HYDROPOWER FEASIBILITY STUDY

COONEY, PAINTED ROCKS, AND TONGUE RIVER DAMS

PHASE II REPORT

MONTANA DEPARTMENT OF NATURAL RESOURCES & CONSERVATION

EXECUTIVE SUMMARY

The Montana Department of Natural Resources & Conservation (DNRC) contracted Kleinschmidt Associates (Kleinschmidt) to undertake a preliminary hydropower feasibility study of the hydroelectric generating potential at three state owned dams: Painted Rocks, Cooney, and Tongue River. Pursuant to DNRC's direction, Kleinschmidt conducted the study in two phases.

The Phase I effort was a conceptual level assessment of hydroelectric generation development feasibility at the three sites. The assessment screened various development options at each site - initially identifying potential "red flags" that would preclude development from an economic, regulatory or environmental standpoint. Potential red flag items identified in Phase I included:

- Transmission Line Construction Costs (All sites)
- FERC Part 12 Dam Safety Compliance (All sites)
- Painted Rocks Dam Headpond Fluctuation
- Use of Existing Tongue River Dam Infrastructure

Phase I analysis included an initial determination of project generating capacity, estimated annual generation and project development costs for various configurations without site specific red flag issues. Kleinschmidt used available flow and reservoir level to determine potential installed capacity and estimated annual generation. An estimated development cost was derived using $Cost/KW of installed capacity. Kleinschmidt based this cost derivation on data from recently constructed projects of similar size and complexity. The resulting estimated generation values and development cost allowed ranking of the various development options' viability based on a simple payback calculation. Upon review of the Phase I study results, the DNRC identified preferred development options at each dam site, which Kleinschmidt subsequently studied in more detail as part of Phase II analysis.

For Phase II, Kleinschmidt prepared detailed conceptual project layouts and opinions of probable cost based on selected site configurations and standardized construction and equipment costs. The detailed cost opinion also included indirect cost allowances such as contractor mobilization, engineering and licensing costs, contingencies and owner administration costs. Kleinschmidt derived the estimated annual project revenue using the Qualifying Facility (QF) tariff schedule published by Idaho Public Utilities Commission (IPUC (August 2011)). After consultation with DNRC, Kleinschmidt used this rate data because blended, escalated future power purchase rate data was not available from the Montana Public Service Commission (MPSC). The IPUC's published power rate schedule extends to 2026. Comparison of current rates noted by the MPSC to those noted in the IPUC report indicated that the Idaho rates were a reasonable approximation for the future power purchase rates for these projects. Kleinschmidt determined future power rates for 2026-2044 by extrapolating the published rates by the average percentage increase between the last several years of published data. Using this data, purchased power rates were assumed to begin at $58.39/MWH and increase over the 30 year debt service period to approximately $168/MWH.

The benefit cost ratio for each development was derived using the cost opinion for each option, the estimated average annual generation, and the power purchase rates obtained for each location[1]. The economic analysis assumed 100% project financing[2] with a 30-year debt service period. The analysis assumed that the projects would come on line in 2015. Because of the debt service length, the analysis included a capital cost allowance of $250,000 in year 20 for major equipment refurbishment (*e.g.*, generator rewind and/or turbine overhaul). The analysis also assumed $100,000/ year operation and maintenance (O&M) costs with a 2% annual escalation rate. The analysis did not include added value for any potential peaking power, capacity charges or other ancillary benefits credits; each of which could enhance project economics and may warrant further consideration by DNRC.

TABLE 1. SUMMARY OF PROJECT COSTS

PROJECT	OPTION	NO. OF UNITS	PROPOSED INSTALLED CAPACITY (KW)	ESTIMATED ANNUAL GENERATION (MWH)	ESTIMATED PROJECT DEVELOPMENT COST ($)	BENEFIT/COST RATIO
Cooney	1	1	1100	2955	5,349,519	0.61
	2	1	1340	3297	6,596,281	0.59
Painted Rocks	1	1	2680	6513	18,932,833	0.48
	2	2	4280	8207	20,169,503	0.59
Tongue River	1	1	2160	6004	10,124,937	0.77
	2	2	2160	7344	10,765,786	0.9

Using the assumptions noted, Phase II study results indicated that none of the projects has a benefit cost ratio greater than 1. The Cooney and Painted Rocks Dam developments have benefit cost ratios substantially less than 1 and do not result in a positive cash flow over the debt service. Cooney Option 1 (Figure 2) and Painted Rocks Option 2 (Figure 5) turn to a positive cash flow in year 30. At the Cooney Development, the principal cause for this site being uneconomic is the low annual power generation. At the Painted Rocks site, the cost to construct the approximately 15 miles transmission line results in the project revenues not able to support the total development cost.

[1] To consider a project economically viable, ideally the cost benefit ratio is 1 or greater.
[2] 4% interest rate assumption

Of the three sites, Tongue River has a benefit cost ratio of 0.9, indicating marginal feasibility. With a more detailed design to reduce project contingencies, actual cost data from equipment suppliers and actual data regarding revenue, this project could become viable. Further, the estimated generation is based on the average reservoir level for the period 1999-2008. Review of the actual reservoir level data for the period noted a higher elevation on the Tongue River reservoir for the years 2009 and 2011. This would result in the annual generation being greater than the estimated average value. Conversely, 2004 was a dry year with reservoir levels lower than the average values resulting in less generation than forecasted for the period of record. Over the period of debt service, the actual annual generation will vary due to the typical hydrologic variation. Variations of up to 20-25% are typical.

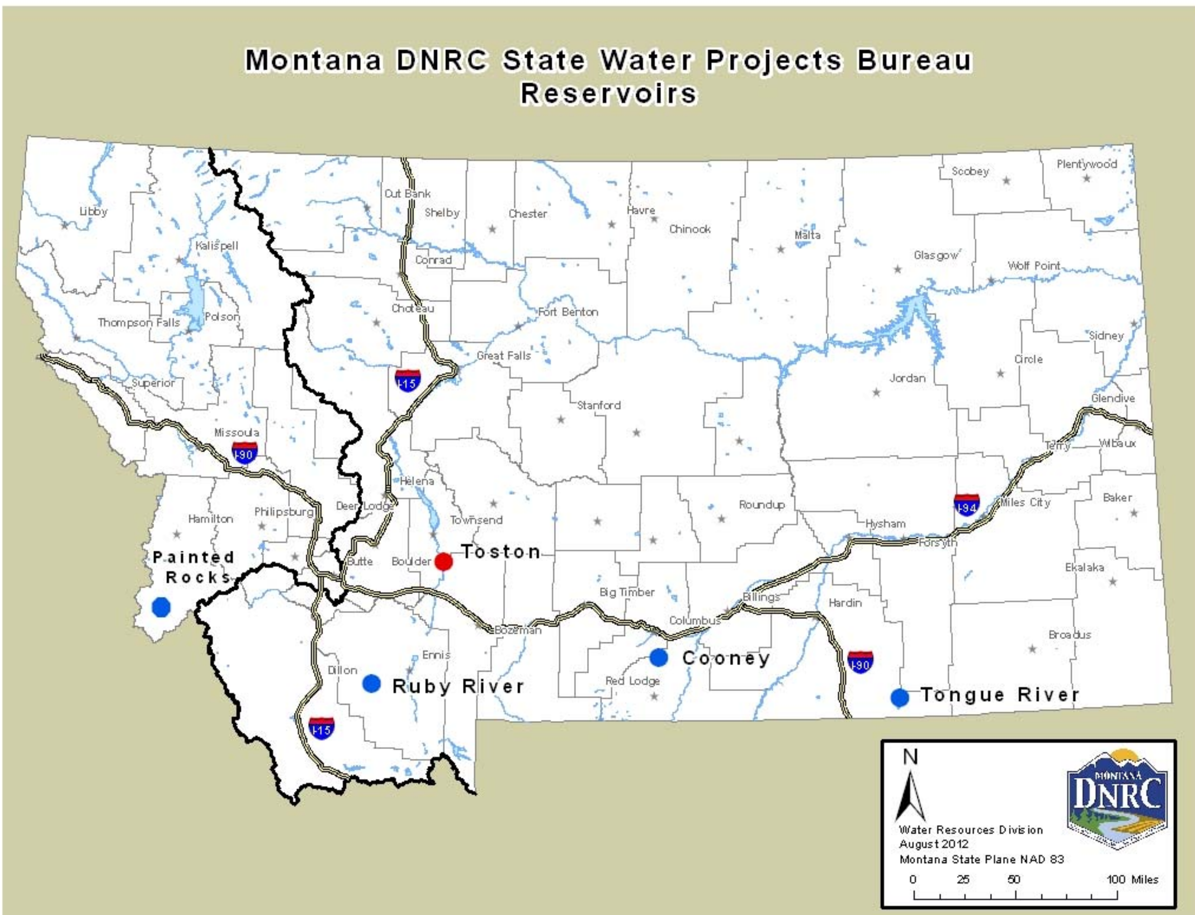


FIGURE 2. PROJECTED REVENUE V. PROJECT COST – COONEY OPTION 1

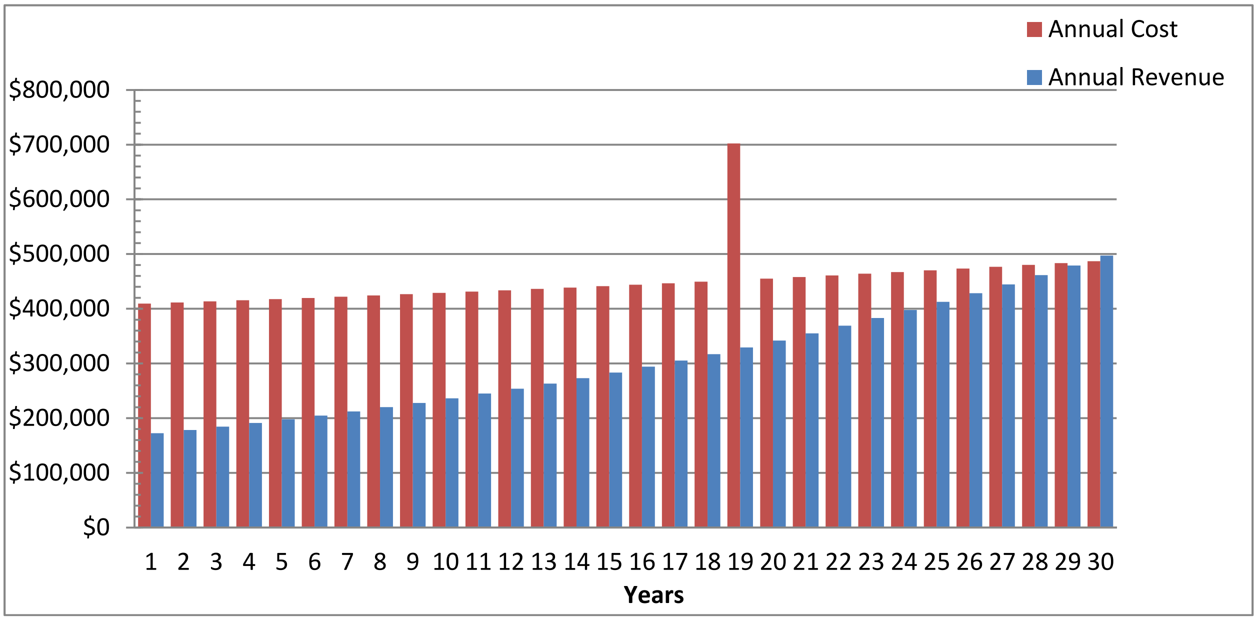


FIGURE 3. PROJECTED REVENUE V. PROJECT COST – COONEY OPTION 2

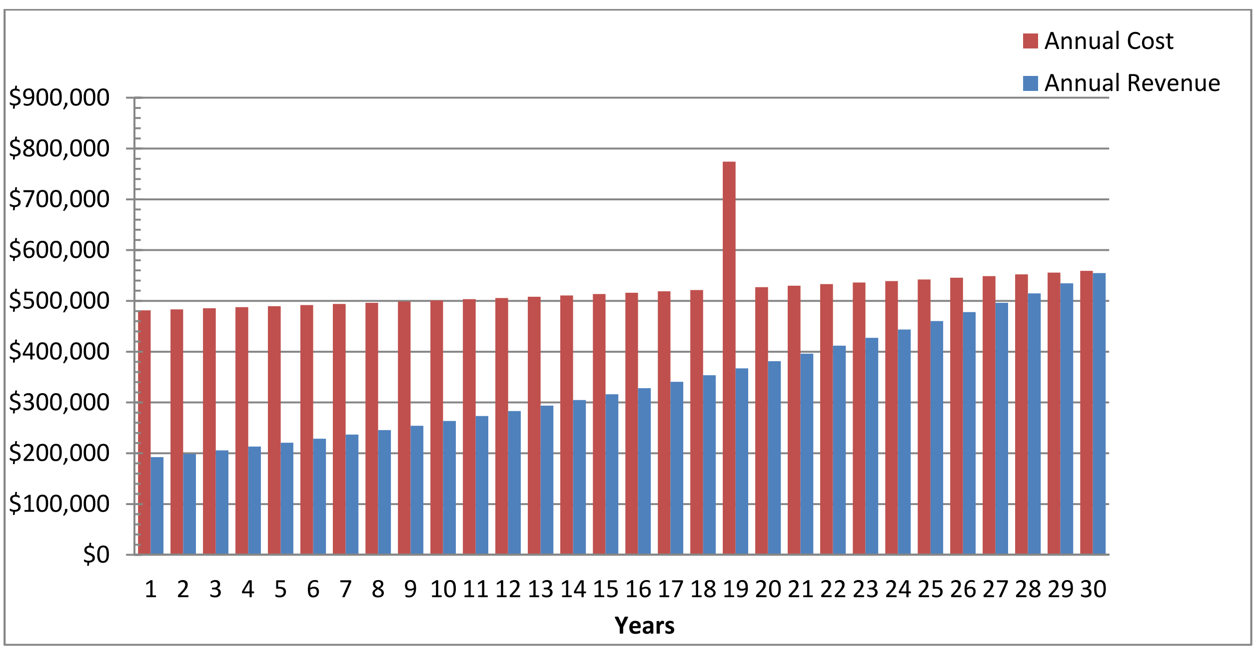


FIGURE 4. PROJECTED REVENUE V. PROJECT COST – PAINTED ROCKS OPTION 1

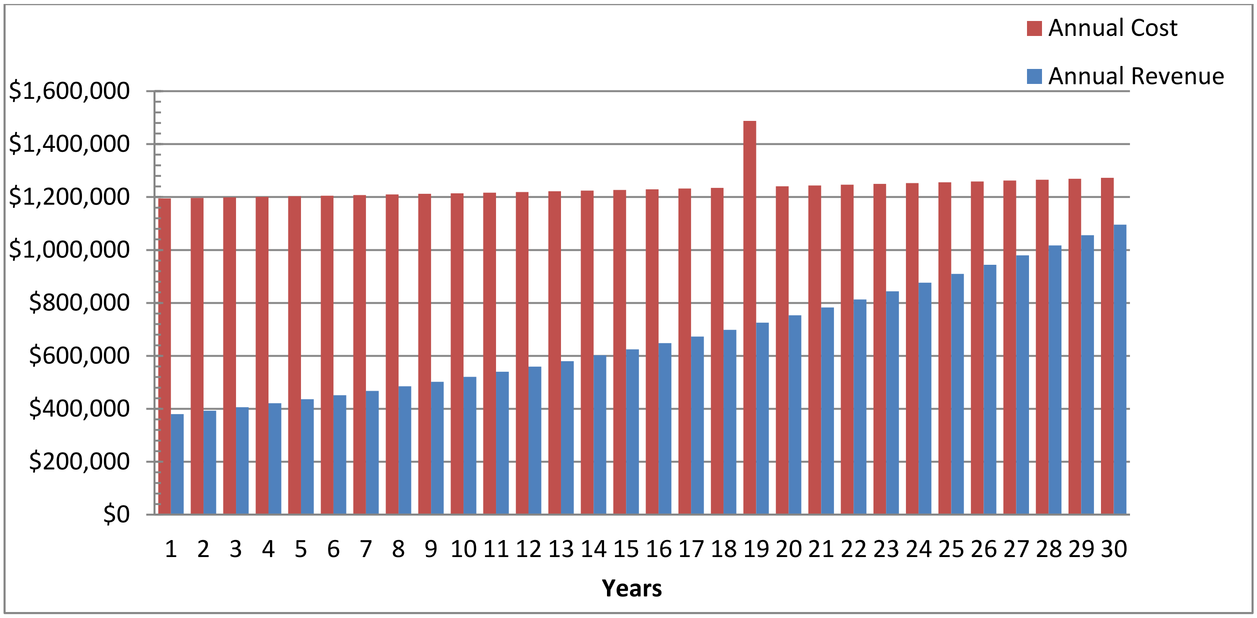


FIGURE 5. PROJECTED REVENUE V. PROJECT COST – PAINTED ROCKS OPTION 2

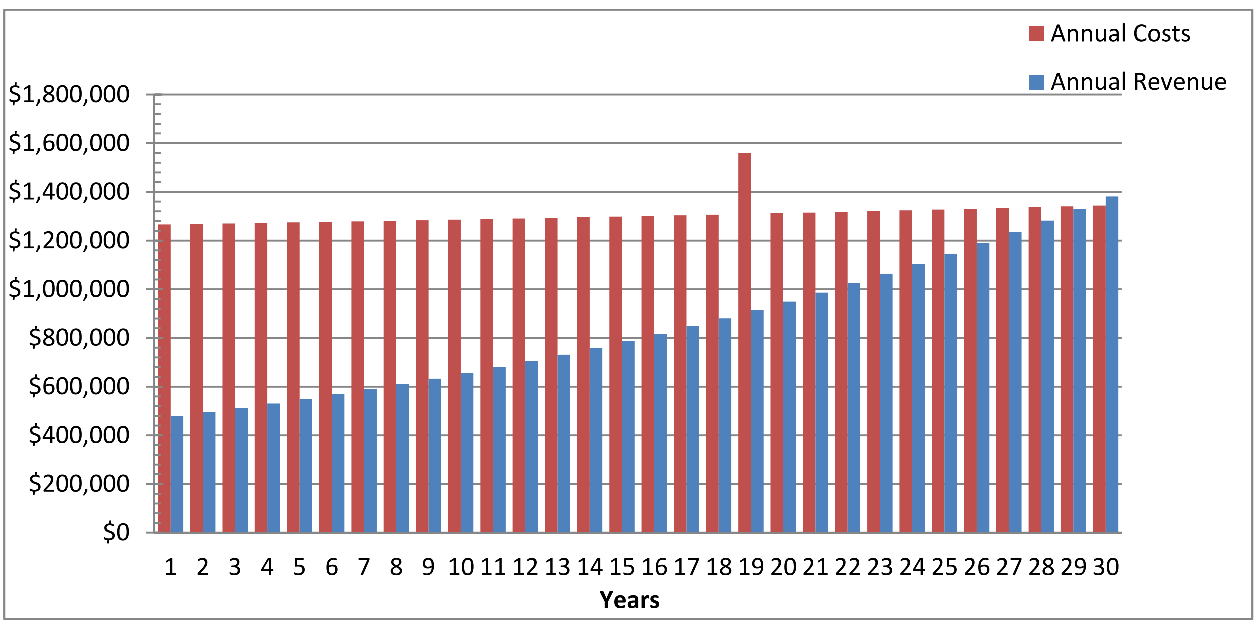


FIGURE 6. PROJECTED REVENUE V. PROJECT COST – TONGUE RIVER OPTION 1

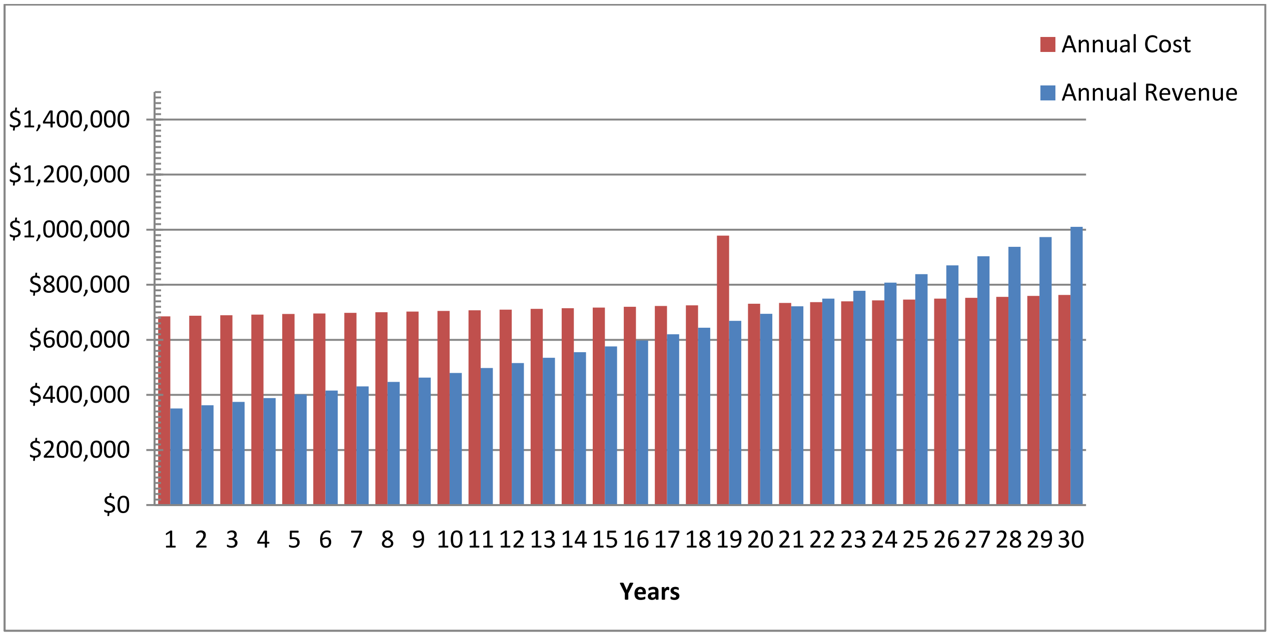
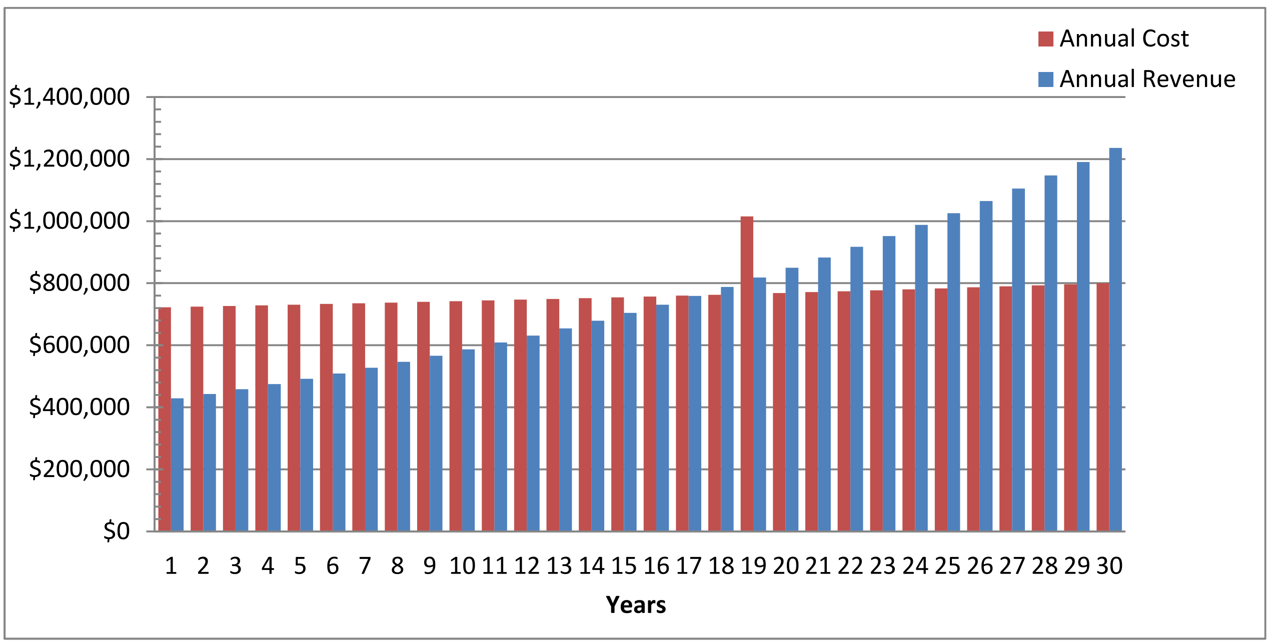


FIGURE 7. PROJECTED REVENUE V. PROJECT COST – TONGUE RIVER OPTION 2



1. EXECUTIVE SUMMARY

The addition of hydropower generation capacity at Ruby Dam is feasible from a technical perspective. No fatal flaws were identified in this reconnaissance-level investigation, which preclude the installation and operation of a hydropower plant at the reservoir. Two conceptual layouts are provided using Kaplan and Francis turbines. The preferred conceptual layout includes two Kaplan turbines with operational capacities of 0.77 MW and 2.71 MW respectively, with a total 3.48 MW production capacity. Using the two different sizes will optimize power generation potential based upon the historical hydrologic conditions at the reservoir, existing and forecasted power revenues, and an upgrade in electrical distribution line capacity in a cost-effective manner. In a similar context, an alternative layout would use one 0.54 MW and two 1.46 MW Francis turbines, with a total 3.46 MW capacity. The economic analyses include powerhouse costs, potential revenue from the sale of electricity, and debt finance options to determine the annual rate of return for average hydrologic scenarios. The two dominant and viable alternatives are:

Kaplan Turbine Option	3.48 MW hydropower plant	4.97% rate of return
Francis Turbine Option	3.46 MW hydropower plant	2.88% rate of return

The economic rate of return is defined as the interest rate that will discount all cash flows to a total present worth equal to the initial required investment. It is also used as an empirical method to compare alternatives (Robinson 1987).

URS also performed an economic analysis based upon a range of hydrologic conditions to provide a comparative analysis of costs, revenues, and potential risk in the installation of a hydropower facility at Ruby Reservoir. Capital costs, revenues from hydropower generation and renewable energy credits, and operational cost were included in the analysis. The benefit/cost ratio for a 3.48 MW hydropower plant using Kaplan Turbines with a maximum rated capacity of 450 cubic feet per second over a 30 year term and 4% discount rate under average hydrologic conditions was 1.10. However, the net yearly annual cash flow is negative until the 25-year debt is retired for all hydrologic conditions except during wet periods, which presents an unattractive financial condition under the present fixed-rate revenue structure.