10,500,000	$33,000,000	$22,500,000	$9,600,000	$48,000,000	$10,500,000	$49,200,000	$-
Surge Chamber	$62,685,495	$73,853,100	$-	$-	$50,1255,559	$73,702,080	$22,266,000	$66,428,910	$30,235,581	$10,587,420	$76,296,168	$60,400,710	$70,453,494	$-
Draft Tube / Transformer Gallery	$26,000,000	$26,000,000	$-	$-	$13,000,000	$26,000,000	$13,000,000	$26,000,000	$13,000,000	$13,000,000	$19,500,000	$13,000,000	$26,000,000	$-
Access Tunnels	$22,218,750	$26,317,500	$-	$-	$60,000,000	$29,737,500	$23,205,000	$29,280,000	$18,705,000	$14,765,625	$33,390,720	$76,882,500	$22,524,480	$-
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	$-

Table 4-2. Opinion of Probable Cost Summary

Site	Yellowtail-Yellowtail Afterbay	Yellowtail-Yellowtail Afterbay	Yellowtail-Yellowtail Afterbay	Yellowtail-Yellowtail Afterbay	Pathfinder - Alcova	Pathfinder - Alcova	Seminoe - Kortes	Seminoe - Kortes	Seminoe - Kortes	Seminoe - Kortes	Trinity - Lewiston	Trinity - Lewiston	Trinity - Lewiston	Trinity - Lewiston
Options	**5A**	**5B**	**4YA-1**	**4YA-2**	**5A1**	**5D**	**5A1**	**5A2**	**5C**	**5D1**	**5A-B**	**5F**	**5G2-A**	**4TL**
Site Roads	$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	$-
Miscellaneous civil works and structures	$25,000,000	$25,000,000	$10,000,000	$10,000,000	$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	$10,000,000
Power Plant Equipment	$522,930,353	$501,280,740	$80,205,048	$39,390,314	$232,687,059	$297,454,814	$149,412,764	$306,265,855	$234,902,364	$143,841,363	$321,463,111	$202,968,670	$408,774,027	$80,034,895
Switchyard	$42,000,000	$42,000,000	$5,100,000	$3,900,000	$10,500,000	$24,000,000	$5,100,000	$24,000,000	$10,500,000	$5,100,000	$10,500,000	$10,500,000	$42,000,000	$5,100,000
Stream Augmentation - Min Flow System							$28,798,869			$28,798,869				
Transmission	$12,900,000	$10,320,000	$285,000	$187,500	$17,400,000	$6,960,000	$1,140,000	$1,860,000	$1,740,000	$855,000	$2,610,000	$3,480,000	$15,480,000	$285,000
Subtotal	$1,321,337,256	$1,359,164,975	$147,975,928	$84,363,657	$749,249,168	$1,076,711,769	$546,340,165	$1,120,660,969	$783,857,560	$421,386,770	$1,181,982,331	$776,776,669	$1,196,541,373	$162,769,101
Temporary Facilities & Site Prep	$66,066,863	$67,958,249	$7,398,796	$4,218,183	$39,712,458	$53,835,588	$27,317,008	$56,033,048	$39,192,878	$21,069,338	$59,099,117	$38,838,833	$59,827,069	$8,138,455
Subtotal Direct Costs	$1,387,404,119	$1,427,123,224	$155,374,724	$88,581,840	$833,961,626	$1,130,547,358	$573,657,173	$1,176,694,017	$823,050,438	$442,456,108	$1,241,081,448	$815,615,503	$1,256,368,442	$170,907,556
Contingency (25%)	$346,851,030	$356,780,806	$38,843,681	$22,145,460	$208,490,407	$282,636,839	$143,414,293	$294,173,504	$205,762,609	$110,614,027	$310,270,362	$203,903,876	$314,092,110	$42,726,889
Indirect Costs (25%)	$346,851,030	$356,780,806	$38,843,681	$22,145,460	$208,490,407	$282,636,839	$143,414,293	$294,173,504	$205,762,609	$110,614,027	$310,270,362	$203,903,876	$314,092,110	$42,726,889
Total Construction Costs [(2) (3)]	$2,081,106,179	$2,140,684,836	$233,062,087	$132,872,760	$1,250,942,439	$1,695,821,037	$860,485,759	$1,765,041,025	$1,234,575,657	$663,684,162	$1,861,622,172	$1,223,423,254	$1,884,552,663	$256,361,335
Estimated Cost ($/MW)	$1,253,606	$1,332,374	$2,074,761	$2,479,327	$2,177,309	$2,394,464	$3,109,924	$2,282,188	$2,160,091	$2,491,560	$2,432,258	$1,989,123	$1,839,492	$2,306,246
Cost Ranking $/MW	1	2	5	12	7	10	14	8	6	13	11	4	3	9

Notes:

1. Costs not included at this level of analysis.
2. Cost estimates are AACE Class 5 estimates with 25 percent contingency.
3. Cost estimates are in 2012 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.

4.3 Life Cycle Costs

4.3.1 Annual Routine Operations and Maintenance Costs

EPRI provides the following equation for estimating the annual operations and maintenance (O&M) costs for a pump-generation project in 1985 dollars:

$$\text{O\&M Costs (\$/yr)} = 34{,}730 \times C^{0.32} \times E^{0.33}$$

Where: C = Plant Capacity (MW)
E = Annual Energy (GWh)

Table 4-2 represents annual O&M costs assuming 6 hours of operation per day for 365 days per year. Assuming an average annual inflation rate of 3 percent, the EPRI annual O&M cost relationship escalates by a factor of 2.5.

Table 4-2. Estimated O&M Costs

Development	Option	Installed Capacity (MW)	Annual Energy (GWh)	1985 O&M Costs ($)	Index Factor	2012 Annual O&M Costs($)
Yellowtail-Yellowtail Afterbay	5A	1,660	3,636	5,600,000	2.5	14,000,000
	5B	1,607	3,519	5,500,000	2.5	13,750,000
	4YA-1	112	246	1,000,000	2.5	2,500,000
	4YA-2	54	117	600,000	2.5	1,500,000
Pathfinder-Alcova	5A1	575	1,258	2,800,000	2.5	7,000,000
	5D	708	1,551	3,200,000	2.5	8,000,000
Seminoe-Kortes	5A1	277	606	1,700,000	2.5	4,250,000
	5A2	773	1694	3,400,000	2.5	8,500,000
	5C	572	1,252	2,800,000	2.5	7,000,000
	5D1	266	583	1,700,000	2.5	4,250,000
Trinity-Lewiston	5A-B	765	1,676	3,400,000	2.5	8,500,000
	5F	615	1,347	2,900,000	2.5	7,250,000
	5G2-A	1,024	2,244	4,100,000	2.5	10,250,000
	4TL	111	243	1,000,000	2.5	2,500,000

The project team performed a comparative assessment of the O&M costs for a similar pump-generation installation (underground, single speed technology) and finds these O&M costs to be reasonable. These expenses include annual FERC fees, labor, contracts, consumables, inventory, and other routine operation and maintenance activities. O&M costs do not incorporate pump power costs.

4.3.2 Bi-Annual Outage Costs

Units should be taken out of service for approximately 3 weeks every 2 years for routine bi-annual inspection and maintenance at a cost of approximately $150,000 (per unit).

4.3.3 Major Maintenance

Approximately $1,500,000 (per unit) should be budgeted for a major unit overhaul around year 20. A unit would be out of service for approximately 6 to 8 months, and the outages occur once per year.

4.4 Cost Comparison Data

The Class 5 cost opinions for each alternative are provided in Table 4-1. As a basis of comparison, EPRI sponsored a study, Quantifying the Value of Hydropower in the Electric Grid: Final Report (2013), in which cost data for 34 pumped storage projects at various stages of development and configuration were escalated to 2010 dollars (EPRI 2013). The study can be found at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001023144

Table 4-3 is from the report (Table 2-2 in EPRI 2013) and shows construction cost data from pumped storage projects constructed and in various stages of development in the United States. The 2010 cost of most projects evaluated within this study ranged from $500 to $2,500 per kW. New large scale pumped storage projects were estimated to cost between $1,000 and $2,500 per kW. Upgrades to existing facilities were significantly less (EPRI 2013).

Table 4-3 Pumped Storage Construction Cost Data (EPRI 2013)

Project	Single vs. Variable Speed	Stated Capacity (MW)	Est. Cost ($/kW)	Year of Cost	Escalation Factor to 2010	Est. Cost 2010 ($/kW)	Max. Gross Head (ft)	Ratio ($/kW/Head)
Projects Constructed in U.S. 1960–1988 (Do not include AFUDC or transmission interconnection costs)								
Taum Sauk	SS	350	462	1988	2.6	1,201	267	4.5
Yards Creek	SS	330	332	1988	2.6	863	760	1.14
Muddy Run	SS	855	322	1988	2.6	837	127	6.62
Cabin Creek	SS	280	404	1988	2.6	1,050	373	2.81
Seneca	SS	380	505	1988	2.6	1,313	165	7.96
Northfield	SS	1,000	288	1988	2.6	749	252	2.97
Blenheim-Gilboa	SS	1,030	321	1988	2.6	835	1,143	0.73
Ludington	SS	1,890	376	1988	2.6	978	364	2.69
Jocassee	SS	628	422	1988	2.6	1,097	335	3.28
Bear Swamp	SS	540	507	1988	2.6	1,318	235	5.62
Raccoon Mtn.	SS	1,530	296	1988	2.6	770	1,042	0.74
Fairfield	SS	512	586	1988	2.6	1,524	169	9.02
Helms	SS	1,050	616	1988	2.6	1,602	1,745	0.92
Bath County	SS	2,100	639	1988	2.6	1,661	1,260	1.32
U.S. Projects Various Stage of Study Development Not Constructed								
Eagle Mtn.	SS & VS	1,300	1,062	2010	1	1,062	1,572	0.68
Mokelumne	SS	1,200	2,342	2009	1.05	2,342	1,863	1.26
Red Mtn Bar	SS	900	1,851	2008	1.1	1,999	830	2.41
Mulqueeney Ranch	SS	280	1,500	2009	1.05	1,500	700	2.14
Iowa Hill	VS	400	2,000	2010	1	2,000	1,223	1.64
Red Mtn Bar	VS	1,000	2,103	2008	1.1	2,342	830	2.82

4.5 Project Schedule

The project schedule will be dependent on many factors such as technology, site characteristics and subsurface conditions, as well as environmental and regulatory complications. However, the following development schedule could be reasonably assumed:

Phase	**Schedule**
Engineering studies, site characterization, and permits	2+ years
Detailed engineering and construction planning	2+ years
Construction and startup testing	5 years

Chapter 5
Operations, Regulatory and Environmental Screening and Economic Evaluation

This chapter presents the operations, regulatory, and environmental screening methods and results and the economic evaluation for the remaining pump generation options. The chapter begins with a description of key operations and environmental data for each site used to support the screening analysis.

5.1 Site Operations and Environmental Data

This section describes relevant project information for each site used to evaluate potential effects for the screening evaluation.

5.1.1 Bighorn Lake and Yellowtail Afterbay

Bighorn Lake, Yellowtail Dam and Yellowtail Afterbay are part of Reclamation's Yellowtail Unit of the Pick-Sloan Missouri Basin Program in south-central Montana. Bighorn Lake is about 72 miles long at maximum water surface elevation, 66 miles long at the top of joint-use storage, and extends into the Bighorn basin of Wyoming. The reservoir is confined in the canyon for most of its length. The reservoir uses include fish, wildlife, recreation, irrigation, power, municipal, and industrial. Bighorn Lake has a total capacity of 1,381,189 acre-feet at an elevation of 3,660 feet. However, excessive deposition of sediments in the lake has reduced the net capacity to 1,331,725 acre-feet (approximately 3.5% reduction) (Reclamation 2012a). Table 5-1 shows reservoir characteristics for Bighorn Lake.

Table 5-1. Bighorn Lake Reservoir Characteristics

Reservoir Allocations	Elevation (feet)	Storage Volume of Pool (AF)	Cumulative Reservoir Volume (AF)
Dam Crest	3660.0		
Maximum water surface elevation	3660.0		1,331,725
Top of Flood Elevation	3657.0		1,278,896
Top of Joint Use Elevation	3640.0	232,365	1,020,573
Top of Active Conservation Pool	3614.0	318,298	788,208
Top of Inactive Conservation	3547.0	452,186	469,910
Top of Dead Pool	3296.50	17,724	17,724
Streambed Elevation	3166.0		

Source: Reclamation 2012a

The inactive conservation and dead pools, below elevation 3,547 feet, are necessary to maintain a minimum lake level to allow for the operation of the hydroelectric power turbines. Below elevation 3,547 feet the power turbines must be shut off. The active conservation pool, between elevation 3,547 feet and 3,614 feet, is the storage space available for use in meeting all of the water supply needs served by the Yellowtail Unit. The joint use pool is used jointly in meeting water supply needs and to provide sufficient storage space for regulating high spring snowmelt runoff for flood control purposes. Three entities hold entitlements to stored water in Bighorn Lake; the Crow Tribe has a right to 300,000 acre-feet, the Northern Cheyenne Tribe has a right to 30,000 acre-feet and Pennsylvania Power and Light of Montana currently have a contract for 6,000 acre-feet (Reclamation 2012a).

Drought conditions from 2000 to 2007 resulted in low lake levels in Bighorn Lake and low flows in Bighorn River. Since then, stakeholders expressed concerns over existing operations and formed the Bighorn River System Issues Group that consists of federal, state, local, and tribal entities. The Issues Group has made recommendations on how operation could improve environmental resources, including fisheries in Bighorn River (Reclamation 2012a).

- Reservoir recreation and fishing: Anglers have requested higher lake levels, especially during the summer season. The NPS has requested the lake be maintained above elevation 3,630 feet during the summer recreation season and above elevation 3,620 feet during the rest of the year. The Wyoming Game and Fish (WYGF) made similar recommendations of higher lake levels to adequately produce the food supply needed to support the sport fishery (Reclamation 2012a).
- River fisheries: Montana Fish, Wildlife and Parks (MTFWP) says that the river flow below the Afterbay Dam needs to be at or above 2,500 cfs to provide good spawning, rearing and cover conditions in all major side channels along the river. If water supply conditions allow, the MTFWP would prefer flows near 3,500 cfs. When water supply conditions are not adequate to provide a minimum flow of 2,500 cfs then the next lower recommended flow is 2,000 cfs. The MTFWP's also recommended an absolute minimum flow of 1,500 cfs (Reclamation 2012a).
- River Erosion: To reduce bank erosion, stakeholders requested that river flow be held at or below 8,000 cfs when possible and flow releases be reduced gradually over a longer period of time than in the past (Reclamation 2012a).
- Flood Control: Flood control interests expressed the need to have the lake lowered a sufficient amount in the spring to effectively manage high spring snowmelt and rain induced flood flows. Input from interests along the river indicated that a flow above 10,000 cfs results in some overbank flow and minor flooding (Reclamation 2012a).

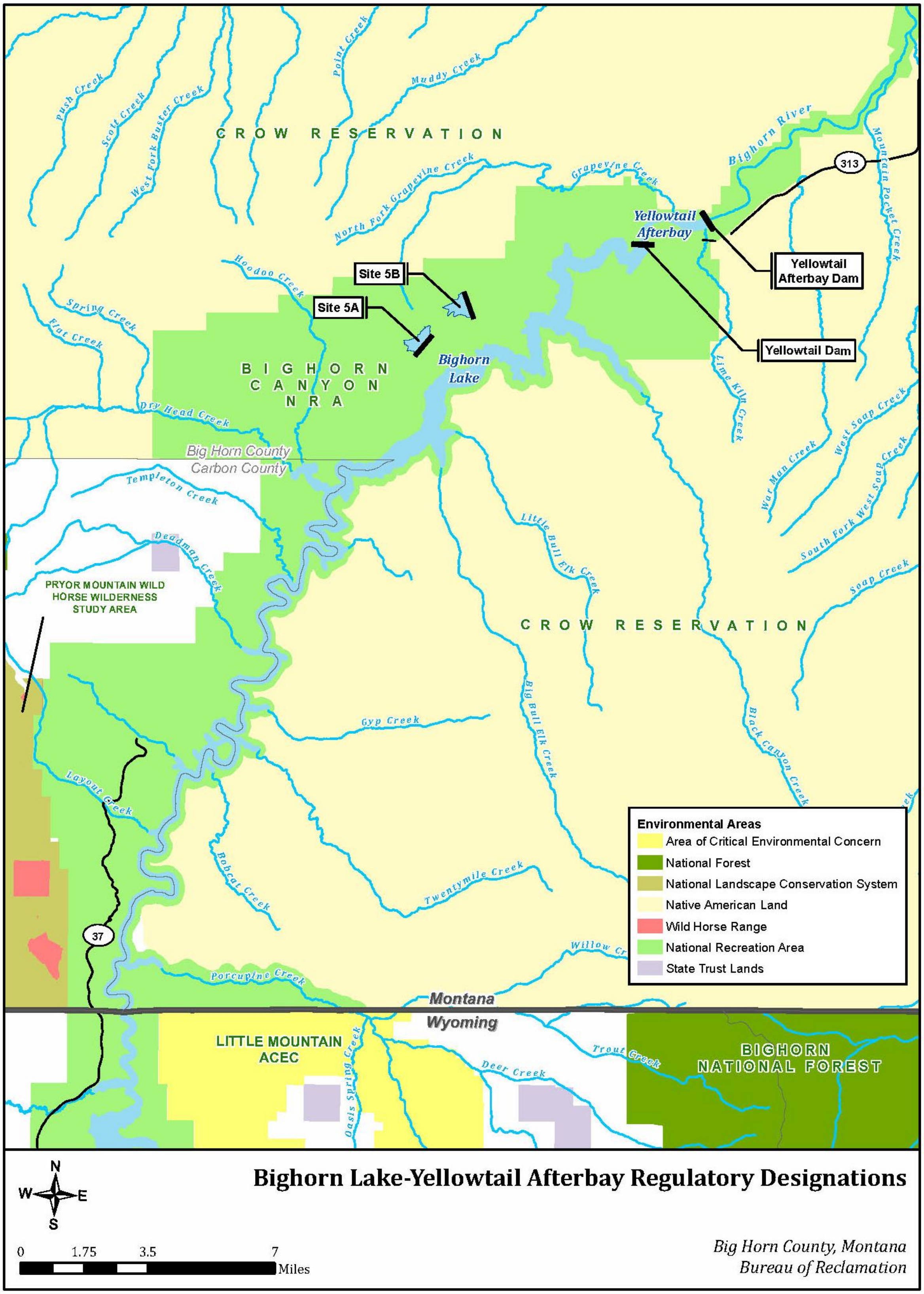
- Power Generation: Western Area Power Administration interests are in the gross power generated by the Yellowtail Unit, the timing of this generation such that it best fits with periods of high power demand, and the ability of the powerplant to regulate power over the course of each day to meet the diurnal fluctuating power demands. WAPA is also concerned with the reserve capacity of the powerplant that can be called on instantaneously (spinning reserves) or on short notice in response to electrical system emergencies (Reclamation 2012a).

Reclamation revised the 2012 operations of Bighorn Lake in response to the Issues Group concerns and recommendations. Target minimum flows during low flow periods are 1,500 cfs. The new operations criteria allow the reservoir to operate 2-3 feet higher on average than historic operations. The most significant change in lake elevations will be during late winter and early spring when the lake would operate 3-4 feet higher on the average. Revised operations benefit the trout fishery by an increased percent of time the fishery flow targets are met, an increase in river flow during the spring and early summer when the Rainbow trout spawn, and a more reliable overall water supply through periods of drought. With the higher lake levels provided by the revised criteria, the risk of reducing the river flow in the spring and especially below 1,500 cfs would be reduced (Reclamation 2012a).

Yellowtail Afterbay is used to level the peaking power discharges from Yellowtail Powerplant, which is at the base of Yellowtail Dam. Releases from Yellowtail Afterbay must meet minimum flow requirements in the Bighorn River that are defined by annual operating criteria for Bighorn Lake. Yellowtail Afterbay has a capacity of 3,141 acre-feet at an elevation of 3,192 feet. Reclamation operates Yellowtail Afterbay within a minimum elevation of 3,183 feet to a maximum elevation of 3,192 feet, a 9 foot operating range.

Figure 5-1 shows regulatory designations associated with Bighorn Lake and Yellowtail Afterbay. The reservoirs are encompassed in the Bighorn Canyon National Recreation Area (NRA), which is managed by the National Park Service (NPS). The NRA supports a variety of outdoor recreational opportunities such as boating, fishing, hiking, wildlife watching, camping, and biking. Bighorn Lake supports numerous fish species, including a restored walleye population. Bighorn River, downstream of Yellowtail Afterbay Dam, is Montana's most fished river and supports a world-class trout fishery. The endangered Black-footed ferret under the federal ESA has been known to occur in Big Horn County in Montana. The Crow Reservation surrounds the Bighorn Canyon NRA and has some tribal holding within the NRA. The Crow Tribe Water Rights Settlement Act, signed into law in 2010, secures 300,000 acre-feet from storage in Bighorn Lake, 500,000 acre-feet in natural flow of the Bighorn River, and the entire natural flow, groundwater, and storage in all other waterways on the Crow Reservation.

Figure 5-1. Bighorn Lake-Yellowtail Afterbay Regulatory Designations



5.1.2 Pathfinder and Alcova Reservoir

Pathfinder Reservoir is part of Reclamation's North Platte Project and Alcova Reservoir is part of the Kendrick Project. The North Platte Project extends 111 miles along the North Platte River Valley from Guernsey, Wyoming to Bridgeport, Nebraska. The Kendrick Project serves irrigable land on the northwest side of the North Platte River between Alcova and Casper, Wyoming. The North Platte River waters are stored and used for irrigation and power development for the North Platte Project, the Kendrick Project, and the Kortes and Glendo Units of the Pick-Sloan Missouri Basin Program.

Pathfinder Reservoir is a major storage facility of the North Platte Project. The reservoir purposes include power, wildlife, fish, irrigation, recreation, and flood control. Pathfinder Reservoir has a total capacity of 1,205,000 acre-feet at elevation 5,858.1 feet. The active conservation pool is 1,038,595 acre-feet. Operationally, this structure is a bottleneck in the system with its restricted release capability of approximately 6,000 cfs (Reclamation 2012b). Table 5-2 shows Pathfinder Reservoir characteristics.

Table 5-2. Pathfinder Reservoir Characteristics

Reservoir Allocations	Elevation (feet)	Storage Volume of Pool (AF)	Cumulative Reservoir Volume (AF)
Dam Crest /Maximum water surface elevation	5858.1		1,205,000
Top of Active Conservation Pool	5852.49	1,038,595	1,070,000
Top of Inactive Conservation	5746.0	31,398	31,405
Top of Dead	5693.2	7	7
Streambed Elevation	5658		

Source: Reclamation 2012c

Pathfinder Reservoir outlet works/canals are as follows:

- The uncontrolled spillway spills anytime the reservoir water surface exceeds 5,852.49 feet. The calculated discharge capacity of the spillway is 38,000 cfs at reservoir elevation 5,858.10 feet.
- The Freemont Canyon Power Tunnel is at an elevation of 5,715 feet.
- The North Outlet is at an elevation of 5,693.2 (Reclamation 2012c).

Alcova Reservoir is about 10 miles downstream from Pathfinder Dam. The reservoir purposes are fish, power, irrigation, and recreation. Alcova Reservoir storage capacity is about 184,405 acre-feet at elevation 5,500 feet, of which only the top 30,600 acre-feet is active capacity available for irrigation of the Kendrick Project. Table 5-3 shows Alcova Reservoir characteristics.

Table 5-3. Alcova Reservoir Characteristics

Reservoir Allocations	Elevation (feet)	Storage Volume of Pool (AF)	Cumulative Reservoir Volume (AF)
Dam Crest	5510.0		
Maximum water surface elevation/Active Conservation Pool	5500.0	30,603	184,405
Top of Inactive Conservation	5487.0	153,711	153,802
Top of Dead	5334.08	91	91
Streambed Elevation	5325.0		

Source: Reclamation 2012d

Alcova Reservoir outlet works/canals are as follows:

- The rated capacity of the left abutment outlet is 2,950 cfs at elevation 5498.0 feet.
- The spillway is a concrete lined open channel in the left abutment of the dam controlled by three 25 by 40 foot gates with a capacity of 55,000 cfs at a reservoir level of 5,500 feet.
- The Casper Canal is at an elevation of 5,487.0 feet.
- The penstock outlet is at the top of the dead zone at an elevation of 5,334.08 feet (Reclamation 2012d).

Alcova Reservoir operating requirements include:

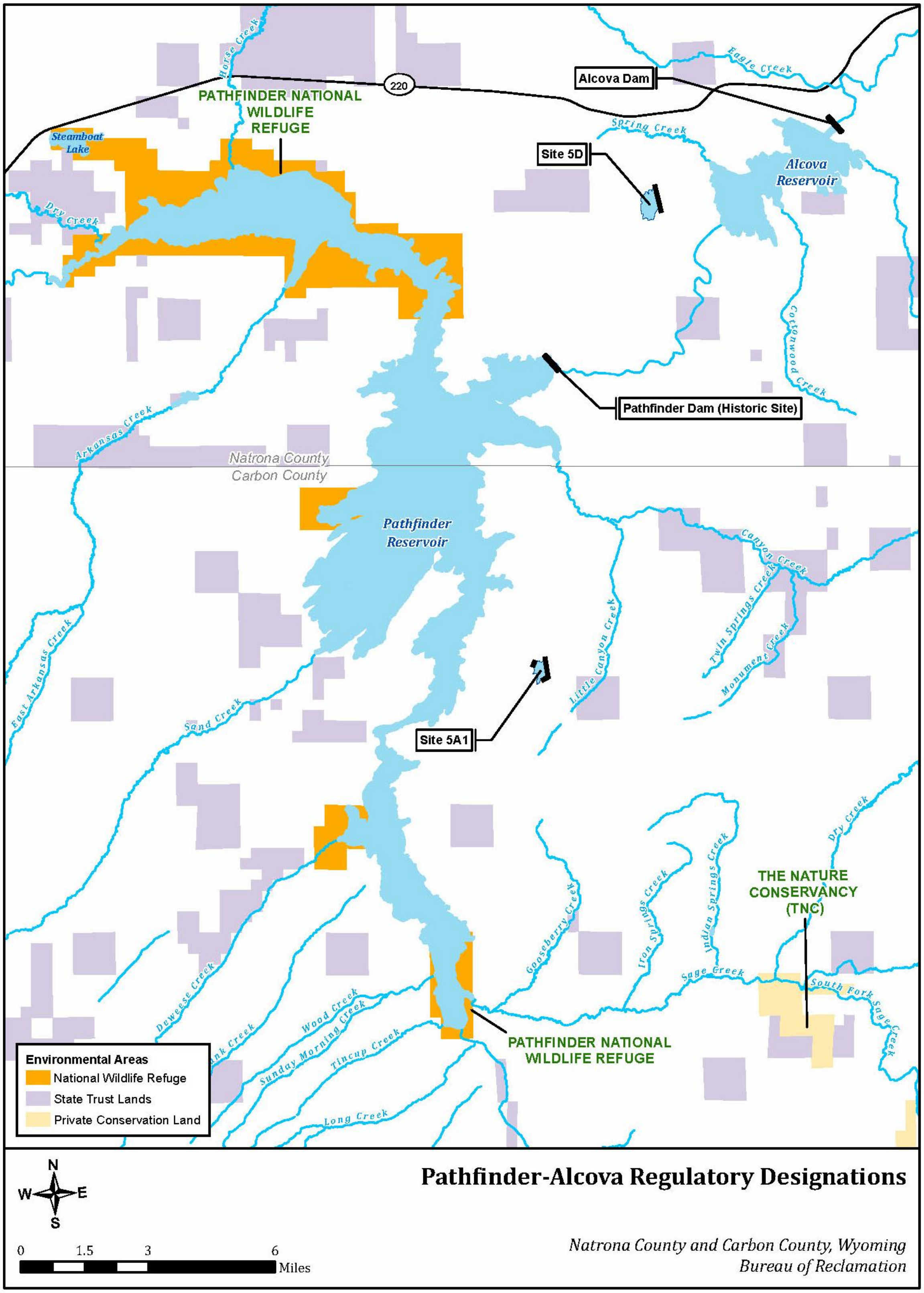
- The summer operating range is 5,498 feet plus/minus 1 foot to provide adequate head on the Casper Canal and accommodate recreation use.
- The winter operating range is at 5,488 feet plus/minus 1 foot to helps reduce the potential for ice damage to the canal gate and boat docks. Winter operations are from October to April (Reclamation 2012b).

Figure 5-2 shows regulatory designations associated with Pathfinder and Alcova Reservoirs. Pathfinder Dam, one of the first dams built under the 1902 Reclamation Act, was listed on the National Register of Historic Places in 1971. The dam also is listed as a Wyoming Historic Civil Engineering Landmark.

The Pathfinder National Wildlife Refuge consists of four units totaling 16,807 acres and is an important waterfowl migration stopover on the western edge of the Central Flyway. The largest unit surrounds the northwest portion of the reservoir.

Pathfinder and Alcova reservoirs are used for boating, fishing, camping, waterskiing, picnicking, and swimming. Natrona County is Reclamation’s managing partner for recreation activities at the reservoirs. Natrona County and Reclamation recently completed the Alcova- Gray Reef-Pathfinder Reservoirs

Figure 5-2. Pathfinder-Alcova Regulatory Designations



Resource Management Plan and Environmental Assessment in July 2012, which provides an updated planning document to manage and protect the reservoirs resources, including recreation and environmental habitat (Reclamation 2012e).

Game fish species found in both reservoirs include brown trout, cutthroat trout, rainbow trout, and walleye. Rainbow and cutthroat trout are stocked annually in the reservoirs. Fish populations in Pathfinder Reservoir decline during low inflow years, when the reservoir is drawn down to meet irrigation needs. Primary causes for decline include increased crowding, increased water temperatures, and decreased productivity. All inflows to Alcova Reservoir are controlled from upstream reservoirs. Water passing through Alcova Reservoir causes the reservoir to be flushed multiple times a year, which can affect food sources for fish species. During drought years, increased water temperatures can affect cold water species by drawing them to lower depths and into the penstock tunnel (Reclamation 2012e).

United States Fish and Wildlife Service (USFWS) identified three federally listed threatened or endangered species that may be present in the reservoirs' vicinity: Black-footed ferret, which resides in prairie dog towns; blowout penstemon, a perennial herb; and Ute ladies'-tresses, a perennial, terrestrial orchid. The greater sage-grouse, which is dependent on year-round sagebrush habitat, is a candidate species for listing (Reclamation 2012e).

5.1.3 Seminoe and Kortes Reservoirs

Seminoe Reservoir is part of the Kendrick Project and Kortes Reservoir is part of the Kortes Unit of the Pick-Sloan Missouri Basin Program. Facilities of the North Platte Project, the Kortes Unit of the Pick-Sloan Missouri Basin Program, and the Kendrick Project are interspersed along the North Platte River and operate together in the control of the river waters.

Seminoe Reservoir has a storage capacity of 1,017,273 acre-feet at an elevation of 6357.0 feet. Table 5-4 lists Seminoe Reservoir characteristics relative to operations and allocations.

Table 5-4. Seminoe Reservoir Characteristics

Reservoir Allocations	Elevation (feet)	Storage Volume of Pool (AF)	Cumulative Reservoir Volume (AF)
Dam Crest	6361.0		
Maximum water surface elevation/ Top of Active Conservation Pool	6357.0	985,603	1,017,273
Top of Inactive Conservation	6239.0	31,114	31,670
Top of Dead	6185.0	556	556
Streambed Elevation	6151.0		

Source: Reclamation 2012f

Seminoe Reservoir outlet works/canals are as follows:

- The spillway consists of a concrete-lined tunnel through the right abutment controlled by three fixed-wheel gates with a release capability of close to 48,500 cfs at 6,357 feet.
- Two 60 inch jet flow valves provide a low level river outlet with a flow capacity of 3,000 cfs at 6,357 feet.
- The outlet elevation is at 6,190 feet and the penstock outlet is at 6185.09 feet (Reclamation 2012f).

Kortes Reservoir is the afterbay for the Seminoe Reservoir and is about 2 miles below Seminoe Dam. The reservoir is primarily used for hydropower and fish uses. Kortes Reservoir provides a maximum storage capacity of 4,739 acre-feet at elevation 6165.7 feet. Water released from Seminoe Dam to Pathfinder Reservoir passes through the Kortes turbines to generate power. Table 5-5 lists operational characteristics of Kortes Reservoir.

Table 5-5. Kortes Reservoir Characteristics

Reservoir Allocations	Elevation (feet)	Storage Volume of Pool (AF)	Cumulative Reservoir Volume (AF)
Dam Crest	6169.0		
Maximum water surface elevation	6165.7		
Top of Active Conservation Pool	6142.0	3,073	4,739
Top of Inactive Conservation	6092.0	1,515	1,666
Top of Dead	6035.5	151	151
Streambed Elevation	5942.0		

Source: Reclamation 2012g

Kortes reservoir outlet works/canals are as follows:

- The spillway on the right abutment consists of an uncontrolled crest with a concrete-lined tunnel and has a capacity of 50,000 cfs at an elevation of 6,142 feet.
- The Penstock outlet is at an elevation of 6,035.5 feet (Reclamation 2012g).

Senate Bill 2553 which was passed in the 90th Congress authorized the modification of the operation of Kortes Dam and Powerplant to provide a minimum streamflow of 500 cfs in the North Platte River between Kortes Reservoir and the normal headwaters of Pathfinder Reservoir. The minimum flow permits maintenance of a fishery in a stretch of the North Platte River commonly referred to as the "Miracle Mile". Reclamation must operate Kortes Reservoir near maximum elevation in the event that the powerplant is offline and minimum releases must be made at the spillway. State of Wyoming has classified "The Miracle Mile" as Class 1 water body, where no additional water quality degradation will be allowed. Kortes and Seminoe reservoirs are classified Class 2AB water body supporting both drinking water and game fish (Bureau of Land Management Standard 5).

Figure 5-3 shows regulatory designations associated with Seminoe and Kortes reservoirs. Seminoe Reservoir is part of Seminoe State Park, which is managed for recreation by Wyoming State Parks, Historic Sites, and Trails. Seminoe Reservoir offers a full range of water-based activities and is known for both trout and walleye fishing. The reservoir is stocked annually with rainbow and cutthroat trout. Seminoe State Park has 3 campgrounds and 3 boat ramps.

The Morgan Creek Wildlife Habitat Management Area is adjacent to Seminoe Dam, near the northwest end of the reservoir. Through a cooperative agreement with the Reclamation, the WYGF manages the 4,125 acre wildlife area that was originally obtained for bighorn sheep but now supports a variety of wildlife, including elk. Big-game hunting is allowed in the area. The Bennett Mountain Wilderness Area is near the northeast shores of Seminoe Reservoir. The Bureau of Land Management manages the 6,003-acre area, which offers hunting, hiking, trapping, camping, wildlife viewing and sightseeing activities. This Wilderness Study Area was not recommended for wilderness status in the 1992 report to Congress (Bureau of Land Management 2011).

Kortes Reservoir is in a narrow canyon below Seminoe Dam. There is no recreation in Kortes Reservoir. Downstream of Kortes Reservoir, the Miracle Mile Area is a premier fishery for rainbow and brown trout. Camping is also available along the Miracle Mile.

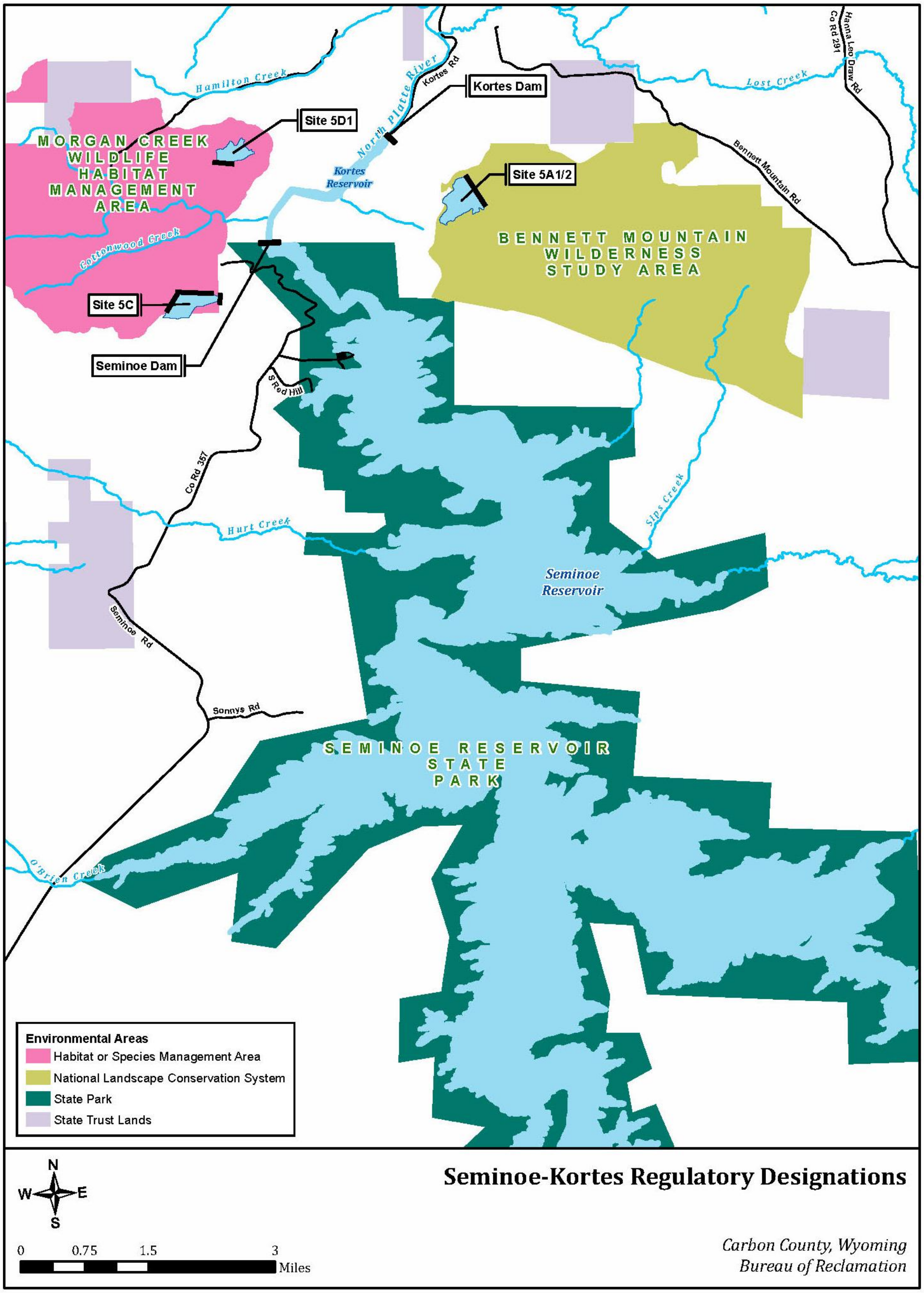
USFWS has identified the following federally listed threatened or endangered species that may be present in the reservoirs' vicinity: Black-footed ferret; blowout penstemon; and Ute ladies'-tresses, which are the same species found in the vicinity of Pathfinder and Alcova reservoirs.

5.1.4 Trinity and Lewiston Reservoirs

Trinity Dam and Lewiston Dam are part of the Trinity River Division of the Central Valley Project (CVP). The Trinity River Division was authorized by an act of Congress on August 12, 1955. Section 1 of the 1955 Act provided for the construction, operation, and maintenance of the Trinity River Division. Section 2, however, specifically authorized and directed the Secretary to adopt appropriate measures to insure the preservation and propagation of fish and wildlife.

Trinity Reservoir has a total capacity of 2,448,000 acre-feet at elevation 2,450 feet. The lake offers recreation facilities for camping, boating, water skiing, swimming, fishing, and hunting. During the winter, Reclamation maintains lower levels in Trinity Reservoir to provide a buffer in the event of an

Figure 5-3. Seminoe-Kortes Regulatory Designations



extremely large winter storm. The quantity of that buffer is based on several factors, and primarily references many years of hydrologic record for the basin. The Trinity River Restoration Program (TRRP) sets annual flow release recommendations.

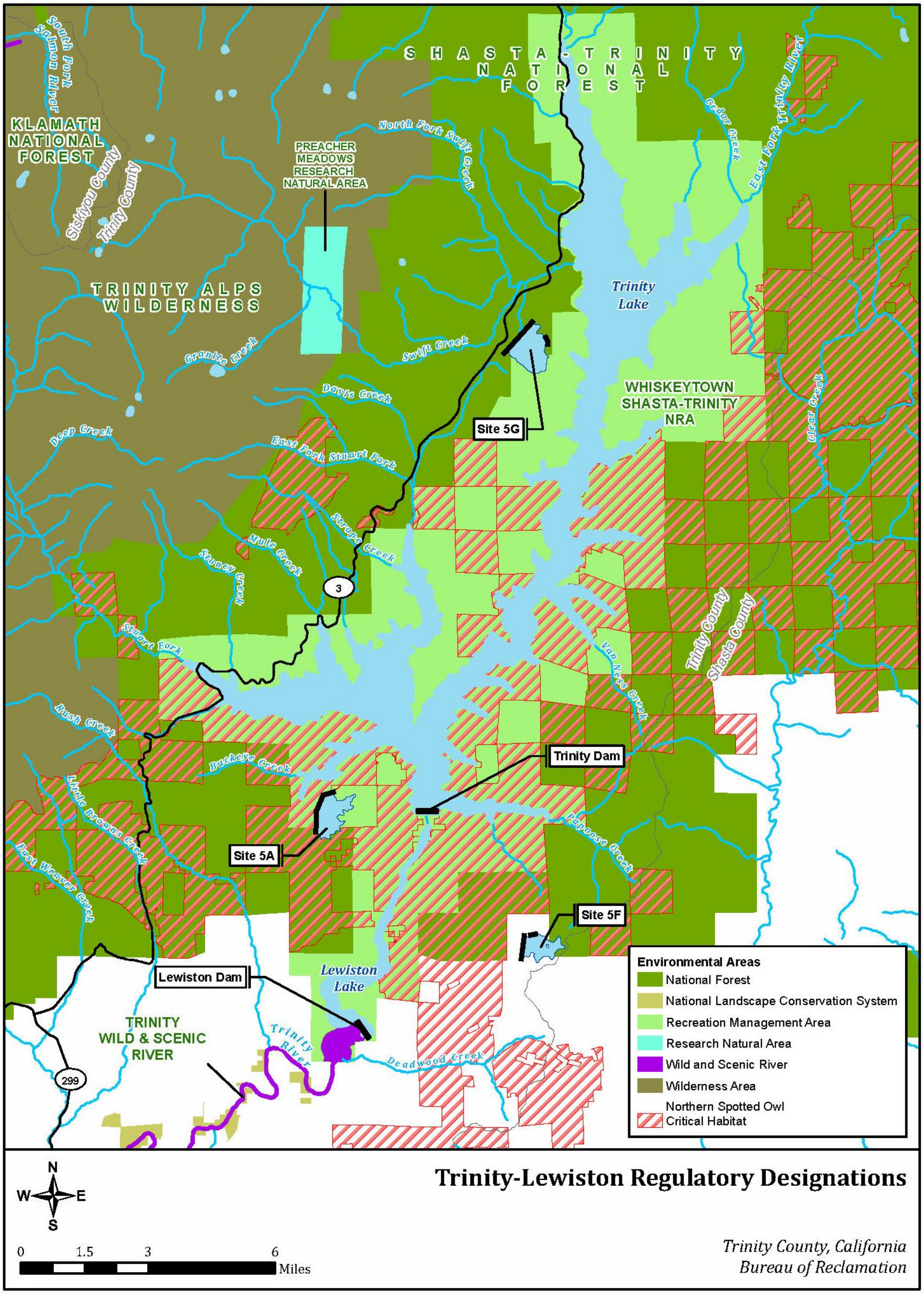
Lewiston Reservoir is about 8 miles downstream from Trinity Reservoir with a storage capacity of 14,660 acre-feet. Lewiston Reservoir releases water into the Trinity River. The Clear Creek Tunnel also conveys water from Lewiston Reservoir to Whiskeytown Reservoir, which is outside of the Trinity River basin. Reclamation makes flow releases from Lewiston Reservoir to the Trinity River for purposes such as tribal releases or to mitigate late summer conditions in the lower Klamath River for fish health purposes.

Reclamation also operates the Trinity and Lewiston reservoirs to meet temperature objectives set by the North Coast Regional Water Quality Control Board and the TRRP Record of Decision. The geometry, hydrodynamics, and incidence of direct solar radiation in Lewiston Reservoir can cause an increase in water temperature during travel of flows from Trinity Dam to Lewiston Dam, and into the Trinity River, which sometimes results in unsuitable mean daily temperatures for anadromous salmonids in the Trinity River below Lewiston Dam. The TRRP established a Temperature Workgroup that is investigating alternatives to improve transmission of coldwater through Lewiston Reservoir into the Trinity River.

Figure 5-4 shows regulatory designations associated with Trinity and Lewiston reservoirs. Both reservoirs are in the Whiskeytown-Shasta-Trinity NRA, which includes 246,087 acres managed by the United States Forest Service (USFS) and the National Park Service (NPS). Specifically, the USFS manages Shasta, Trinity and Lewiston reservoirs, and the NPS manages Whiskeytown Reservoir. This NRA offers a diverse range of high quality outdoor activities including camping, fishing, swimming, paddling, boating, backpacking, horseback riding, mountain biking, off-roading, wildlife viewing, and hunting. Trinity Reservoir offers a wide variety of flat water recreation. Lewiston Reservoir has recreation limited to non-contact activities. The NRA is encompassed within the Shasta-Trinity National Forest, which is the largest national forest in California. The Klamath National Forest is on the west boundary of the Shasta-Trinity National Forest.

The Trinity River, from 100 yards below the Lewiston Dam to the confluence with the Klamath River, is designated a Wild and Scenic River, under the National Landscape Conservation System. This entire stretch of river is federally designated under the Wild and Scenic System to preserve its Outstandingly Remarkable Values, which includes the river’s free flowing condition, anadromous and resident fisheries, outstanding geologic resource values, scenic values, recreational values, cultural and historic values, and the values associated with water quality. The segment of the Trinity River is also

Figure 5-4. Trinity-Lewiston Regulatory Designations



classified as a Recreational River by the Bureau of Land Management and the Shasta-Trinity National Forest (TRRP 2009). The project vicinity has designated critical habitat for the federally-listed Northern Spotted Owl. USFWS issued a final rule in December 2012 for a revised designation of critical habitat for the Northern Spotted Owl (TRRP 2009). The federally threatened California red-legged frog has also been known to occur in Trinity County.

The Trinity River also supports anadromous fisheries, including the federally-listed coho salmon. The TRRP was established by the Trinity River Mainstem Fishery Restoration Record of Decision (2000) with the over-arching goal of restoring the natural production of salmon and steelhead below Lewiston Dam. The TRRP is a multi-agency program with eight partners that form the Trinity Management Council, plus numerous other collaborators. The Trinity Management Council partners include the California Resources Agency, Hoopa Valley Tribe, Trinity County, Reclamation, USFWS, USFS, National Marine Fisheries Service, and the Yurok Tribe.

Reclamation provides annual in-stream flows below Lewiston Dam to restore and maintain the Trinity River's fishery resources. These restoration flow releases have two essential purposes: 1) to provide physical fish habitat (i.e. appropriate depths and velocities, and suitable temperature regimes for anadromous salmonids); and 2) to restore the riverine processes that create and maintain the structural integrity and spatial complexity of the fish habitats. The TRRP develops annual flow release requirements through a collaborative process with public input (TRPP 2009).

The Trinity River is an important resource to Indian tribes in the Klamath Basin. The Trinity River flows through the Hoopa Valley Reservation, downstream of Lewiston Reservoir, near the confluence with the Klamath River. The Yurok Reservation is further downstream on the river after the confluence. The Trinity River and availability of fish is significant to the tribes' culture. The Hoopa Valley and Yurok tribes use the river and its resources for ceremonial, subsistence, and commercial purposes. The tribes have federally reserved fishing rights and water rights. Reclamation must prevent activities under its control that would adversely affect Tribal rights, even when those activities take place off-reservation (TRRP 2009).

5.2 Operations, Environmental, and Regulatory Screening

This section describes the screening process and results for the remaining options. For the Phase 1 evaluation, these analyses were qualitative based on existing data. The Phase 2 evaluation will include quantitative operations and economic modeling.

5.2.1 Screening Methods

The Yellowtail, Pathfinder, Seminoe and Trinity sites all serve multiple purposes, which can include irrigation, municipal and industrial water supply, recreation, flood control, fish and wildlife, and hydropower. Each site has complex operating procedures and criteria in place to meet these multiple water needs. The sites are also located in generally remote, and sometimes protected, areas on major rivers that can pose environmental challenges for construction and implementation of a pump-generation project. Conflicts with operations criteria or impacts to environmental resources can be a fatal flaw for some projects. The project team collected existing information relative to operations criteria, regulatory and environmental setting, and stakeholder coordination issues to determine if there are any fatal flaws to the pump-generation options identified. In many instances, a new pump-generation project would have impacts that will be challenging to address, but may not necessarily be a fatal flaw. This screening evaluation identifies those issues and considers whether they are fatal flaws at this level of analysis.

As a first step in the screening evaluation, the project team identified potential fatal flaw criteria for a pump-generation project. These criteria relate to project operations, environmental regulations and resources, and institutional issues. Institutional issues consider existing stakeholder concerns and multiagency coordination. The project team then evaluated each of the options relative to the criteria to determine if there could be a fatal flaw. The following are the criteria considered in this analysis, which are further defined in Section 5.2.2 accompanying the evaluation results.

- Operations Criteria
  - Impacts to water storage and water supply
  - Impacts to meeting minimum flow release requirements
  - Impacts to water quality or temperature
  - Changes to existing system operations
- Environmental Criteria
  - Impacts to reservoir or riverine fisheries
  - Impacts to special status species (non-fish) and critical habitat
  - Impacts to existing reservoir or in-river recreation
  - Impacts to cultural or historic resources
  - Impacts to Native American resources

  - Impacts to land uses or regulatory designations
  - Other project construction impacts
- Institutional Criteria
  - Stakeholder conflicts

The project team used a three-level rating scale to evaluate the options relative to each criterion. The scale developed uses colors to reflect whether the option could result in a potential impact or fatal flaw relative to each criterion. In general:

- A green rating indicates the option would not have any substantial effects that could yield a fatal flaw.
- A yellow rating means that implementation of the option could have substantial effects, but they are not expected to result in fatal flaws at this time. The Phase 2 evaluation should closely monitor these potential impacts and quantify them, if possible.
- A red rating means the option would result in a fatal flaw and the option is removed from further evaluation.

It is important to note that implementation of any of these options would be challenging and a green rating does not indicate that there are no potential project impacts. This screening evaluation is set up for a relative comparison among the options to understand which ones may have fewer challenges relative to others.

5.2.2 Screening Results

This section presents the screening evaluation results of the options relative to each criterion. The purpose of this screening analysis is to determine potential fatal flaws of the options and to compare potential issues and impacts of the options against one another. At this level of analysis, only one fatal flaw was found for the options. Quantification of some impacts during the Phase 2 evaluation may determine fatal flaws, but it cannot be determined with a qualitative analysis at this time. These impacts were given a yellow rating for further evaluation during Phase 2.

Tables 5-6 through 5-17 describe how the ratings were derived for each option. Options that rate the same relative to the impact for the same reasons are grouped together. Table 6-1 in Chapter 6 summarizes the screening results.

5.2.2.1 Operations Criteria

These criteria evaluate the effects a new pump-generation project could have on existing Reclamation project operations. As discussed above, all of the reservoirs evaluated are part of a larger Reclamation project that meets multiple uses. Some effects to existing operations could be a fatal flaw for a pump-generation project. In general, a pump-generation project would pump the usable volume from a lower reservoir into an upper reservoir. The same volume of water would then be released from the upper reservoir back into the lower reservoir to generate power. The options for this evaluation would generate 10 hours of energy storage. The project team rated the operations criteria conservatively. Several options have elevation and release requirements that would be challenging for a pump-generation operation, but without a more detailed operations analysis, it is difficult to determine if these operations requirements would be a fatal flaw. The Phase 2 evaluation includes an operations model.

Reservoir Elevations and Storage Requirements

A pump-generation project could change reservoir elevations and affect potential storage requirements in an existing reservoir. This criterion considers potential effects to elevations and storage as a result of the option. At this level of analysis, the options were developed to operating within the active storage pool for the existing reservoirs. Also, there would not be a net change in volume with a pump-generation project relative to existing conditions. For the Concept 5 options, the new upper reservoir would be dedicated to pump-generation options and designed to accommodate pump-generation daily water levels changes. Effects could occur in the lower reservoirs because water would be pumped out of the reservoir, thus lowering water levels relative to existing conditions. Effects would be more adverse in smaller reservoirs where most of the usable capacity would be pumped out for pump-generation. For the larger reservoirs (Bighorn, Pathfinder, Seminoe, and Trinity), the proposed volumes for pump-generation are small relative to the size of these reservoirs. Therefore, there would not likely be a major change in elevation with the proposed options. Table 5-6 lists how the options rate relative to this criterion.

Table 5-6. Options Rating relative to Reservoir Elevations and Storage Requirements Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A and 5B	Green	Bighorn Lake has operating criteria for lake levels throughout the year to support recreation and fisheries. Pumping the proposed usable volume of the new reservoirs would not affect lake elevations or storage in Bighorn Lake, which has over 1.3 million AF capacity.
Yellowtail 4YA-1 and 4YA-2; Trinity 4TL	Yellow	Yellowtail options pump water out of Yellowtail Afterbay and Trinity option pumps out of Lewiston Reservoir, which have relatively small operating ranges. The proposed usable volume for the options would remain within the operating range but additional release requirements could affect elevations in Yellowtail Afterbay and Lewiston Reservoir.
Pathfinder 5A1;Seminoe 5A1,5A2,5C and 5D1; Trinity 5A-B,5F,5G2-A and 4TL	Green	The options would not affect storage or lake elevations primarily because of the size of the project relative to the size of the existing lower reservoir. Seminoe 5A1 and 5D1 use Kortes Reservoir as a lower reservoir. The lake elevations would likely go lower than existing conditions, but a new stream augmentation feature would allow continued releases.
Pathfinder 5D	Yellow	This option has Alcova Reservoir as the lower reservoir. There is a two-foot operating range for Alcova during summer months for delivery to Casper Canal. The reservoir is also operating 10 feet lower during the winter months to prevent ice damage. Pump-generation operations could potentially pose challenges to meeting the 2 foot operating range.

Minimum Flow Requirements

Most of the existing reservoirs have minimum flow release requirements throughout the year. A pump-generation project could affect the ability to meet release requirements if stored water must be pumped to an upper reservoir. Kortes Reservoir has requirement to release 500 cfs all year for fish flows. Reclamation operates the reservoir near the spillway in order to maintain these flows in the event that the power outlet if offline (the only outlet in the reservoir). The project team included a stream augmentation feature for all options that use Kortes Reservoir as a lower reservoir, so the minimum flows can be maintained. Table 5-7 shows how the options perform relative to the ability to meet minimum flow release requirements.

Table 5-7. Options Rating relative to Minimum Flow Requirements Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A and 5B	Green	Bighorn Lake has minimum fish flow releases of 1,500 cfs and the absolute minimum flow release 1,000 cfs. These options use Bighorn Lake as a lower reservoir, which has a large usable volume. With these options, the flow requirements could still be met because the pump-generation project is very small compared to the Bighorn Lake active pool volume.
Yellowtail 4YA-1 and 4YA-2	Yellow	Yellowtail Afterbay would be the lower reservoir for these options. There is a small operating range and volume in the Afterbay. It would be very challenging to pump water out of Yellowtail Afterbay for pump-generation, while still meeting flow requirements.
Pathfinder 5A1 and 5D	Green	WYGF requires a year round flow of 75 cfs through the Pathfinder Reservoir to the river below Pathfinder Dam. This flow would likely be maintained because of the size of usable volume at Pathfinder Dam relative to the size of the pump-generation projects.
Seminoe 5A1,5A2,5C and 5D1	Green	Options 5A2 and 5C use Seminoe Reservoir as a lower reservoir. Flow releases could be met because of the relative size of Seminoe Reservoir to the new reservoir. For Options 5A1 and 5D1 that use Kortes Reservoir as a lower reservoir, the project team has included a stream augmentation so that the flow requirements could be met.
Trinity 5A-B and 5G2-A	Green	TRRP sets downstream flow requirements. These requirements would be met with Trinity Reservoir as a lower reservoir. These options' usable volume is small relative to the size of Trinity Reservoir and would not affect ability to release flows.
Trinity 5F and 4TL	Yellow	TRRP sets downstream flow requirements. These requirements might be hard to meet with Lewiston Reservoir as the lower reservoir.

Water Quality and Temperature Requirements

This criterion measures an options potential effect to water quality or temperature in existing reservoirs and downstream rivers. Trinity River has temperature requirements for fisheries that vary throughout the year depending on the fish life cycle. A potential pump- generation project cannot affect the ability to meet temperature standards. Lewiston Reservoir has existing temperature issues that make it difficult to meet these requirements under existing conditions. A new pump-generation project using Lewiston Reservoir could change the existing temperature in Lewiston Reservoir. The Phase 2 evaluation will evaluate if water temperatures in Lewiston would increase with the project or if pump-generation can be designed to help lower temperatures to help meet temperature requirements. Yellowtail Afterbay operates within a smaller operating range to limit use of the sluice gates that cause nitrogen supersaturation downstream, which can affect fish. This smaller operating range affects the usable volume in Yellowtail Afterbay and the resultant installed capacity. Table 5-8 lists how the options perform relative to relative water quality and temperature requirements.

Table 5-8. Options Rating relative to Water Quality and Temperature Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A, 5B, and 4YA-2; Pathfinder 5A1 and 5D; Seminoe 5A2 and 5C	Green	No potential water quality issues have been identified relating to this criterion at these sites.
Yellowtail 4YA-1	Red	Because of water quality issues at Yellowtail Afterbay, the option cannot operate the afterbay to an elevation of 3,153 feet. Reclamation is completing a Yellowtail Afterbay Rehabilitation Project, but the operating level will not be at 3,153 feet with this project.
Seminoe 5A1 and 5D1	Yellow	State of Wyoming has classified water downstream of Kortes as a Class 1 water body i.e. water body with no water quality degradation. The Phase 1 evaluation identifies this as a potential issue, but does not assume this is a fatal flaw at this level of analysis.
Trinity 5A-B and 5G2-A	Green	TRRP ROD and Basin Plan have identified Trinity River temperature requirements. This is not likely an issue with Trinity Reservoir as a lower reservoir due to size of the new reservoirs under these options.
Trinity 5F and 4TL	Yellow	TRRP ROD and Basin Plan have identified Trinity River temperature requirements. Meeting these requirements could be an issue with Lewiston as lower reservoir because Lewiston already has higher temperatures.

System Reoperation

This criterion measures whether or not the pump-generation option would require reoperation of additional reservoirs in the system other than the proposed forebay and afterbay to operate the power plant at maximum capacity. This can add to the complexity of pump-generation operations. System reoperation would likely be required for Concept 5 options where the proposed new reservoir connects to the smaller, existing afterbay (Alcova, Kortes, and Lewiston Reservoirs). For these options, the usable volumes of the lower and upper reservoirs are similar, so the majority of water is used for pump-generation. In some years with low storage, other reservoirs in the system would likely need to make additional releases to allow the pump-generation project to operate at maximum capacity and accommodate other water releases. Table 5-9 lists how the options relate to this criterion.

Table 5-9. Options Rating relative to System Reoperation Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A, 5B,4YA-1 and 4YA-2; Pathfinder 5A1; Seminoe 5A2 and 5C;Trinity 5A-B,5G2-A and 4TL	Green	These Concept 5 options connect to the larger existing reservoir and would not require system reoperations. The Concept 4 options would require changes in operations of only the proposed forebay and afterbay. No potential issues have been identified relating to this criterion at these sites.
Pathfinder 5D	Yellow	This option uses Alcova as the lower reservoir and would require reoperation of Pathfinder to achieve maximum power generation. Operationally, Pathfinder is a bottleneck in the system with its restricted release capability of approximately 6,000 cfs.
Seminoe 5A1 and 5D1	Yellow	These options use Kortes as a lower reservoir. The pump-generation project would require additional releases from Seminoe Reservoir relative to existing conditions to operate at maximum capacity.
Trinity 5F	Yellow	This option uses Lewiston as a lower reservoir. This option would require additional releases from Trinity Reservoir relative to existing conditions to operate at maximum generation capacity.

5.2.2 Environmental Criteria

Constructing and operating a pump-generation project could affect existing environmental resources. The environmental screening process evaluates whether implementation of the options could have environmental impacts that would result in fatal flaws. Any project considered for implementation would need to comply with the National Environmental Policy Act (NEPA), Endangered Species Act (ESA), National Historic Preservation Act and other federal and state equivalent environmental laws.

Fisheries Issues

Changes in river flows, lake elevations, and water temperatures can affect fisheries habitat and life cycles; therefore, effects to fisheries are closely related to water operations. The existing reservoirs are on rivers that support fisheries important to the region. Some of the reservoirs must make releases to sustain the fisheries. Bighorn River and the North Platte River support trout fisheries that attract anglers nationwide and are important for the region's economy. The Trinity River supports anadromous fish species that are listed under the ESA, important commercial fisheries, and/or culturally significant to Indian tribes in the region. The existing reservoirs also provide game fishing. The proposed new reservoirs under Concept 5 options would affect some watershed drainages as a result of inundating land and constructing a new dam. The proposed sites are upstream of major dams that have block historic fish passage; therefore, the new dams would not add further obstruct upstream fish passage. Fisheries will be an issue for a pump-generation project at all sites. Table 5-10 rates potential fisheries issues at each site, in comparison to one another. At this time, there are no fatal flaws identified for fisheries, but further planning will require significant coordination and consultation with federal and state fisheries agencies.

Table 5-10. Options Rating relative to Fisheries Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A and 5B; Pathfinder 5A1 and 5D; Seminoe 5A2 and 5C;Trinity 5A-B,5G2-A	Green	No potential issues have been identified relating to this criterion at these sites. These options include new reservoirs that would connect to the larger existing reservoir. There are no expected changes to in-reservoir fisheries habitat or ability to meet fish flow releases.
Yellowtail 4YA-1 and 4YA-2	Yellow	Bighorn Lake and Bighorn River offer premier fishing in Montana. Use of the Yellowtail Afterbay as a lower reservoir could affect releases into Bighorn River to meet fish flows. Impacts to fisheries in Bighorn Lake are not expected due to the size of the lake and proposed project.
Seminoe 5A1 and 5D1	Yellow	The Miracle Mile is downstream of Kortes Reservoir and is a premier fishing area for Wyoming. Pump-generation operations could pose challenges to meeting flow requirements and could result in impact to fish habitat and populations.
Trinity 5F and 4TL	Yellow	Use of Lewiston as a lower reservoir could affect the ability to meet minimum fish flow requirements. Changes in temperature in Lewiston Reservoir might also increase due to the pump-generation project and could affect temperature of water releases into Trinity River, affecting downstream fish habitat.

Special Status Species and Critical Habitat

The criterion applies to non-fish species because fish issues are assessed above. Construction activities could affect special status species by disturbing habitat, limiting breeding grounds, or taking. New reservoirs under Concept 5 options would permanently remove land that could be special status species habitat or designated critical habitat. For any potential effects to listed species, Reclamation would need to consult with USFWS under Section 7 of the ESA. Reclamation would need to implement conservation or mitigation measures to avoid or reduce potential effects. Special status species have been in documented in the vicinity of all the reservoirs. This analysis assumes that Reclamation can coordinate with USFWS to minimize effects and this would not be a fatal flaw at this level of analysis. Only projects at the Trinity site would affect designated critical habitat.

Table 5-11. Options Rating relative to Special Status Species and Critical Habitat Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A ,5B, 4YA-1 and 4YA-2; Pathfinder 5A1 and 5D; Seminoe 5A1, 5A2 and 5C	Green	These options would likely require consultation with the USFWS and implementation of conservation measures. This is not assumed to be a fatal flaw at this time.
Trinity 5G2-A	Green	Option is outside of critical habitat designation for Northern Spotted Owl.
Trinity 5A-B, 5F, and 4TL	Yellow	Proposed reservoir is in critical habitat for Northern Spotted Owl.

Recreation

The four sites offer multiple water and land based recreation opportunities that are recognized statewide for their quality. Recreation is also important for the region's economy by attracting visitors. Project construction and operations could affect recreation in the reservoirs, downstream rivers, and nearby areas. Project construction effects to recreation would be temporary and could likely be mitigated or avoided. Concept 5 options would permanently convert land in recreation areas to reservoirs. Potential impacts would vary based on the existing activity in the proposed reservoir area and nearby opportunities. At this time, conversion of land to new reservoirs is not assumed a fatal flaw. Project operations could affect lake levels for recreation and releases for downstream recreation activities. Changes in lake elevations in the large reservoirs would not likely be noticeable for recreation and not expected to be an issue. Operations in the smaller reservoirs could have a more noticeable effect to reservoir recreation, but there are similar recreation opportunities nearby in the larger reservoirs. Changes in flow releases could affect the quality of downstream recreation activities, but there would be no changes in opportunity as a result of the pump-generation project. The project team does not expect pump-generation projects to result in fatal flaws relative to recreation activities at this point in the analysis.

Cultural and Historic Resources

Project construction could affect cultural and historic resources. Pathfinder Dam is the only listed historic site among the four areas. Construction of the Pathfinder options would occur away from the dam and would not likely have adverse effects. Construction could also reveal and potentially affect unknown archaeological resources. For any potential effects, Reclamation would need to consult under Section 106 of the National Historic Preservation Act and identify appropriate mitigation. At this point in the analysis, there would be no fatal flaws or major issues associated with cultural and historic resources.

Native American Resources

Project construction and operations could affect Native American resources, including federally reserved rights, tribal holdings, and culturally significant resources. Both Trinity and Yellowtail sites have Indian tribes within the region. In the Trinity Region, the Hoopa Valley and Yurok tribes have federally reserved fishing and water rights and their cultures are closely linked to the salmon in the Trinity River. For Yellowtail, the Crow tribe owns much of the land surrounding the reservoir and has tribal holdings within Bighorn Canyon National Recreation area. The proposed reservoirs for Yellowtail Options 5A and 5B are on tribal holdings. Potential effects to tribal resources would require government-to-government consultation and continued coordination throughout the planning process. For both Trinity and Yellowtail, the tribes are active stakeholder in existing operations and restoration programs. At this point in the analysis, potential effects to tribal resources would not be a fatal flaw in the analysis, but it would require tribal consultation and agreements and could add substantial costs to the options. Table 5-12 shows how the options rate according to this criterion.

Table 5-12. Options Rating relative to Cultural and Native American Resources Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A ,5B	Yellow	Crow and Northern Cheyanne tribes have rights to storage in Bighorn Lake. The Crow Tribe Water Rights Settlement Action of 2010 defines water rights. The Crow Tribe also has land holdings where the proposed new reservoirs are located. The project would need to be closely coordinated with the Crow Tribe, but it not a fatal flaw at this point in the analysis.
Yellowtail 4YA-1 and 4YA-2, Trinity 5G2-A and 5A-B	Green	Crow tribe has water rights, but operations would not affect them. Construction is at Reclamation facilities, off of tribal lands. Hoopa Valley and Yurok tribes have reserved fishing and water rights on the Trinity River, but these Trinity Options may not affect river flows.
Pathfinder 5A1 and 5D; Seminoe 5A1, 5A2 and 5C	Green	No potential issues with Native American resources.
Trinity 5Fand 4TL	Yellow	Hoopa Valley and Yurok tribes have reserved fishing and water rights on the Trinity River. Options 5F and 4TL have challenges because they could affect fish and flows, as described in above criterion. The project would need to be closely coordinated with the tribes, but it not a fatal flaw at this point in the analysis.

Land Use and Regulatory Designations

This criterion evaluates whether any of the options would conflict with existing land uses or regulatory designations, such as National Parks, National Wildlife Refuges, National Forests, and others that could potentially affect development. The proposed new reservoirs are in remote areas away from urban centers and would not have any effects to city or community land use planning. Some of the proposed options are in areas designated under the National Landscape Conservation System, which includes Wilderness Study Areas, Wild and Scenic Rivers, and other wilderness designations. None of the designations would preclude development, so this is not a fatal flaw at this time. Reclamation would need to purchase land if it not on federally-owned property, which would add to the costs of the projects. This analysis assumes that land acquisitions could occur. Table 5-13 shows how the options rate according to this criterion.

Table 5-13. Options Rating relative to Regulatory Designation Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A ,5B, 4YA-1 and 4YA-2	Yellow	Options are located in the Bighorn Canyon National Recreation Area, managed by NPS. As described above, the new reservoir sites for Options 5A and 5B are on tribal holdings.
Pathfinder 5A1 and 5D	Green	The proposed new reservoir sites are not in any designated areas.
Seminoe 5A1, 5A2 and 5C	Yellow	Seminoe Reservoir is in a State Park and proposed new reservoirs are in either Bennett Mountain Wilderness Study Area or Morgan Creek Wildlife Habitat Management Area.
Trinity 5A-B,5F, 5G2-A and 4TL	Yellow	Options are located within a National Forest and National Recreation Area. The Trinity River below Lewiston is Wild and Scenic River and potential effects could require a determination under the Wild and Scenic Rivers Act.

Construction Impacts

This criterion addresses construction effects, such as land disturbance, vehicle access, construction footprint, and overall complexity of construction efforts. The above criteria discuss construction impacts to specific resources. This criterion accounts for other construction impacts or challenges. Most of these sites are in remote areas with few roads and access points. Large construction vehicles hauling materials would have difficulty accessing some areas. There are also few nearby areas that could accommodate the influx of workers. Worker camps may need to be set up near the construction sites. Construction equipment and vehicles would also increase air pollutant emissions. Some of these effects could be offset by the renewable energy generated by the options. The Concept 5 options with new reservoirs would cause more land disturbance than Concept 4 options and would require much more hauling and larger staging areas for dam construction. Table 5-14 presents option ratings relative to construction impacts.

Table 5-14. Options Rating relative to Construction Impacts Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A and 5B; Pathfinder 5A1 and 5D; Seminoe 5A1, 5A2 and 5C; Trinity 5A-B, 5F and 5G2-A	Yellow	Concept 5 options would have more construction effects because of the activity required for building new reservoirs. Seminoe Options 5A2 and 5C have the largest proposed dam volumes of all options, over 8.0 million cubic yards. Construction impacts could be mitigated, but these are major construction projects likely to result in some adverse environmental impacts. Because mitigation could be available, these are not fatal flaws assumed at this point in the analysis.
Yellowtail 4YA-1 and 4YA-2; Trinity 4TL	Green	Construction at existing facilities would also have environmental impacts, but would likely be less than building new reservoirs.

Stakeholder Issues

Reservoir operations affect irrigation, hydropower, recreation, tribal needs, environmental and fishery needs, water quality and flood control, all of which are represented by different stakeholders with varying interests. A new pump-generation project would introduce a new issue into the already complex operations of these projects and will likely generate stakeholder interest and concerns. For some sites, stakeholders have worked together to develop plans and programs to better manages shared resources, such as the TRRP, Pathfinder-Alcove-Gray Reef Resources Management Plan, and Bighorn River Operating Criteria. Stakeholder issues will be challenging for each option and stakeholder coordination is necessary for a new project at any site. TRRP and Bighorn River System Issues Group are already established groups that represent multiple stakeholders. Working with these groups to further understand issues and define a pump-generation project that supports existing objectives would be beneficial. Stakeholder issues will be difficult to address, but they are not a fatal flaw at in this evaluation. Table 5-15 presents option ratings relative to stakeholder issues.

Table 5-15. Options Rating relative to Stakeholder Issues Criterion

Option(s)	Rating	Rating Explanation
Yellowtail 5A ,5B, 4YA-1 and 4YA-2	Yellow	Project must be coordinated with the Bighorn River Systems Issues Group, state, federal, local agencies, tribes.
Pathfinder 5A1 and 5D; Seminoe 5A1, 5A2, 5C and 5D1	Yellow	Project would require coordination with the States of Wyoming, Nebraska and Colorado and other federal and local agencies.
Trinity 5A-B,5F, 5G2-A and 4TL	Yellow	Project would require coordination with the TRRP, Central Valley Project operators, and other federal and local agencies.

Table 6-2 in Chapter 6 summarizes the screening results for the options relative to all the above criteria.

5.3 Economic Evaluation

For the Phase 1 evaluation, the economic analysis is based on the relative cost-effectiveness of the options to achieve one MW capacity. Therefore, the cost-effectiveness measurement is $/MW installed capacity. A cost-effectiveness analysis can be used to compare the pump-generation options to one another, but does not give an estimate of the economic benefits of the option developing new power and ancillary services. The economic benefits are the value of energy generated, net of pump energy, plus the value of ancillary services. The paragraphs below Table 5-16 consider potential pump-generation benefits related to energy arbitrage and ancillary services qualitatively. The project team will quantify benefits in the Phase 2 evaluation. The economic evaluation also considers market demand and potential for renewable energy integration, particularly wind energy. These issues are discussed generally at this level and will be further investigated in the Phase 2 evaluation.

Table 5-16 summarizes the cost-effectiveness evaluation for the remaining options. The last column ranks the options based on lowest $/MW installed capacity.

Table 5-16. Cost-Effectiveness Analysis

Site	Option	Resulting Installed Capacity (MW)	Energy Storage (MWh)	Construction Cost (in million)	$/MW Installed Capacity (in million)	Cost Ranking ($/MW)
Yellowtail	5A	1,660	16,601	$2,081	$1.25	1
Yellowtail	5B	1,607	16,067	$2,141	$1.33	2
Trinity	5G2-A	1,024	10,245	$1,885	$1.84	3
Trinity	5F	615	6,151	$1,223	$1.99	4
Yellowtail	4YA-1	112	1,123	$233	$2.07	5
Seminoe	5C	572	5,715	$1,235	$2.16	6
Pathfinder	5A1	575	5,745	$1,251	$2.18	7
Seminoe	5A2	773	7,734	$1,765	$2.28	8
Trinity	4TL	111	1,112	$256	$2.31	9
Pathfinder	5D	708	7,082	$1,696	$2.39	10
Trinity	5A-B	765	7,654	$1,862	$2.43	11
Yellowtail	4YA-2	54	536	$133	$2.48	12
Seminoe	5D1	266	2,664	$664	$2.49	13
Seminoe	5A1	277	2,767	$860	$3.11	14

5.3.1 Power Sales Benefits

Pump-generation projects can provide a method for bulk storage of electrical power and other products in an economic and regulatory environment where storage of the power generated by renewable energy development continues to rise. State and federal government policy and increasing prices of fossil fuels have increased the interest in development of pumped generation.

The economic value of pump-generation is composed mainly of energy arbitrage and ancillary services. The principal of arbitrage is that power generated during off-peak hours are used to pump to a system's forebay and generate during peak hours discharging into an afterbay. Economic benefit is derived from pumping during off-peak periods and generating during peak periods. The difference can result in an economic benefit. Energy arbitrage is typically less than 10 percent of the total benefits from a pump-generation facility.

Ancillary services (or products) consist mainly of load balancing, reserve generation and storage and network operations. The bulk storage provided by pump-generation allows the balancing of generation and load and managing bulk transmission.

Location is important to realizing the economic potential of pumped generation. Markets for ancillary services are very immature to non-existent in many areas. This is true of the Yellowtail, Pathfinder and Seminoe sites in the Great Plains region. The opposite is true of the Trinity site in the Mid-Pacific region where markets for ancillary services are continuing to be developed. These issues will be more thoroughly vetted during the Phase 2 evaluation. Transmission availability will also be further documented in the Phase 2 evaluation.

5.3.2 Power Marketing

There are a number of important issues related to marketing output from new pumped generation projects. The sizing of turbines and the path of power from production to the point of demand are critical. It is critical to match output with demand and secure transmission to get the power to market. It is clear that utilities will need to meet renewable portfolio standards (RPS).

As shown in Table 5-16, the proposed pump-generation options could generate up to 16,601 MWh at Yellowtail, 7,734 MWh at Seminoe, 7,082 MWh at Pathfinder, and 10,245 MWh at Trinity. The existing reservoirs are located in relatively rural areas away from the major population areas of their respective states; therefore, there may not significant electricity demands in the immediate areas of the proposed options. Energy could be delivered to areas of higher demands. The following is a brief discussion of load forecasts of several of the major electricity providers near the Yellowtail, Seminoe/Pathfinder, and Trinity sites. The Phase 2 evaluation will further investigate local energy needs in the site vicinities.

PacifiCorp – PacifiCorp serves approximately 1.7 million customers in 6 western states - Oregon, Washington, California, Utah, Wyoming, and Idaho. In the 2011 Integrated Resources Plan, PacifiCorp identifies a need for a significant amount of new resources to offset load growth and expiration of long-term purchase power contracts. Without new resources, the system experiences a capacity deficit of 326 MW in 2011 and 3,852 MW by 2020 (PacifiCorp 2011).

Northwestern Energy – Northwestern Energy serves approximately 340,000 customers in Montana. In the 2011 Electricity Supply Resource Procurement Plan, Northwestern Energy forecasts average annual load growth for all customer classes at 1.2% over a 20-year period. In 2012, retail load excluding future energy saving was estimated to be 6,510,000 MWh. It is projected to increase to 8,210,000 MWh by 2031. Energy savings could decrease retail load by up to 749,000 MWh in 2031. Based on the forecasts and portfolio planning, Northwestern Energy identifies the need to acquire resources to meet unfilled load-serving obligations in the 20-year planning horizon.

Idaho Power – Although Idaho Power service area does not include the proposed sites, it is a major utility serving Idaho and much of the Pacific Northwest. The number of customers in Idaho Power’s service area is expected to increase from approximately 492,000 in 2010 to over 650,000 by the end of the planning period in 2030. Even with the recent recession, population growth in Idaho Power’s service area will require the company to add physical resources to meet the energy demands of its growing customer base (Idaho Power 2011). The median or peak-hour load forecast predicts peak-hour load will grow from 3,334 MW in 2011 to 4,643 MW in 2030. Median average monthly energy use is forecasted to increase from 1,189 MW in 2011 to 2,362 MW in 2030 (Idaho Power 2011).

If energy generated at the proposed options can be delivered to various regions, power demands in the immediate project areas may not be an issue. Rather, the issue becomes available transmission capacity or potential bottlenecks in the transmission system. Utilities, including some of those described above are upgrading existing transmission systems. Western Area Power Administration (Western), an agency of the U.S. Department of Energy, markets and delivers electricity from Federal projects to 15 states in central and western U.S. Western also transmits non-Federal power through its transmission system. Available transmission capacity is sold on the Open Access, Same Time Information System (OASIS). Western also has plans for transmission expansion, either as the lead agency or a partner. The Phase 2 evaluation will further investigate available transmission capacity.

Another important consideration in power planning is meeting a RPS, which is a regulation that requires a percentage of energy production from renewable resources. Therefore, utilities must have renewable resources to meet a portion of their customer demands. Montana has an RPS that requires utilities to obtain 15% of electricity sales from renewable resources by 2015. California requires utilities to have 1/3 of their retail sales from renewable resources by 2020. Wyoming does not have a RPS. The section below describes renewable energy integration.

5.3.3 Renewable Energy Integration

A pump-generation project could support the integration of variable generation resources, including wind energy development. Many utilities have developed or have plans to develop wind resources to meet a RPS and need to integrate wind generation into the grid. Therefore, a proposed pump-generation project in an area of high wind energy potential and planned wind development could make the project more economical.

The U.S. Department of Energy has developed the Wind Program to accurately define, measure, and forecast the nation's land-based and offshore wind resources. The Energy Department, the National Renewable Energy Laboratory, and AWS Truepower developed a wind resources map that shows wind resources estimated at an 80-m height for all 50 states and offshore resources up to 50 nautical miles from shore (available at: http://www.windpoweringamerica.gov/wind_maps.asp). Table 5-17 summarizes the wind energy potential estimated in California, Montana, Wyoming, and the U.S. Montana ranked 3rd, Wyoming ranked 8th, and California ranked 20th of the 50 states in regards to total installed capacity.

Table 5-17. Windy Land Area >= 30% Gross Capacity Factor at 80m and Wind Energy Potential in California, Montana, and Wyoming

	Windy Land Area >= 30% Gross Capacity Factor at 80m					Wind Energy Potential	
State	Total (km^2)	Excluded[1] (km^2)	Available (km^2)	Available % of State	% of Total Windy Land Excluded	Installed Capacity (MW)	Annual Generation (GWh)
California	26,901.3	20,079.2	6,822.0	1.67%	74.6%	34,110.2	105,646
Montana	232,768.6	43,967.7	188,800.9	49.60%	18.9%	944,004.4	3,228,620
Wyoming	146,166.2	35,751.7	110,414.5	43.58%	24.5%	552,072.6	1,944,340
U.S. Total	2,988,328	796,945	2,191,382	22.36%	26.7%	10,956,912	38,552,706

[1] Excluded lands include protected lands (national parks, wilderness, etc.), incompatible land use (urban, airport, wetland, and water features), and other considerations.

Source: NREL and AWS Truepower 2010

The Bureau of Land Management (BLM) manages extensive public lands that have the potential to make significant contributions to the United States renewable energy portfolio, including 20.6 million acres with wind potential. In 2005, BLM approved a Record of Decision for the Wind Energy Development Program to support development of wind energy resources on BLM-administered lands in 11 western states, including California, Montana, and Wyoming. The decision established policies and best management practices (BMPs) for the administration of wind energy development activities and established minimum requirements for mitigation measures.

In Wyoming, BLM has estimated that 43 percent of the public lands in have wind energy development potential (BLM 2012a). The public lands in the southern half of Wyoming have the highest potential for wind energy development, where the Seminoe and Pathfinder sites are located. In October 2012, the Department of the Interior approved the Chokecherry and Sierra Madre Wind Energy Project site as suitable for wind energy development. The project is a proposed complex that could generate up to 3,000 megawatts of power south of Rawlins in Carbon County, which is near Seminoe Reservoir. The proposed project would consist of two sites encompassing up to 1,000 wind turbines on approximately 219,707 acres of land (U.S. Department of the Interior 2012). BLM has identified a lack of power transmission infrastructure in areas of Wyoming with high wind potential because they are generally remote and mostly unpopulated (BLM 2012a). This could be a limiting factor to wind development.

BLM is also emphasizing development of wind resources in Montana. In the past, wind energy companies have expressed interest in BLM lands in Montana in the vicinity of Bridger, Whitehall, and Glasgow. Bridger is about 70 miles from Bighorn Lake. Projects continue to be proposed all across Montana in a number of counties. However, the distance from current transmission infrastructure and limited grid capacity continues to be a challenge for wind developers in Montana (BLM 2012b).

In California, most wind energy development has been focused in the desert regions of Southern California. However, California does have goal for California's utilities to generate one third of their electricity from renewable sources by 2020, which will require new renewable energy development.

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Chapter 6
Summary and Conclusions

This section summarizes the Phase 1 evaluation results and compares options relative to one another based on technical features, operational, environmental and regulatory characteristics and economic potential. The project team initially identified 46 pump-generation options at the four sites; Yellowtail, Pathfinder, Seminoe, and Trinity. Based on technical criteria, the 46 options were screened down to 14 remaining options that had technical merit for further evaluation, including conceptual layouts, cost opinions, operational, regulatory and environmental screening, and an economic assessment. Table 6-1 summarizes the 14 options.

Table 6-1. Remaining Options Summary

Site	Option	Upper Reservoir	Lower Reservoir	Resulting Installed Capacity (MW)
Yellowtail	5A	New Reservoir 5A	Bighorn Lake	1,660
Yellowtail	5B	New Reservoir 5B	Bighorn Lake	1,607
Yellowtail	4YA-1	Bighorn Lake	Yellowtail Afterbay	112
Yellowtail	4YA-2	Bighorn Lake	Yellowtail Afterbay	54
Pathfinder	5A1	New Reservoir 5A1	Pathfinder	575
Pathfinder	5D	New Reservoir 5D	Alcova	708
Seminoe	5A1	New Reservoir 5A1	Kortes	277
Seminoe	5A2	New Reservoir 5A2	Seminoe	773
Seminoe	5C	New Reservoir 5C	Seminoe	572
Seminoe	5D1	New Reservoir 5D1	Kortes	266
Trinity	5A-B	New Reservoir 5A-B	Trinity	765
Trinity	5F	New Reservoir 5F	Lewiston	615
Trinity	5G2-A	New Reservoir 5G2-A	Trinity	1,024
Trinity	4TL	Trinity	Lewiston	111

6.1 Screening Summary and Comparison

Table 6-2 (at the end of this chapter) summarizes the options evaluation relative to the quantitative and qualitative criteria. The quantitative criteria are listed first and show the project capacity and costs. The qualitative criteria are listed below the quantitative criteria with the appropriate color ratings for each option. For the qualitative criteria, options with more green ratings generally perform better relative to the criteria than with more yellow ratings. A red rating indicates a fatal flaw and that the option should not be further evaluated. Criteria with ratings that are the same across all options, such as effects to cultural and historic resources, indicate that this criterion is not a major differentiator among options.

Based on the summary table, some notable observations include:

- All Concept 5 options proposed new upper reservoirs. Concept 5 options that use the larger, existing upper reservoir (Bighorn Lake, Pathfinder, Seminoe, and Trinity) as a lower pumped storage pool rated better relative to operations and environmental criteria than options that connected to the existing smaller lower reservoir (Yellowtail Afterbay, Alcova, Kortes, and Lewiston).
- Yellowtail Options 5A and 5B have the largest potential installed capacity of the 14 options and the lowest installed cost per MW at $1.25 million/MW and $1.33 million/MW, respectively. Compared to existing projects, these are competitive costs for construction of pump-generation. The proposed reservoir sites are on Crow Tribe holdings; land acquisition and/or agreements with the Crow Tribe could add substantially to the project costs. However, the existing cost estimates are almost one-third less than the third ranked option (Trinity Option 5G2-A at $1.84 million/MW).
- Of the Trinity Concept 5 Options, Option 5G2-A appears to be the most attractive relative to most criteria. It has the highest installed capacity and lowest cost per MW. Option 5G2-A is actually ranked 3rd of the 14 options in cost per MW ($1.84 million/MW). Trinity Option 5F is ranked 4th, but has only 60 percent of the installed capacity of Trinity Option 5G2-A. Relative to environmental issues, the new proposed reservoir is located near the upper end of Trinity Reservoir, which is expected to have fewer impacts to both operations at Lewiston and aquatic impacts within Trinity. Reservoir 5G2-A would also be outside of critical habitat for the Northern Spotted Owl.
- Pathfinder and Seminoe sites are both on the North Platte River and have similar operational and environmental issues. Seminoe 5C has an installed capacity of 572 MW and is ranked 6th for cost per MW ($2.16 million/MW) of all the options. Seminoe 5A2 has an installed capacity of 773 MW and is ranked 8th for cost per MW ($2.28 million/MW) of all the options. Both Seminoe 5C and 5A2 connect to Seminoe Reservoir as the lower reservoir, which would have fewer operational issues than Seminoe Options 5A1 and 5D1 that connect to Kortes Reservoir as the lower reservoir. Pathfinder Option 5A1 has an installed capacity of 575 MW and is ranked 7th for cost per MW ($2.18 million/MW) of all the options.
- Yellowtail Option 4YA-1, ranked 5th in cost, has a fatal flaw relative to water quality issues. This option assumes a minimum elevation of 3,157 feet, which is based on the reservoir profile. Because of nitrogen super saturation, Yellowtail Afterbay must be operated at a minimum

elevation of 3,183 feet. Therefore, Yellowtail Option 4YA-1 is not feasible and was screened out of the analysis.

- Two Concept 4 options are still in the analysis – Yellowtail 4YA-2 and Trinity 4TL. Both Concept 4 options for Pathfinder and Seminoe sites were screened out based on technical criteria. Yellowtail 4YA-2 would have an installed capacity of 54 MW, which is the smallest of the proposed options. Yellowtail 4YA-2 is also ranked 12th of the 14 options for $/MW costs. The project team has identified potential operational issues with using Yellowtail Afterbay as a lower reservoir in a pump-generation project while still maintaining required flow releases into Bighorn River.

  Trinity 4TL would have a capacity of 111 MW and ranked 9th for cost per MW. Trinity 4TL received multiple yellow ratings relative to operational and environmental criterion, mainly based on operational challenges at Lewiston Reservoir relative to meeting downstream flow and temperature requirements. If a detailed operations analysis shows these requirements can be met, then environmental issues may not be as challenging to overcome.

Not shown in the table, but some important considerations for selecting options to move forward are the existence of an operational ancillary services market, availability for renewable energy integration, available high voltage transmission capacity and grid impacts, demand for power in the region, available pump-back power, access, distance from the load centers and constructability (including challenges associated with tapping into an existing reservoir). The Trinity site is in northwest California, which has an emerging market for ancillary services, relative to Yellowtail, Pathfinder, and Seminoe sites in Montana and Wyoming, where there is no developed ancillary services market at this time. Montana and Wyoming, particularly, have opportunities for development of wind power, which can integrate into a pump-generation project, and then likely spur the development of an ancillary services market.

This analysis estimates transmission costs to the closest substation and does not evaluate further transmission or necessary upgrades to the power grid. For example, there are known transmission capacity limitations at the Yellowtail site, which would need to be addressed in order to use the power generated by the options. Related to transmission capacity, it is also important to assess customer demands and whether there is a need for some of these large capacity options. The Yellowtail Options 5A and 5B both have energy storage of approximately 16,000 MWh. Energy storage for the Pathfinder and Seminoe sites range from 2,700 to 9,500 MWh and energy storage at the Trinity site ranges from 1,112 MWh for the Concept 4 option to 10,245 MWh for Trinity Option 5G2-A. Some of these large capacity options may be able to service multiple markets, which would add to the value of the pump-generation project.

6.2 Recommendations

Based on the results of this study, the project team recommends the following options for further study:

- Yellowtail 5A
- Yellowtail 5B
- Trinity 5G2-A

These options have similar environmental and regulatory challenges that will need to be addressed in future planning efforts.

Yellowtail 5A and 5B are close enough in proximity that they can be further evaluated as one site. The project team recommends that Reclamation consider evaluating Yellowtail 5A and 5B during the Phase 2 evaluation, with several caveats for consideration. Reclamation should understand transmission limitations and potential impacts to the grid. The scope of this study considers transmission to the closest substation and does not include grid impacts. Further investigation of transmission capacity could also indicate whether or not there are customer needs for all the potential power generated. The Yellowtail 5A and 5B could produce up to 16,600 MWh, which could be more than the regional demand. A second caveat is that the proposed new reservoir sites are on tribal holdings. Reclamation should consider the existing relationship with the Crow Tribe and whether they could pursue a partnership with the tribe or compensate the tribe for the land. Either path would likely lead to higher project costs. The Yellowtail options are almost $1 million/MW less than the next closest options in terms of costs; therefore, additional tribal coordination costs may not change the overall cost ranking of the options.

The project team also recommends that the Trinity Option 5G2-A be considered for additional studies. This cost per MW for this option is estimated to be $1.84 million/MW, which is considered near the range as a feasible pump-generation project. This proposed new reservoir is at the upstream end of the existing Trinity Reservoir and would likely have fewer issues TRRP and CVP operations. California also has a more developed ancillary services market, which would add to the economic benefits of the project and make it more economically viable based on costs and benefits. California also has more challenging environmental issues that could prevent construction of new reservoir. A detailed operations analysis of Trinity site could also help inform Reclamation of the potential feasibility of Trinity Option 4TL, which would avoid construction of a new reservoir and use the existing forebay and afterbay.

In addition to the Yellowtail and Trinity options, further study of a Wyoming site would be beneficial because of the wind development potential and the need for energy storage. Both the Seminoe 5C and 5A2 sites offer the most development potential and could be further evaluated in the Phase 2 Study effort.

Reclamation should continue to evaluate the market demand for power in these sites and their other service areas. Preliminary research in this Phase 1 evaluation has shown that local utilities are in need of increased generation to meet growing demands. Furthermore, utilities are also in need of bulk storage to integrate wind and other renewable resources into the utility grid. Transmission capacity and infrastructure is also an important factor in assessing site viability to determine if power produced in remote rural areas can be delivered to the urban load centers. These topics will be further investigated in the Phase 2 evaluation.

Reclamation should also assess whether there are other existing forebays and afterbays in their entire service area that may have pump-generation potential or another area where a new reservoir could serve pump-generation and other needs. Alternative sites may arise that are technically acceptable and perhaps have larger demand for power and a pump-generation project. This Phase 1 evaluation has established a process to identify and screen potential options for pump-generation that could be applied to other areas.

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Table 6-2. Option Evaluation and Comparison

Site	Yellowtail	Yellowtail	Yellowtail	Yellowtail	Pathfinder	Pathfinder	Seminoe	Seminoe	Seminoe	Seminoe	Trinity	Trinity	Trinity	Trinity
Option	**5A**	**5B**	**4YA-1**	**4YA-2**	**5A1**	**5D**	**5A1**	**5A2**	**5C**	**5D1**	**5A-B**	**5F**	**5G2-A**	**4TL**
Upper Reservoir	New Reservoir 5A	New Reservoir 5B	Bighorn Lake	Bighorn Lake	New Reservoir 5A1	New Reservoir 5D	New Reservoir 5A1	New Reservoir 5A2	New Reservoir 5C	New Reservoir 5D1	New Reservoir 5A-B	New Reservoir 5F	New Reservoir 5G2-A	Trinity
Lower Reservoir	Bighorn Lake	Bighorn Lake	Yellowtail Afterbay	Yellowtail Afterbay	Pathfinder	Alcova	Kortes	Seminoe	Seminoe	Kortes	Trinity	Lewiston	Trinity	Lewiston
Technical Screening														
Upper Reservoir Usable Vol (acre-ft)	12,081	13,509	2,875	1,413	5,297	12,950	3,068	10,119	7,145	2,689	13,697	3,109	15,022	3,154
Lower Reservoir Usable Vol (acre-ft)	336,103	336,103	2,875	1,413	985,102	30,603	3,073	985,603	985,603	3,073	1,859,688	3,154	1,859,688	3,154
Approx. Static Head (ft) (<2650 ft)	1,562	1,352	444	431	1,232	621	1,025	869	909	1,126	635	2,248	775	401
Assumed Usable Storage Volume	12,081	13,509	2,875	1,413	5,297	12,950	3,068	10,119	7,145	2,689	13,697	3,154	15,022	3,154
Assumed Hours of Storage	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Resulting Installed Capacity (MW)	1,660	1,607	112	54	575	708	277	773	572	266	765	615	1,024	111
Energy Storage (MWh)	16,601	16,067	1,123	536	5,745	7,082	2,767	7734	5,715	2,664	7,654	6,151	10,245	1,112
Estimated Dam Volume (CY)	7,734,313	6,499,188	NA	NA	3,671,836	5,716,670	4,688,429	9,756,673	8,430,094	1,899,238	7,837,254	2,990,932	4,025,634	NA
Maximum Dam Height (ft) (<400 ft)	298	261	NA	NA	231	269	297	397	336	216	377	278	139	NA
L/H Ratio (Guideline)	5 (<12)	6 (<12)	6 (<7)	6 (<7)	9 (<12)	14 (<10)	7 (<12)	10 (<12)	7 (<12)	5 (<12)	15 (<12)	10 (<12)	9 (<12)	11 (<7)
Typical Operating Range of Pumps (70-100%)	86%	85%	78%	82%	84%	79%	88%	75%	80%	85%	72%	98%	71%	70%
Cost Opinions														
Construction Cost (million)	$2,081	$2,141	$233	$133	$1,2501	$1,696	$860	$1,765	$1,235	$664	$1,862	$1,223	$1,885	$256
$/MW Installed Capacity (million)	$1.25	$1.33	$2.07	$2.48	$2.18	$2.39	$3.11	$2.28	$2.16	$2.49	$2.43	$1.99	$1.84	$2.31
Cost Ranking based on $/MW	1	2	5	12	7	10	14	8	6	13	11	4	3	9
Operations Criteria														
Reservoir Elevation/Storage Requirements														
Minimum Flow Release Requirements														
Water Quality/Temperature Requirements														
System Reoperation														
Environmental, Regulatory, and Institutional Criteria														
Fisheries Issues														
Special Status Species/Critical Habitat														
Recreation														
Cultural and Historic Resources														
Native American Resources														
Land Use/Regulatory Designation														
Construction Impacts														
Stakeholders Issues														

Qualitative Criteria Rating Scale:
“Green” indicates effects can likely be coordinated, avoided, or mitigated
“Yellow” indicates effects might pose challenges, but is not fatal flaw at this point in the analysis
“Red” indicates effects are a potential fatal flaw to the development of alternative

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Chapter 7
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Appendix A
AACE Class 1 through 5 Cost Estimate Classifications

Table B-1. AACE Class 1 through 5 Cost Estimate Classifications

Estimate Class	Class 5	Class 4	Class 3	Class 2	Class 1
LEVEL OF PROJECT DEFINITION Expressed as a % of complete definition	0% to 2%	1% to 15%	10% to 40%	30% to 70%	50% to 100%
END USAGE Typical purpose of estimate	Concept Screening	Study or Feasibility	Budget Authorization or Control	Control or Bid/Tender	Check Estimate or Bid/Tender
METHODOLOGY Typical estimating method	Capacity Factored, Parametric Models, Judgment, or Analogy	Equipment Factored or Parametric Models	Semi-Detailed Unit Costs with Assembly Level Line Items	Detailed Unit Cost with Forced Detailed Take-Off	Detailed Unit Cost with Detailed Take-Off
EXPECTED ACCURACY RANGE Typical variation in low and high ranges (a)	L: -20% to -50% H: +30% to +100%	L: -15% to -30% H: +20% to +50%	L: -10% to -20% H: +10% to +30%	L: -5% to -15% H: +5% to +20%	L: -3% to -10% H: +3% to +15%
PREPARATION EFFORT Typical degree of effort relative to least cost index of 1 (b)	1	2 to 4	3 to 10	4 to 20	5 to 100
REFINED CLASS DEFNITION	Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systemic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than 1 hour to prepare. Often, little more than proposed plant type, location, and capacity are known at the time of estimate preparation.	Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams (PFDs) for main process systems, and preliminary engineered process and utility equipment lists.	Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists.	Class 2 estimates are generally prepared to form a detailed control baseline against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the “bid” estimate to establish contract value. Typically, engineering is from 30% to 70% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, piping and instrument diagrams, heat and material balances, final plot plan, final layout drawings, complete engineered process and utility equipment lists, single line diagrams for electrical, electrical equipment and motor schedules, vendor quotations, detailed project execution plans, resourcing and work force plans, etc.	Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor’s bid estimate, or to evaluate/dispute claims. Typically, engineering is from 50% to 100% complete, and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans.
END USAGE DEFINED	Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long-range capital planning, etc.	Class 4 estimates are prepared for a number of purposes, such as but not limited to detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.	Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project phase “control estimates” against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate may be the last estimate required and could well form the only basis for cost/schedule control.	Class 2 estimates are typically prepared as the detailed control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program.	Class 1 estimates are typically prepared to form a current control estimate to be used as the final control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution.
ESTIMATING METHODS USED	Class 5 estimates virtually always use stochastic estimating methods such as cost/capacity curves and factors, scale of operations factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, and other parametric and modeling techniques.	Class 4 estimates virtually always use stochastic estimating methods such as equipment factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques.	Class 3 estimates usually involve more deterministic estimating methods than stochastic methods. They usually involve a high degree of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less-significant areas of the project.	Class 2 estimates always involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve tens of thousands of unit cost line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed to use as line items in the estimate instead of relying on factoring methods.	Class 1 estimates involve the highest degree of deterministic estimating methods, and require a great amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities.
EXPECTED ACCURACY RANGE	Typical accuracy ranges for Class 5 estimates are -20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 2 estimates are -5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 1 estimates are -3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.
EFFORT TO PREPARE (for US$20MM project)	As little as 1 hour or less to perhaps more than 200 hours, depending on the project and the estimating methodology used.	Typically, as little as 20 hours or less to perhaps more than 300 hours, depending on the project and the estimating methodology used.	Typically, as little as 150 hours or less to perhaps more than 1,500 hours, depending on the project and the estimating methodology used.	Typically, as little as 300 hours or less to perhaps more than 3,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.	Class 1 estimates require the most effort to create, and as such are generally developed for only selected areas of the project, or for bidding purposes. A complete Class 1 estimate may involve as little as 600 hours or less, to perhaps more than 6,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.
ANSI Standard Reference Z94.2-1969 name; Alternate Estimate Names, Terms, Expressions, Synonyms	Order of magnitude estimate, ratio, ballpark, blue sky, seat-of-pants, ROM, idea study, prospect estimate, concession license estimate, guesstimate, rule-of-thumb.	Budget estimate, screening, top-down, feasibility, authorization, factored, pre-design, pre-study.	Budget estimate, budget, scope, sanction, semi-detailed, authorization, preliminary control, concept study, development, basic engineering phase estimate, target estimate.	Definitive estimate, detailed control, forced detail, execution phase, master control, engineering, bid, tender, change order estimate.	Definitive estimate, full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate.

Notes: (a) The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.
(b) If the range index value of “1” represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

Source: AACE International Recommended Practice No. 18R-197, February 2, 2005.