5.23 Power

5.23.1 Introduction

Changes to TVA's reservoir operations policy may cause changes in the cost of hydropower and non-hydropower production, and in power system reliability. To assess these effects, the impact of each alternative was determined by calculating generation, capital improvement, and other power system costs predicted for each policy alternative, and then comparing those costs to the Base Case.

As previously noted, TVA performs power system studies semi-annually to forecast the future 20-year energy demand. To maintain consistency with the balance of TVA's power system studies, the scope of the power generation studies performed in support of this EIS spans the 19-year period from 2004 through 2022. The 20-year forecast was extrapolated to estimate the forecast through 2030.

5.23.2 Impact Assessment Methodology

The impact of each alternative was measured by the increase or decrease in the power cost expected under the Base Case and that predicted for each policy alternative. For the Base Case, TVA's total power sales revenue was estimated for each year from 2004 to 2030 based upon the January 2003 power supply planning forecast. Then for each policy alternative, the change in power supply cost was estimated. The effects of each alternative were represented as an equivalent potential rate increase or the change in power supply cost as a percentage of total power sales revenue. This analysis was performed as follows:

- **Power Supply Analysis.** TVA performed an analysis to determine the effect on power supply costs of changes in hydropower and non-hydropower power production under each alternative. This analysis included the production cost of power; a reliability analysis; and costs associated with derate of coal and nuclear units, ancillary services, and other non-generating costs.

- **Economic Analysis.** The direct effects of the alternatives on power generation, as modeled by an equivalent potential rate increase, were used as inputs to the REMI model to evaluate their impact on the regional economy.

Power Generation Dispatch and Reliability

The power supply analysis included the use of three computer models: (1) the WSM for TVA's hydrological and hydroelectric system, (2) the RELY capacity planning model, and (3) the PROSYM power production costing model. The data and methodology used to estimate the impact on its system-wide power supply cost were the same data and models that TVA uses for operations and planning. A summary description of each of these models can be found in Appendix C, Model Descriptions and Results.

The evaluation process included five steps as follows:

Step 1. Hydropower Generation

Weekly water releases are scheduled to provide for benefits such as navigation, system minimum flows, and flood control. Hydropower generation is dispatched to most efficiently generate power using these releases. The WSM was used to simulate weekly hydropower generation production for each alternative based on hydrologic conditions, considering the various constraints on water releases for other purposes. TVA then subtracted the weekly hydroelectric power production predicted by the WSM from the total system demand.

Step 2. Reliability

For each alternative, TVA then evaluated the power system's ability to reliably meet the "hydro-adjusted" summer and winter peak loads using the RELY model. RELY is a generation reliability model used to determine the capacity needed to maintain the reliability of the power system. RELY calculated the TVA system loss of load probability (LOLP) hourly for the summer and winter peak load seasons through 2022. The results were based on generating resource capacity, power purchases, expected equivalent forced outage rates, planned outages, the hourly load forecast, contract load available for interruptions and load forecast uncertainty. The impact of the hourly dispatch was analyzed weekly to determine the changes in capacity needs under each alternative and to compare them to the capacity needs of the Base Case. If necessary to maintain acceptable reliability with respect to meeting the "hydro-adjusted" summer and winter load peaks, the additional fixed (capital) and variable (operations and maintenance, and fuel) cost of new generation resources, whether owned by TVA or contracted by TVA with other generators, was determined. For the purpose of this analysis, TVA has assumed that any new capacity would be gas-fired combined-cycle (baseload) or simple-cycle (peaking). Implementation of any alternative could affect the environment and would require environmental review and other studies to select the preferred type of new capacity.

Step 3. Dispatch of Non-Hydropower Generation

The PROSYM dispatch model was then used to determine the most efficient combination of non-hydropower generation assets to meet the "hydro-adjusted" power demand. PROSYM, combined with TVA's power generation system data, was used to determine which generating resources should be operated to meet demand at the lowest cost. The PROSYM model scheduled all of TVA's other power resources on an hourly basis and estimated the effects of the alternatives on power supply cost. These effects include the associated re-dispatch in fossil units, purchase and sale of power outside TVA power system, ancillary services, emissions, the incremental nuclear outages associated with essential cooling water temperature limitations, and the operating costs of existing cooling towers to reduce the amount of thermal plant discharges in order to avoid coal and nuclear unit derates.

TVA currently operates cooling towers at Watts Bar, Browns Ferry, and Sequoyah Nuclear Plants and the Paradise Fossil Plant. Watts Bar Nuclear Plant condenser cooling water is cooled continuously by its towers, while the others use the cooling towers for some period of time each year to supplement their once-through cooling systems. Cooling tower use reduces the amount of heat discharged to the Tennessee River by these plants, which helps TVA comply with water temperature limits (see Section 2.3.3). The costs to operate these cooling towers are a part of the cost of power.

Step 4. Coal Unit Derates

TVA used its water quality models to simulate operations for each of the alternatives and predict water temperatures at the coal and nuclear plant discharge structures. These predicted water temperatures were compared with NPDES permit and NRC license limitations, and units were derated or shut down to maintain compliance. The potential nuclear unit derates and shutdowns due to essential cooling water temperature limitations were accounted for in the PROSYM model, using thermal-forced outage rates during the appropriate seasons. The effect of each alternative on coal unit derates, however, was not included in the PROSYM analysis and was estimated separately.

The cost of generation losses due to coal unit derates was valued differently for peak and off-peak power. The value of energy lost during peak periods was assumed to be the cost of replacing it with power purchased on an hourly basis in the bulk power market. Energy lost off-peak was valued by assuming replacement with energy from the most likely source, the next higher cost TVA coal units. The net cash impact off-peak was computed as the difference between the generating cost of the derated plant and the average generating costs of the replacement energy. For those periods when the replacement energy was expected to be at or below costs at the derated plants, the net cash impact was assumed to be zero.

Step 5. Other Non-Generation Costs

Other factors that affect the cost of meeting the power demand include the cost of aeration required to maintain DO concentrations in tailwaters, additional capital costs for construction of new cooling towers if necessary to reduce thermal plant derates, and the cost of shipping coal on the Tennessee River to fuel some of TVA's coal plants.

To maintain water quality below 16 of TVA's hydropower dams (see Appendix A, Table A-05), TVA currently supplements the DO concentrations by various methods, including auto-venting turbines, surface water pumps, oxygen injection systems, aerating weirs, and blowers (see Section 2.3.6). The cost includes purchase, installation, and operation and maintenance of aeration equipment.

The analysis of the alternatives revealed that, although the additional use of existing cooling towers would be needed at times, no new cooling towers would be warranted. Only the cost of additional use of existing cooling towers is included in the power cost impacts.

Coal that fuels TVA's coal-fired power plants is currently shipped via barge to some plants; rail and truck transport are also used for coal deliveries in some cases. Depending on location, barge transport is often the lowest-cost method of transport (see Section 5.21, Navigation). The cost of shipping coal is also a part of the fuel cost and therefore a part of the total cost of power.

5.23.3 Base Case

Under the Base Case, the power system would be operated to provide for the changing power demand from 2004 through 2030 at the lowest cost, based on current and forecast conditions. The Base Case also differs from existing conditions as a result of capacity additions from the HMOD projects and at Browns Ferry Nuclear Plant, and increased operational flexibility provided by the Hydro Automation Program (as described in Section 3.3.1).

Power Generation Dispatch and Reliability

The mix of generation dispatched to meet demand under the Base Case would remain similar to current conditions, with hydropower generation dispatched primarily to meet peak power needs. Planned nuclear and hydropower capacity additions would support a portion of the changing demand. The shift from industrial to residential and commercial load forecast for the period through 2030 would mean a greater need for on-peak energy supplied by hydropower and other peaking resources. Additional peaking capacity would be needed to maintain acceptable system reliability. Since hydropower resources would grow very little, this need for additional on-peak energy would be met by first shifting any hydropower that is currently off-peak to on-peak. The balance of on-peak generation required would be provided by increased operation of TVA's combustion turbine and pumped storage units and generation purchased from non-TVA generators.

Although no nuclear plant shutdowns have occurred historically as a result of the essential cooling water temperature limitations of the NRC license, severe meteorological conditions (hot, dry summers) similar to those experienced in the summer of 1993, could result in forced shutdowns of one or more TVA nuclear units for several days every 10 years on average under the Base Case. The effects of these conditions were included in the reliability and power supply analyses and factored into the power supply costs for the Base Case.

Coal Unit Derates

Under the Base Case, some derate of the coal units would be necessary to maintain compliance with NPDES temperature limits, similar to existing conditions.

Other Non-Generation Costs

Existing aeration facilities would continue to be operated similar to present levels in order to achieve existing DO targets.

The restart and operation of Browns Ferry Unit 1 will require construction of an additional cooling tower. Use of cooling towers would increase to ensure that the maximum cooling water discharge temperature and the temperature rise between intake and discharge, as measured by stations in the reservoir, remain within approved regulatory limits.

Coal shipping costs would be similar to existing costs.

Power Supply Costs

The total power sales revenue for the Base Case was estimated for each year from 2004 to 2030 based on the January 2003 power supply planning forecast. This forecast included the consideration of all the power supply and non-generating costs described for the Base Case.

5.23.4 Reservoir Recreation Alternative A

Power Generation Dispatch and Reliability

As detailed in Table 5.23-01 and Table 5.23-02, the timing of hydropower generation would be shifted under Reservoir Recreation Alternative A from late summer, (when the peak demand is highest and, therefore, replacement energy is most costly), to early winter (when replacement energy is less costly). The total annual hydropower generation on average would be similar to, although slightly higher than, the hydropower generation expected under the Base Case (Table 5.23-02). In response to the shift in hydropower generation, other more costly peaking generation resources, such as coal, combustion turbine units, Raccoon Mountain pumped storage, or purchased power, would be dispatched to replace the reduced hydropower generation during these times. In addition, because hydropower is shifted off peak, it could displace some coal-fired generation.

Similar to (although more often than) the Base Case, severe meteorological conditions like those experienced in summer 1993, could result in forced nuclear plant shutdowns of one or more TVA nuclear units for several days every 10 years on average. These shutdowns could be required to comply with the essential cooling water temperature limitations of the NRC license. The effects of these conditions were included in the reliability and power supply analyses, and were factored into the power supply costs for Reservoir Recreation Alternative A.

Table 5.23-01 Effect of Policy Alternatives on Hydropower Generation Relative to the Base Case

Alternative	January–March (Weeks 1–12)	April–May (Weeks 13–21)	June–July (Weeks 22–30)	August–Labor Day (Weeks 31–35)	Labor Day–December (Weeks 36–52)
Reservoir Recreation A	Somewhat higher generation due to higher winter levels		Much lower generation due to releases of only minimum flows	Much lower generation; hydro releases are still restricted, but increased minimum flows would reduce losses	Somewhat higher generation as unrestricted drawdown resumes
Reservoir Recreation B and Tailwater Recreation	Much higher generation due to higher winter levels		Much lower generation due to releases of only minimum flows		Slightly lower; unrestricted drawdown resumes but only to higher winter levels
Summer Hydropower	Somewhat higher generation due to higher winter levels		Much higher generation due to unrestricted drawdown		Much lower; unrestricted drawdown resumes but only to higher winter levels
Equalized Summer/ Winter Flood Risk	Much higher generation due to higher winter levels		Much lower due to generally lower summer levels and releases of only minimum flows unless additional is necessary to maintain flood storage	Much lower; releases are still restricted, but increased minimum flows would reduce losses	Much lower due to higher winter reservoir levels
Commercial Navigation	Hydropower generation is very similar to the Base Case				
Tailwater Habitat	Much higher generation due to higher winter levels		Much lower due to releases of only minimum flows		Similar generation
Preferred	Somewhat higher generation due to higher winter levels		Much lower generation; hydro releases are still restricted, but increased minimum flows through this period would reduce losses		Slightly lower; unrestricted drawdown resumes but only to higher winter levels

Table 5.23-02 Effect of Policy Alternatives on Shift of Hydropower Generation Relative to the Base Case

Alternative	Increase/Decrease in Hydropower Generation as a Percentage of Base Case Hydropower Generation					
	January–March (Weeks 1–12) (%)	April–May (Weeks 13–21) (%)	June–July (Weeks 22–30) (%)	August–Labor Day (Weeks 31–35) (%)	Labor Day–December (Weeks 36–52) (%)	Annual (%)
Reservoir Recreation A	6	7	-19	-16	6	0.5
Reservoir Recreation B	14	13	-19	-39	-2	-1.3
Summer Hydropower	9	7	30	6	-30	-0.9
Equalized Summer/ Winter Flood Risk	14	26	-24	-19	-22	-4.9
Commercial Navigation	1	7	-1	0	-1	0.5
Tailwater Recreation	Similar to Reservoir Recreation B					
Tailwater Habitat	11	13	-19	-37	-1	-1.6
Preferred	6	8	-11	-12	-2	-0.4

Note: A negative number indicates that hydropower generation under the alternative would be less than under the Base Case. A positive number indicates that hydropower generation under the alternative would be more than under the Base Case.

Source: TVA Weekly Scheduling Model.

Coal Unit Derates

The reduction in summer hydropower production would be offset to some extent by maintaining the average weekly 25,000-cfs flow at Chickamauga Reservoir to provide cooling water for power plants and minimize summer power plant derates. Even with these higher minimum flows under Reservoir Recreation Alternative A, additional derates of the coal units relative to the Base Case would be necessary to maintain compliance with NPDES temperature limits. The estimated cost of these additional derates is presented in Table 5.23-03.

Other Non-Generation Costs

Aeration costs under Reservoir Recreation Alternative A would be higher than under the Base Case and would include a capital cost expenditure for additional equipment in 2004 and an annual operations and maintenance cost for each year from 2004 through 2030. There would be no change in coal shipping rates (Table 5.23-03).

Power Supply Costs

The effect of power generation dispatch, generation losses at coal and nuclear plants due to water temperature limits, and cost for additional cooling tower use on power supply costs was estimated for each year from 2004 to 2030. The average change in power cost for Reservoir Recreation Alternative A could be represented by a hypothetical rate increase of 0.3 percent, as shown in Table 5.23-03.

Table 5.23-03 Impacts on Power Generation—Annual Production Costs (2010) (dollars in millions)

Alternative	Power Supply Costs	Coal Unit Derate Costs	Aeration Equipment Costs	TVA Coal Shipping Costs	Total Costs	Hypothetical Rate Increase[1] (percent)
Base Case	$0	$0	$0	$0	$0	0%
Reservoir Recreation A	$28	$1.1	$0.6	$0	$30	0.3%
Reservoir Recreation B	$65	$1.3	$0.8	$0	$67	0.6%
Summer Hydropower	-$4	$0.8	$0.4	$6	$3	0.0%
Equalized Summer/ Winter Flood Risk	$104	$3.8	$0.7	$0	$108	1.2%
Commercial Navigation	-$4	$0.4	$0.6	-$9	-$11	-0.1%
Tailwater Recreation	$65	$0.2	$0.7	$0	$66	0.6%
Tailwater Habitat	$294	-$0.2	$0.7	$0	$295	3.3%
Preferred	$13	-$0.2	$1.2	$0	$14	0.2%

Note: Projected costs for 2010 are indicative of trends.

[1] The total costs are expressed as a percentage of total annual TVA power sales revenues each year for the period 2004 through 2030, and the hypothetical rate increase is the 27-year average of these percentages.

Source: TVA Power Planning Group.

5.23.5 Reservoir Recreation Alternative B and Tailwater Recreation Alternative

Power Generation Dispatch and Reliability

Under Reservoir Recreation Alternative B and the Tailwater Recreation Alternative, the effect on hydropower generation would be similar to Reservoir Recreation Alternative A although more adverse. The total annual hydropower generation on average would be about 1 percent less than the hydropower generation expected under the Base Case (Table 5.23-02). The timing of the generation would be shifted under Reservoir Recreation Alternative B and the Tailwater Recreation Alternative from late summer to early winter (Table 5.23-02), reducing the availability of hydropower to meet summer peak loads. As in Reservoir Recreation Alternative A, although to a greater extent, other higher marginal cost peaking generation units would need to be run to replace the shifted hydropower generation.

Similar to (although more often than) Reservoir Recreation Alternative A, forced nuclear plant shutdowns of one or more TVA nuclear units for several days every 10 years on average would be necessary to comply with the essential cooling water temperature limitations of the NRC license. The effects of these conditions were included in the reliability and power supply analyses, and were factored into the power supply costs for Reservoir Recreation Alternative B and the Tailwater Recreation Alternative.

Coal Unit Derates

Continuation of releases from Chickamauga Reservoir at the present 13,000-cfs level, coupled with the shift of hydropower generation from summer to fall, would increase slightly the frequency of derating coal units under Reservoir Recreation Alternative B over that expected under Reservoir Recreation Alternative A. Under the Tailwater Recreation Alternative, the additional releases for tailwater recreation would almost eliminate additional coal unit derates as compared to the Base Case.

Other Non-Generation Costs

Aeration costs under Reservoir Recreation Alternative B would be slightly higher than under Reservoir Recreation Alternative A; under the Tailwater Recreation Alternative, costs would be slightly lower than under Reservoir Recreation Alternative B. There would be no change in coal shipping rates.

Power Supply Costs

The average change in power cost could be represented by a hypothetical rate increase of 0.6 percent for both Reservoir Recreation Alternative B and the Tailwater Recreation Alternative, as shown in Table 5.23-03.

5.23.6 Summer Hydropower Alternative

Power Generation Dispatch and Reliability

Under the Summer Hydropower Alternative, the effect on hydropower generation relative to the Base Case would be to decrease hydropower generation in fall when generation is less valuable and increase hydropower generation during the summer and winter peak demand periods (Table 5.23-01). Although the total annual hydropower generation on average would be about 1 percent lower than the hydropower generation expected under the Base Case (Table 5.23-02), availability of the hydropower generation during the peak demand periods offsets somewhat the use of higher cost generation, leaving the overall power supply costs essentially the same as the Base Case.

The Summer Hydropower Alternative would reduce the number of days that one or more nuclear units would need to be shutdown once every 10 years on average to comply with the essential cooling water temperature limitations of the NRC license. The effects of these conditions were included in the reliability and power supply analyses, and were factored into the power supply costs for the Summer Hydropower Alternative.

Coal Unit Derates

Reservoir releases to maximize summer hydropower generation would not be sufficient to avoid additional coal unit derates; the costs are indicated in Table 5.23-03.

Other Non-Generation Costs

Aeration costs for the Summer Hydropower Alternative would be lower than under Reservoir Recreation Alternative A but similarly include a capital cost expenditure for additional equipment in 2004, and an annual operations and maintenance cost for each year from 2004 through 2030. Reservoir operations under the Summer Hydropower Alternative would also hamper navigation and increase the shipment cost of coal for TVA's coal units.

Power Supply Costs

Under the Summer Hydropower Alternative, there would be essentially no change in average power cost, as shown in Table 5.23-03.

5.23.7 Equalized Summer/Winter Flood Risk Alternative

Power Generation Dispatch and Reliability

Under the Equalized Summer/Winter Flood Risk Alternative, the effect on hydropower generation relative to the Base Case would be a decrease in hydropower generation in summer and fall and an increase during winter (Table 5.23-02). As under Reservoir Recreation Alternative A, Reservoir Recreation Alternative B, and the Tailwater Recreation Alternative, although to a greater extent, other higher marginal cost peaking generation units would need to be run to replace the shifted hydropower generation. In addition to the shift in hydropower, the net average annual hydropower generation loss under the Equalized Summer/Winter flood Risk Alternative relative to the Base Case would be almost 5 percent (Table 5.23-02) due to lower reservoir levels and the resulting lower head on the hydropower units. This loss in total annual generation is large enough to necessitate the purchase of additional baseload energy in addition to the peaking generation to offset shifts.

Under the Equalized Summer/Winter Flood Risk Alternative, similar to (although more often than) Reservoir Recreation Alternative B and the Tailwater Recreation Alternative, additional nuclear plant shutdowns would be necessary to comply with the essential cooling water temperature limitations of the NRC license. The effects of these conditions were included in the reliability and power supply analyses, and were factored into the power supply costs for the Equalized Summer/Winter Flood Risk Alternative.

Coal Unit Derates

The generally lower summer reservoir levels maintained for flood storage under the Equalized Summer/Winter Flood Risk Alternative would reduce the volume of water available for release in late summer, when water temperatures are highest. Of all alternatives, consequently, the Equalized Summer/Winter Flood Risk Alternative would cause the greatest losses due to coal unit derates.

Other Non-Generation Costs

Increased aeration costs for the Equalized Summer/Winter Flood Risk Alternative include a capital cost expenditure for additional equipment in 2004 and an annual operations and maintenance cost for each year from 2004 through 2030. These costs under the Equalized Summer/Winter Flood Risk Alternative would be similar to those under the Tailwater Recreation Alternative. Coal shipping rates would not change.

Power Supply Costs

The average change in power cost under the Equalized Summer/Winter Flood Risk Alternative could be represented by a hypothetical rate increase of 1.2 percent, as shown in Table 5.23-03.

5.23.8 Commercial Navigation Alternative

Power Generation Dispatch and Reliability

Hydropower generation under the Commercial Navigation Alternative would be very similar to the Base Case, with little shift in hydropower generation. Net average annual hydropower generation would be less than 1 percent higher than the Base Case (Table 5.23-02), reflecting a minimal gain due to higher winter levels on the mainstem reservoirs. Power generation dispatch would generally not change under the Commercial Navigation Alternative relative to the Base Case.

Under the Commercial Navigation Alternative, the nuclear plant shutdowns necessary to comply with the essential cooling water temperature limitations of the NRC license would be similar to those under the Base Case.

Coal Unit Derates

Reservoir releases for commercial navigation would not be sufficient to avoid all additional coal unit derates under the Commercial Navigation Alternative.

Other Non-Generation Costs

Increased aeration costs under the Commercial Navigation Alternative would be similar to those for the Base Case. The Commercial Navigation Alternative would increase water levels in the mainstem reservoirs to improve navigation and decrease the shipment cost of coal for TVA's coal units.

Power Supply Costs

The average change in power cost for the Commercial Navigation Alternative could be represented by an equivalent potential rate decrease of 0.1 percent, as shown in Table 5.23-03.

5.23.9 Tailwater Habitat Alternative

Power Generation Dispatch and Reliability

Under the Tailwater Habitat Alternative, reservoir releases would produce variable flows, water depths, and velocities throughout the year that would be more similar to the seasonal variability of runoff and would reduce hourly and daily variability of flows in tailwaters. Actual releases would be determined by the inflow conditions. Peaking hydropower operations would not occur unless the low flow falls below the level needed to operate one unit; then peaking would occur only to the extent necessary to peak one unit at its most efficient setting.

The effect on hydropower generation relative to the Base Case would be a decrease in hydropower generation in summer and fall and an increase during winter and spring (Table 5.23-01). The Tailwater Habitat Alternative would shift the greatest amount of hydropower generation away from May through September. As with all of the alternatives, TVA's response to this shift in hydropower generation would be to replace it with the lowest marginal cost alternative generation resource. Depending on the marginal costs of replacement generation during the May-to-September period, the shifted hydropower generation could be replaced by coal, combustion turbines, pumped storage, or purchased generation. The hydropower that is shifted out of summer would likely also displace coal generation.

Net average annual hydropower generation would be 1.6 percent lower than the Base Case (Table 5.23-02) but would not be large enough to warrant purchase of additional baseload generation.

The nuclear plant shutdowns necessary to comply with the essential cooling water temperature limitations of the NRC license under the Tailwater Habitat Alternative would be similar to those under the Base Case.

Coal Unit Derates

Reservoir releases under the Tailwater Habitat Alternative would improve water temperatures sufficiently to reduce the generation losses due to coal unit derates relative to those expected under the Base Case.

Other Non-Generation Costs

Increased aeration costs under the Tailwater Habitat Alternative would include a capital cost expenditure for additional equipment in 2004 and an annual operating and maintenance cost for each year from 2004 through 2030. These costs under the Tailwater Habitat Alternative would be similar to those under the Tailwater Recreation Alternative. Coal shipping rates would not change.

Power Supply Costs

The Tailwater Habitat Alternative would result in the greatest adverse impact on power costs, with an average change in power cost represented by a hypothetical rate increase of 3.3 percent, as shown in Table 5.23-03.

5.23.10 Preferred Alternative

Power Generation Dispatch and Reliability

For the Preferred Alternative, the total annual hydropower generation on average would be similar to (although slightly lower than) the hydropower generation expected under the Base Case (Table 5.23-02). As detailed in Table 5.23-01 and Table 5.23-02, the timing of hydropower generation would be shifted under the Preferred Alternative from summer (when the peak demand is highest and, therefore, replacement energy is most costly) to winter and early spring (when replacement energy is generally less costly). In response to the shift in hydropower generation, other more costly peaking generation resources (such as coal, combustion turbine units, Raccoon Mountain pumped storage, or purchased power) would be dispatched to replace the reduced hydropower generation during these times. In addition, because hydropower is shifted off peak, it could displace some coal-fired generation.

Similar to (although more often than) Reservoir Recreation Alternative A, nuclear plant shutdowns of one or more TVA nuclear units for several days every 10 years on average would be necessary to comply with the essential cooling water temperature limitations of the NRC license. The effects of these conditions were included in the reliability and power supply analyses, and were factored into the power supply costs for the Preferred Alternative.

Coal Unit Derates

Reservoir releases under the Preferred Alternative would improve cooling water availability or temperatures sufficiently to reduce somewhat the frequency of generation losses due to coal unit derates as compared to those expected under the Base Case.

Other Non-Generation Costs

Under the Preferred Alternative, aeration costs would be substantially higher than under the Base Case and all alternatives considered. The costs would include a capital cost expenditure for additional equipment, expended over a 3-year period from 2004 through 2006 due to the larger costs, and an annual operations and maintenance cost for each year from 2004 through 2030. Coal shipping rates would not change (Table 5.23-03).

Power Supply Costs

The average change in power cost under the Preferred Alternative could be represented by a hypothetical rate increase of 0.2 percent, as shown in Table 5.23-03.

5.23.11 Summary of Impacts

Table 5.23-04 presents a summary of impacts on power by policy alternative. Under each alternative, the use of hydropower generation would shift among the seasons, with hydropower generation during each season either higher or lower than that expected under the Base Case, as presented in Table 5.23-01 and Table 5.23-02. Under all alternatives except the Summer Hydropower Alternative, hydropower generation would generally decrease in summer when the peak demand is highest and replacement energy is most costly, and increase in winter and spring when energy is less valuable. The Commercial Navigation Alternative would shift the least amount of hydropower generation away from summer, followed in order of increasing effect by the Preferred Alternative, Reservoir Recreation Alternative A, the Equalized Summer/Winter Flood Risk Alternative, the Tailwater Habitat Alternative, and Reservoir Recreation Alternative B. Under the Summer Hydropower Alternative, hydropower generation would shift from fall, when peak demand is lowest, to the summer and winter peak periods.

The change in dispatch of other power resources in response to hydropower generation shifts would result in the use of more (or in the case of the Summer Hydropower Alternative less) costly generation resources. At times, additional generation capacity would be needed to ensure acceptable system reliability. Under all alternatives except the Summer Hydropower Alternative, the shift in hydropower generation would create the need for increased use of combustion turbines, pumped storage, and purchased power for peaking. The hydropower that is shifted out of summer would likely also displace coal generation. In addition to the shift in hydropower generation away from periods of peak demand, requiring the acquisition of additional peaking generation, the Equalized Summer/Winter Flood Risk Alternative would cause a net annual loss in hydropower generation large enough to necessitate the purchase of additional baseload capacity.

Alternatives that reduce reservoir releases in late summer when water temperatures are highest would also increase the generation lost due to coal and nuclear unit derates. Additional derate of coal units would be necessary under all alternatives except the Preferred Alternative and the Tailwater Habitat Alternative, which show a slight reduction in the cost of coal unit derates.

A third impact on the cost of power production arises from alternatives that would decrease reservoir DO levels. To maintain current targets for tailwater DO levels, additional aeration would be required under all alternatives.

Finally, under those alternatives that would change water levels and flows in the mainstem reservoirs to the extent that navigation would be affected (the Summer Hydropower Alternative and the Commercial Navigation Alternative), the shipment cost of coal for TVA's coal units would change.

The Commercial Navigation Alternative is expected to slightly reduce power costs relative to the Base Case by 0.1 percent over the 2003 through 2030 period. The Summer Hydropower Alternative is expected to result in essentially no effect on power costs relative to the Base Case. The remaining six policy alternatives are expected to increase power costs. Of these six, the greatest increase in power costs relative to the existing operations policy is expected under the Tailwater Habitat Alternative, which is estimated to increase power costs by an average of 3.3 percent over the 2003-through-2030 period. The least increase in power costs relative to the existing operations policy is expected under the Preferred Alternative, which is estimated to increase power costs by an average of 0.2 percent over the period from 2003 through 2030.

Table 5.23-04 Summary of Impacts on Power by Policy Alternative

Alternative	Description of Impacts
Base Case	Power generation would continue to follow existing trends; the annual energy load is expected to increase 1.6 percent on average from 2004 through 2020. The industrial load growth is expected to slow, reducing the demand from the industrial client base and increasing the demand by the commercial and residential clients; this shift would require more peaking and less baseload capacity throughout the 2003 to 2030 period.
Reservoir Recreation A	Total power cost would increase $30 million annually (2010). The total annual hydropower generation would be similar to the Base Case; however, the timing would be shifted from late summer, when the peak demand is highest and replacement energy is most costly, to early winter when energy is less costly. Other more costly generation, such as coal or combustion turbine units, would be dispatched to replace the shifted hydropower generation. • Hydropower generation similar to Base Case • Additional coal derates • Additional nuclear shutdowns • Additional aeration costs • No additional coal shipping costs
Reservoir Recreation B	Total power cost would increase $67 million annually (2010). The effect on hydropower generation would be similar to Reservoir Recreation Alternative A, although more adverse. • Hydropower generation slightly lower than Base Case • Additional coal derates • Additional nuclear shutdowns • Additional aeration costs • No change to coal shipping costs
Summer Hydropower	Total power cost would increase $3 million annually (2010). The effect on hydropower generation relative to the Base Case would be to decrease hydropower generation in fall and increase hydropower generation during the summer and winter peak demand periods. Availability of the hydropower generation during the peak demand periods offset the use of higher cost generation, leaving the overall power supply costs essentially the same as the Base Case. • Hydropower generation slightly lower than Base Case • Additional coal derates· • Fewer nuclear shutdowns • Additional aeration costs • Higher coal shipping costs

Table 5.23-04 Summary of Impacts on Power by Policy Alternative (continued)

Alternative	Description of Impacts
Equalized Summer/Winter Flood Risk	Total power cost would increase $108 million annually (2010). The effect on hydropower generation relative to the Base Case would be to decrease hydropower generation in summer and fall and increase hydropower generation during the winter and spring runoff periods. Other more costly generation, such as coal or combustion turbine units, would be dispatched to replace the shifted hydropower generation. • Greatest loss in hydropower generation of all alternatives • Additional coal derates • Additional nuclear shutdowns • Additional aeration costs • No additional coal shipping costs
Commercial Navigation	Total power cost would decrease $11 million annually (2010). The effect on hydropower generation would be very similar to the Base Case with little shift in hydropower generation. • Hydropower generation similar to the Base Case • Additional coal derates· • No additional nuclear shutdowns · • Additional aeration costs· • Lower coal shipping costs
Tailwater Recreation	Total power cost would increase $66 million annually (2010). The effect on hydropower generation would be similar to Reservoir Recreation Alternative B. • Hydropower generation slightly less than Base Case • Additional coal derates but much less than Reservoir Recreation Alternative B • Additional nuclear shutdowns • Additional aeration costs· • No additional coal shipping costs
Tailwater Habitat	Total power cost would increase $295 million annually (2010). The effect on hydropower generation would be similar to Reservoir Recreation Alternative A although much more adverse. Peaking hydropower operations would be very limited. • Hydropower generation slightly less than Base Case • No additional coal derates· • No additional nuclear shutdowns • Additional aeration costs· • No additional coal shipping costs

Table 5.23-04 Summary of Impacts on Power by Policy Alternative (continued)

Alternative	Description of Impacts
Preferred	Total power cost would increase $14 million annually (2010). The total annual hydropower generation would be similar to the Base Case; however, the timing would be shifted from late summer, when the peak demand is highest and replacement energy is most costly, to early spring when energy is less costly. Other more costly generation, such as coal or combustion turbine units, would be dispatched to replace the shifted hydropower generation. • Hydropower generation similar to Base Case • Fewer coal derates • Additional nuclear shutdowns • Additional aeration costs • No additional coal shipping costs