2016-2030 Hydro Asset Strategy
Least Cost Planning and Calculation of Net Present Value

The strategy takes a least-cost approach to determining the timing of future equipment replacement decisions. The approach is consistent with the Regional Power Act, BPA's asset management policy, and BPA's Climate Change Action Plan.

Costs Evaluated in the Strategy

1. **Equipment Replacement Cost –** Forecasted replacement costs were developed for 50 equipment types (turbine runner, transformer, etc.) by the Corps' Hydroelectric Design Center, the organization responsible for developing government estimates for procurement of Corps hydroelectric equipment. For each equipment type, cost estimates include a fixed cost component, which is the same for all equipment of that type, and a variable cost component, which is dependent on parameters related to the size and complexity of the equipment, i.e., shaft diameter, MVA rating, etc.

2. **Incremental Equipment Failure Cost –** When equipment fails, costs to repair or replace it are typically incrementally higher due to collateral damage and to planning, procurement and scheduling inefficiencies. Incremental failure costs are specific to each equipment type, expressed as a percentage of replacement cost when done on a planned basis.

3. **Replacement Power Cost –** For the asset strategy, Federal Hydro Projects used hydro regulation studies to determine the amount of generation produced by each plant on the system using results from the most recent 5-year availability forecast. Generation amounts were calculated for HLH and LLH periods by month for 80 water years. Next, hydro regulation studies were run at lower levels of unit availability to determine the amount of generation that would be produced if the plants were less reliable. The difference between modeling runs produces the incremental generation from an increment of plant availability. For the strategy, the incremental generation produced by the "least used" unit (marginal unit) was calculated for each plant on the system. This is the amount of generation that is deemed to be at risk in the event of equipment failure. Although a distinct possibility, particularly for plants with many generating units or low reliability, no consideration was given to multiple and simultaneous equipment failures that would take more than one unit out of service and have increasingly higher lost generation consequences.

   When equipment fails and takes a generating unit out of service, repairing and replacing the equipment typically takes longer than if work is done on a proactive, planned basis. For instance, a transformer can take three or more years to procure and, absent having a spare available, a failure would take a generating unit (or multiple units) out of service for three years or longer. Replacing a transformer on a planned basis typically requires an outage of three months or less. So, the incremental outage duration for a failed transformer can be 2.75 years if no spare is available (we assumed 1.5 years in the strategy). Other equipment types have much shorter incremental outage durations.

The annual generation at risk for the marginal unit at each plant is then multiplied by the expected additional outage in years for each equipment type to determine the amount of lost generation if that equipment fails. The lost generation is valued at BPA's rate case long-term forward price forecast to determine a replacement power cost (or lost secondary market opportunity) for the equipment failure.

4. **CO2 Cost** – BPA's Climate Change Action Plan requires hydro investment decisions to include greenhouse gas avoidance benefits in asset planning analyses and business cases for proposed capital and major expense sub-agreements. BPA's common planning assumptions for avoided CO2 emissions results in a levelized cost of $35.42 per ton. This cost is multiplied by the CO2 emissions generated by a combined cycle natural gas plant (0.43 tons per MWh) – the resource that would be used to offset losses in hydro generation – to determine the avoided CO2 cost for maintaining hydro plant reliability.

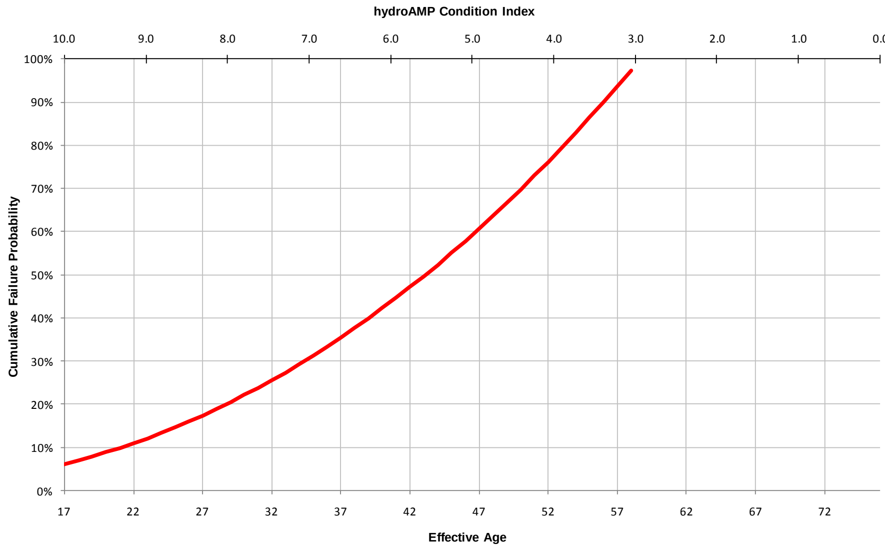
For the strategy analysis, only equipment replacement costs are deterministic. Other costs are probability-based, derived from information about equipment condition that is correlated to a likelihood of failure.

Equipment Condition and its Relationship to Risk

The strategy analysis uses hydroAMP to assess condition of power train and some other hydro equipment. Developed by the Corps, Reclamation, BPA and Hydro Quebec, hydroAMP uses a set of condition indicators describing operational performance, maintenance history, physical inspection, age, and specialized testing results to derive a condition index for equipment. The condition index scale ranges from zero (Poor condition) to 10 (Good condition). For equipment not covered by hydroAMP, a simplified condition assessment tool was built based on the hydroAMP methodology.

A regression analysis was performed on the hydroAMP database to establish a correlation between a condition index and equipment "effective age". The results were then used to map the hydroAMP condition index and effective age to a survivor curve for that equipment. Survivor curves are derived from industry data and show the relationship between equipment age and the percentage of the equipment population that has failed or been retired. Mapping the hydroAMP results to the survivor curve yields a failure probability for equipment with a certain condition index and effective age. A generator winding curve is shown below.

Generator Winding Curve



Survivor curves were not available for all types of equipment. For those cases, curves were developed based on professional judgment.

Risk is a function of the probability of failure as condition degrades over time. For the strategy, four types of risk were calculated in incremental time steps:

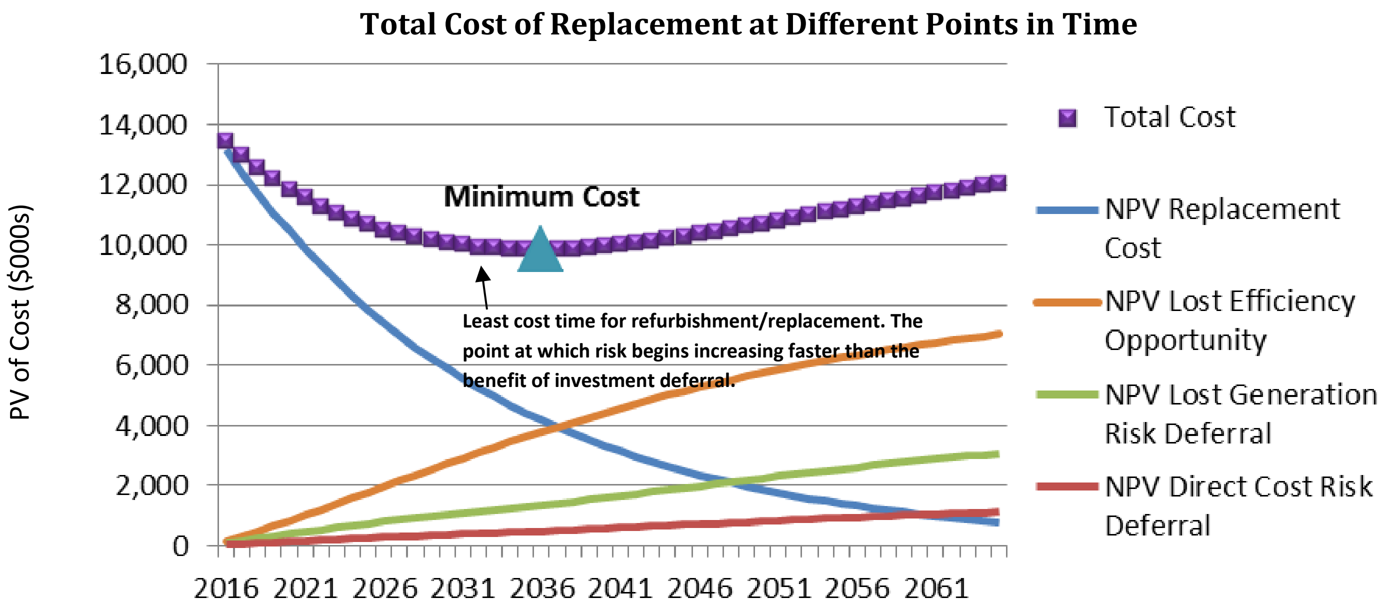
1. **Safety Risk,** where equipment failure has a relatively high probability of causing permanent disabilities or multiple fatalities;
2. **Environmental Risk,** where equipment failure has a relatively high probability of causing detrimental or catastrophic environmental impacts;
3. **Direct Cost Risk (DCR)**, which is the Incremental Equipment Failure Cost identified above multiplied by the incremental probability of failure over time; and,
4. **Lost Generation Risk (LGR)**, which is the sum of Replacement Power Cost and CO2 Cost multiplied by the incremental probability of failure.

The sum of Direct Cost Risk and Lost Generation Risk are hereafter described as financial risk.

Replacement of some equipment types result in efficiency improvements, meaning more power can be generated with the same amount of water. Efficiency improvements are possible due to either technology improvements since the original equipment was designed or because the efficiency of the original equipment has degraded with age. For the strategy, only turbine efficiency improvements are considered. The potential efficiency improvement for each turbine is calculated from its age and assumed annual efficiency degradation as well as its potential for technology improvements given the varying hydraulic characteristics at each plant. For the purposes of identifying the optimum timing for equipment replacement, a Lost Efficiency Opportunity (LEO) cost is forecast over time for each turbine to recognize the foregone efficiency improvement benefit that would be realized from turbine replacement. The lost efficiency opportunity grows over time as the equipment ages and efficiency degrades.

Optimum Timing for Equipment Replacement

To determine the optimum timing for replacement, each equipment component is evaluated in yearly time steps over 15 years. In each year, the present value of accumulated financial risk cost is added to the present value cost of replacing the equipment in that year. The sum of these present value costs is the Total Cost related to a decision to delay equipment replacement until that year. This algorithm is described graphically below.



The optimum time to plan on equipment replacement is at the low point (cost minimum) of the Total Cost curve. The cost minimum is the point in time at which the sum of financial risk costs and potential lost efficiency opportunity begin growing faster than the benefit of deferring the investment. Up until that time the value of investment deferral is greater than the expected increase in financial risk and lost efficiency opportunity costs, so it makes financial sense to continue deferring equipment replacement. This objective function is applied to each of the 5,500 equipment components included in the strategy to derive an investment plan.

Running the model without funding constraints generates the "least-cost plan". Under this scenario, equipment replacements for projects that are already underway are funded as planned. Potential new investments are then selected for refurbishment/replacement if they meet either of the following criteria:

- First, if condition places the equipment into a safety or environmental high risk category; or,
- Secondly, if financial risk costs are increasing faster than the investment deferral benefit, i.e., the equipment has reached the cost minimum.

The model can also be run to limit annual funding availability to any level desired. For these cases, once an annual funding limitation is reached, investment in equipment in which financial risk is increasing the least is deferred until the following year, where it is then re-evaluated using the same prioritization logic.

As funding levels are increasingly constrained, more new investments are deferred past their cost minimum which causes the Total Cost to increase accordingly.

Calculation of Net Present Value

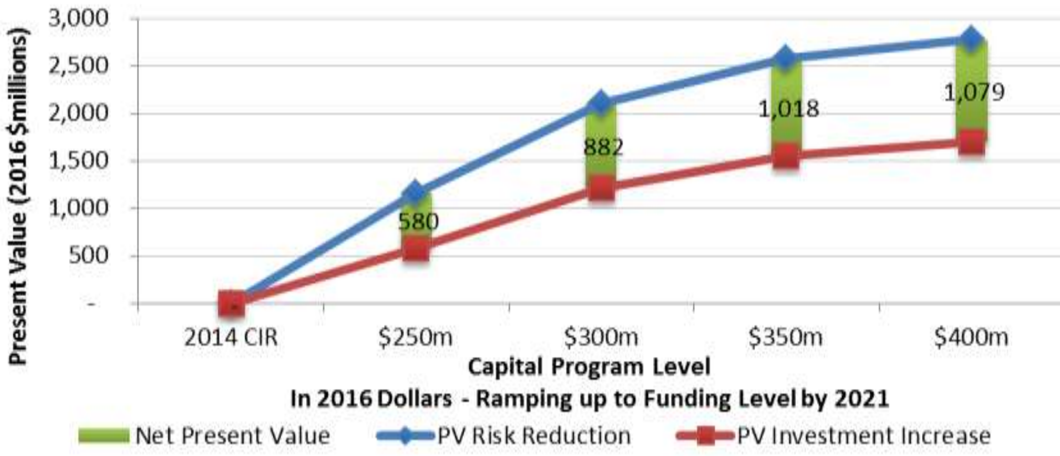
The Total Cost for the system increases when a funding constraint causes new investments to be pushed out past the cost minima. For the 2016 IPR process, the Recommended $300 million plan was somewhat more costly than the least-cost plan (we estimated a net present value of -$279 million, i.e., an increase in present value of system cost of $279 million), but it yielded a relatively stable program level during the constrained funding period and identified a resource capability that could be sustained into the future. The plan results were also robust across sensitivities run on planning assumptions.

2016-2030 Hydro Asset Strategy Planning Assumptions

Assumption	Value	Source	Comment
Discount rate	8.0 percent	BPA Generating Assets	10 percent real 6 percent real
Inflation rate	1.9 percent	BPA Finance	Average annual rate, 20-yr forecast
Forward energy price curve	20-yr, by month, HLH, LLH, flat $36 – Levelized Energy Value $25 – Capacity Value	BPA Power Services Resource Program	Includes spot prices and a component for long-term firm capacity consistent with rate case demand rate.
Equipment cost	Varies by equipment type	FCRPS hydro program	Based on industry cost data
Real cost escalation	0 percent	BPA Finance	Global Insight
Failure curves	Varies by equipment type	BPA Generating Assets	Based on industry data for certain equipment
Outage duration for LGR	Varies by equipment type	FCRPS hydro program	Based on industry experience
Environment and safety	Risk	BPA Generating Assets	Treats all high risk items as “must do”
Value of avoided CO2	$35/ton	BPA Corporate Strategy	Based on Presidential Directive
Alternative resource for hydro lost generation	Natural gas-fired Combined-Cycle Combustion Turbine	BPA Agency Asset Management	0.48 tons of CO2 per MWh of generation

For the capital investment level scenario analyses, the 2014 CIR plan (approximately a $200 million per year investment level) was used for the base case. The net present value of all scenarios was measured relative to this plan. The net present value of each capital scenario is shown to increase with increased capital investment, but returns begin to diminish quickly after a $300 million investment level.

Results of the scenario analyses are summarized in the graphs below.



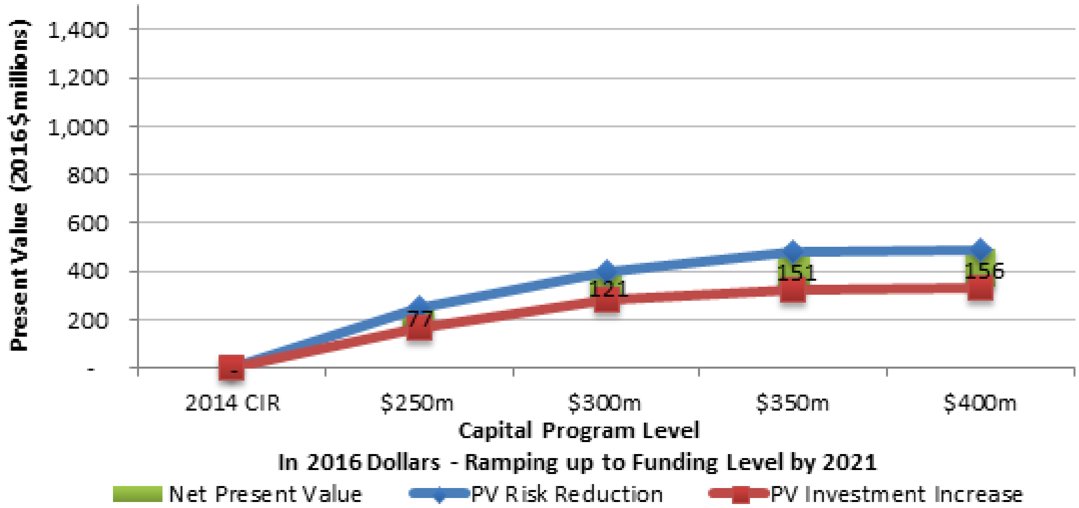
The following table details the composition of the net present value by risk reduction benefits and investment costs. Lost Generation Risk (LGR), Direct Cost Risk (DCR) and Lost Efficiency Opportunity (LEO) reduction benefits shown below are an aggregated total of the risk mitigation calculated from the investment plan identified in the strategy.

50-Year Present Value (8% Discount Rate)

Investment Level	PV LGR Reduction	PV DCR Reduction	PV LEO Reduction	PV of Total Risk and Lost Efficiency Reduction	PV Investment Increase	Net Present Value
$250m	766	287	108	1,161	581	580
$300m	1,264	565	272	2,101	1,218	882
$350m	1,504	694	374	2,571	1,554	1,018
$400m	1,624	743	411	2,778	1,699	1,079

As the investment level increases, fewer pieces of equipment are deferred passed their optimal replacement dates and the net present value approaches that of an unconstrained investment scenario as more risk is mitigated.

NPV of Investment - $20 Real Levelized Energy Price, No Capacity or avoided CO2 value



50-Year Present Value (8% Discount Rate)

With a low long term energy price and no value attributed to capacity or avoided CO2 emissions, the benefits of higher program levels are significantly reduced. However, the modeling still identifies a positive net present value in higher investment levels, at least in the near term. This is reflective of the backlog of reinvestment need at high risk facilities where much of the powertrain equipment has exceeded design life and is in poor condition. It should be noted that by 2025, the modeling no longer identifies investments up to full budget constraint at a $300 million program, resulting in an average annual investment level of about $260 million (in 2016 dollars) per year through 2030.

50-Year Present Value (8% Discount Rate)

Investment Level	PV LGR Reduction	PV DCR Reduction	PV LEO Reduction	PV of Total Risk and Lost Efficiency Reduction	PV Investment Increase	Net Present Value
$250m	132	107	7	247	170	77
$300m	216	175	8	399	278	121
$350m	253	214	10	476	326	151
$400m	259	220	11	489	334	156

Other Considerations

The risk analysis is based on the loss of the marginal unit at each plant, when there is a distinct possibility that failures could simultaneously take multiple units out of service. Modeling probabilities of multiple unit outages is currently under development and its impacts on the efficiency of the modeling are under evaluation.

The FCRPS is a 22,050 MW hydro system. The replacement cost for all major equipment components is estimated to exceed $750 per kW (2010 dollars), or $16.5 billion. A $200 million annual investment level is equivalent to 1.2 percent per year of the estimated total replacement cost, corresponding to an average equipment life of about 82 years. The average design life of power train equipment is 45 years, which indicates the FCRPS may be under investing in the system. A $300 million annual investment level is equivalent to 1.8 percent per year of the estimated total replacement cost or a corresponding average equipment life of about 55 years, much closer to average design life of power train equipment.

The FCRPS participates in the EUCG Hydroelectric Productivity Committee in which it benchmarks its hydro program against 15 other hydroelectric utilities worldwide. Currently, the FCRPS is investing about two-thirds of the benchmark median in terms of capital investment. The industry benchmark median for capital investment in a system the size of the FCRPS is about $320 million per year.