US Army Corps of Engineers®
Savannah District

Hartwell Lake Integrated Water Supply Storage Reallocation Report

South Carolina and Georgia

March 2024

Contents

LIST OF TABLES

LIST OF FIGURES

Introduction

This report, prepared by the Hydropower Analysis Center (HAC) for the Savannah District presents an analysis of hydropower impacts of reallocating reservoir storage in Lake Hartwell to accommodate increased customer demand. The study's alternative scenarios consider demand growth from existing customers, the addition of new customer storage accounts, and the potential for return flow credits that alter storage and withdrawal accounting.

Hartwell Dam is at Savannah River mile 305.0, located 7 miles below the confluence of the Tugaloo and Seneca Rivers and 7 miles east of Hartwell, Georgia. Hartwell Dam is the upper most of three U. S. Army Corps of Engineers multipurpose projects in the upper Savannah River Basin. The two projects downstream are Richard B. Russell Lock and Dam then J. Strom Thurmond Lock and Dam, shown in Figure 1. The three-project system is authorized and operated to maximize the public benefits of hydroelectric power, flood damage reduction, recreation, fish and wildlife, water supply and water quality.

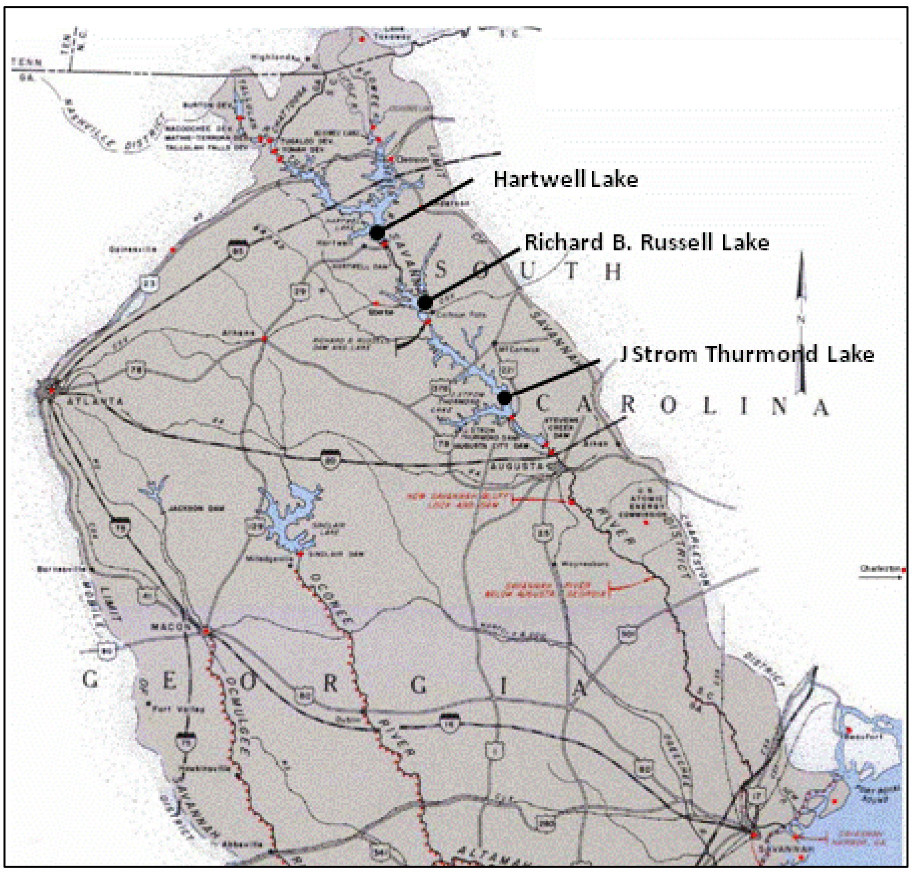

Figure 1 - Location of Savannah River Basin Projects

A simulation was conducted in which the three power plants were regulated for the (1939-2013) period of record using HEC-ResSim ("ResSim"), a sequential streamflow model used to estimate daily operating conditions and output under varying assumptions regarding water supply. HAC utilized the ResSim output provided by Savannah District and the Hydrologic Engineering Center (HEC), as well as historical and forecasted energy market data to analyze the potential impacts to generation, dependable capacity, and revenues that accrues to the federal power marketing administration (FMA) and Southeastern Power Administration (SEPA) resulting from reallocation of water storage in Lake Hartwell.

Previous analyses by HAC completed in 2020-2022 studied the hydropower impacts of several alternative reallocation scenarios. This update, focused on Alternative 2 from the original study, includes the sensitivity of impact estimates to return flow crediting by adding a new alternative (Alternative 5). HAC analyzed the streamflow modeling results provided by Savannah District for both the new Alternative 5 (reallocation with RFCs) and the original Alternative 2 (reallocation from the conservation pool without RFCs). As expected, the results of the two alternatives pertaining to hydropower are identical; return flow credit is a water accounting matter, rather than a physical hydrologic change in the reservoir or flow through the dams' turbines.

Update Study Alternatives

The impacts of the following alternative actions are analyzed herein. These alternatives were selected from a larger list considered in the Hartwell Lake Integrated Water Reallocation Study thus far; full descriptions of each and the screening process can be found in the main report. The two action alternatives in this update differ in the inclusion (or omission) of return flow credits, which essentially assumes that account holders may receive storage credit for any withdrawn water that they return to the reservoir, thus reducing the additional storage needed to accommodate the increased demands. As storage accounting does not physically impact hydropower capability under typically expected hydrologic conditions, the hydropower results associated with Alternative 2 and Alternative 5 are identical throughout.

- **Baseline** or **"future without project"**: Storage account sizes remain unchanged from current conditions, with expected future demands and no new water supply accounts
- **Alternative 2**: Operations with expected future demands and after increasing the storage account sizes to accommodate the future demand requests, not accounting for return flow credits
- **Alternative 5**: Operations with expected future demands and after increasing the storage account sizes to accommodate the future demand requests, accounting for return flow credits.

Study Assumptions

The following general assumptions underlie HAC's analysis. Other specific assumptions and inputs enter the analysis and are described in the relevant sections below.

- The hydrological period of record for ResSim output was 1939-2013. The output for the first January in the period and last December were incomplete. Therefore, for month-level energy generation estimates, output was averaged over the model years 1940 to 2012 for January and December
- Hydropower benefits were calculated over a 50-year future period starting in 2023
- The analysis employs the FY23 federal discount rate of 2.5% throughout.
- All dollar figures are stated in constant FY 2023 dollars.

Hydropower Impacts

HAC's analysis centers on two major values ("benefits") associated with hydropower operations: those of energy generation and dependable capacity. The procedures for computing the cost – or foregone benefits - of reallocating water from hydropower to water supply use are outlined in ER 1105-2-100, *Planning Guidance Notebook* (22 April 2000), Appendix E, paragraph E-57, d(2). These procedures require that the reallocation cost charged to water supply customers be the highest of the following:

- Power benefits foregone
- Power revenues foregone
- Replacement costs of power
- Updated cost of storage

Power benefits foregone, power revenue foregone, and the replacement costs of power are impacts to hydropower and are calculated in this report[1]. The updated cost of storage is not power related and will be computed by the Savannah District based on the storage reallocated.

Energy Generation Impacts

An estimate of the impacts to hydropower generation of the proposed actions was based on simulations of operations at USACE's upper Savannah River Basin dams under baseline (future demand with no action taken) and the proposed alternatives with varying storage account sizes and return flow accounting assumptions. Savannah District provided simulations of daily output from the ResSim model for each of the dams in the system for a 75-year period[2] under each of the alternative scenarios. Pumping energy consumption for the pump/generators at Richard B. Russell power plant was computed in a post-modeling process using pumping hour and generation factors provided by Savannah District.

Table 1 below summarizes annual energy produced by each project and the entire system under baseline conditions and each alternative scenario. Note that pumping energy at Russell appears as negative values because this this energy is consumed, rather than generated, by the project. On an annual system-level basis, generation decreases 0.2% in the reallocation scenario.

Table 1 – Simulated Average Annual Generation Impacts

	Hartwell		Russell		Thurmond		Russell Pumping*		System	
	Energy (MWh)	vs. baseline	Energy (MWh)	vs. baseline	Energy (MWh)	vs. baseline	Energy (MWh)	vs. baseline	Energy (MWh)	vs. baseline
Baseline	406,244		734,257		730,458		(331,921)		1,539,038	
Alt 2	404,677	(1,567)	734,507	251	729,462	(996)	(333,493)	(1,572)	1,535,153	(3,885)
Alt 5[3]	404,677	(1,567)	734,507	251	729,462	(996)	(333,493)	(1,572)	1,535,153	(3,885)

*Pumping at Russell consumes power rather than generate it. Entries are thus negative.

[1] Both energy and capacity benefits are based on their replacement costs; the replacement cost of power is therefore not calculated separately.
[2] The first and last years of ResSim output were incomplete. Therefore, most energy-related estimates were calculated using 73 complete years. Capacity-related estimates were calculated using the full 75-year period.
[3] Alternative 5 differs from Alternative 2 only in terms of storage accounting method. Hydropower results are thus identical.

Hydropower operations and the value of energy both vary according to hydrology, market conditions, and other factors which change materially throughout a given day, month, or year. It was thus necessary to estimate generation on an appropriately detailed level. Figure 2 summarizes average monthly generation at the system level under each alternative. Because the impacts are small, they are difficult to see in this figure.

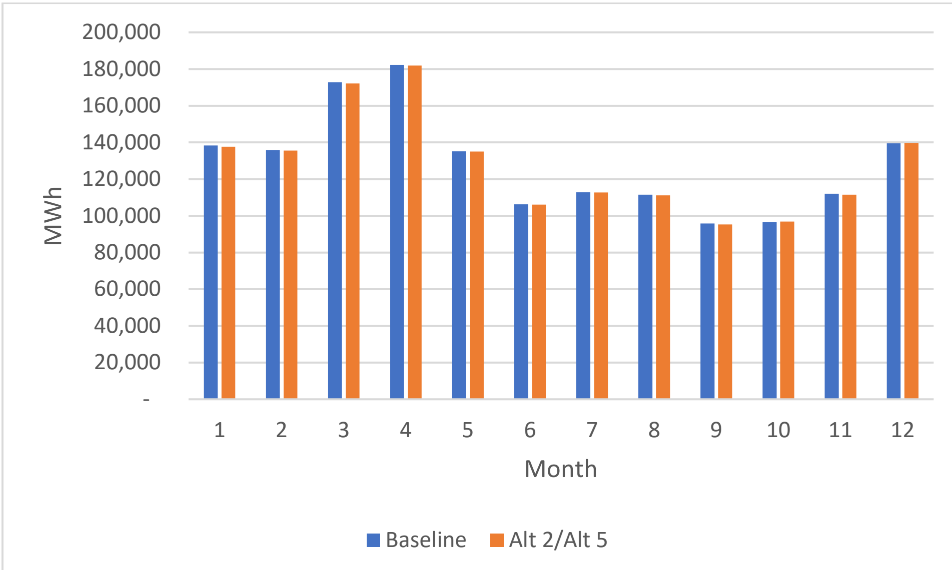

Figure 2 - Average Generation by Month, 3-Dam System Total

Generation also varies throughout the hours of the day, reflecting patterns in regional power demand and other market factors. For this study, daily simulated generation from ResSim was thus allocated to blocks of hours within each day. These generation blocks are defined primarily by energy demand, with a higher demand period spanning 6:00am to 10:00pm on weekdays. However, because generation by USACE hydropower plants in the region is further concentrated in a subset of the highest-value weekday peak hours to fulfill power contracts, these hours were evaluated separately as "contract" on-peak hours in order not to understate their value. Table 2 presents the distribution of hours into generation blocks for contract-peak hours, non-contract peak hours, and off-peak hours for each month of the year, and for weekends. The schedule of generation blocks was provided by SEPA, an agency of the U.S. Department of Energy.

Table 2 - SEPA Contract Blocks

	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours
Weekdays			
January	11	5	8
February	11	5	8

March	11	5	8
April	6	10	8
May	6	10	8
June	6	10	8
July	6	10	8
August	6	10	8
September	6	10	8
October	11	5	8
November	11	5	8
December	11	5	8
Weekends (All Year)			
All Months	0	0	24

As an example of how daily simulated energy production was allocated to generation blocks, Table 3 below shows the process for the Hartwell dam simulation corresponding to the hydrology of the relatively high generation week of March 23, 1998, under baseline conditions. Daily capability varies with hydrologic conditions; the simulated average capability on Monday of this week is 312.7 MW and simulated generation is 4,852 MWh. On-peak generation for 16 hours would be the entire 4,852 MWh, of which 11 hours would be SEPA contract peak generation (3,440 MWh) and the remaining 5 hours of on-peak generation would be non-contract (1,412 MWh). Generation in excess of 16 hours on the other weekdays of this week would be off-peak energy.

Table 3 - Generation Allocation to Contract Blocks, Example Week[4]

Date	Total Energy Generation (MWh)	Contract Peak (MWh)	Non-Contract Peak (MWh)	Off-Peak (MWh)	Weekend (MWh)
Monday, March 23, 1998	4,852	3,440	1,412	-	-
Tuesday, March 24, 1998	5,735	3,384	1,538	813	-
Wednesday, March 25, 1998	5,783	3,363	1,529	892	-
Thursday, March 26, 1998	5,704	3,360	1,527	817	-
Friday, March 27, 1998	5,678	3,339	1,518	821	-
Saturday, March 28, 1998	5,222	-	-	-	5,222
Sunday, March 29, 1998	5,471	-	-	-	5,471

This allocation process was applied to all 75 hydrologic years[1] of ResSim simulations to transform daily output to hourly (generation block) level figures. Table 4 summarizes these sub-daily allocations by month, averaged across the hydrologic period, for the baseline scenario at the 3-dam system level. Matching summaries for other study alternatives can be found in the appendix to this analysis.

[4] This table is for illustration purposes only.

Table 4 - Generation by Contract Block and Month, 3-Dam System Total, Baseline

Month	Contract peak	Non-contract peak	Off-peak	Weekend	Total
1	109,447	5,450	(24,751)	48,108	138,253
2	104,888	6,366	(20,753)	45,454	135,955
3	118,603	10,217	(10,917)	54,967	172,870
4	96,436	28,405	1,227	56,213	182,281
5	93,292	14,190	(22,439)	50,104	135,148
6	84,057	8,033	(27,676)	41,842	106,256
7	99,432	6,232	(34,976)	42,221	112,908
8	102,238	6,166	(38,704)	41,749	111,449
9	94,131	3,582	(39,977)	38,016	95,753
10	94,947	987	(38,847)	39,554	96,641
11	100,454	1,858	(32,394)	42,125	112,043
12	113,532	4,303	(26,731)	48,376	139,480
Block Total	1,211,459	95,789	(316,938)	548,728	1,539,038

Energy Value

Estimates of the economic value of the energy generation summarized above is based on detailed energy price forecasts for the market(s) relevant to dams in the region. These forecasts take annual, monthly, daily, and hourly variation in energy prices, as well as geography-specific factors that impact market supply, demand, and transmission, into account.

For this study, a forecast of hourly energy prices applicable to the upper Savannah River basin was produced from an annual-level forecast from the US Energy Information Administration (EIA) and locational marginal pricing (LMP) data obtained for the appropriate regional pricing node. Locational marginal pricing is a computational technique that determines the hourly “shadow price” for a marginal unit (MWh) of demand. Hourly LMP data was obtained from the Midcontinent Independent System Operator (MISO) website.

The EIA publishes an Annual Energy Outlook (AEO) that includes thirty years of annual average forecasted electricity prices for market regions and sub-regions of the US organized by the three service categories of generation, transmission, and distribution. The EIA’s 2022 AEO forecast for the generation service category formed the basis of the hourly, location-specific forecast used to value USACE output. Because the AEO forecast only spans 30 years (though 2050), prices were assumed to be constant in real terms for the remaining 20 years of this study’s analytical horizon.

The EIA’s annual price forecast is used to project LMP energy prices through a relatively simple process:

- First, the historical relationship between the annual region-wide values reported by the EIA and the hourly location-specific LMP values is established for each generation block (e.g., peak and off-peak) of the day.
- Then these estimated relationships are applied to future forecasted values from the EIA to produce generation block and location specific forecasted LMP values.

The historical relationships between the EIA values and the LMP values are estimated by calculating the ratio of LMP value (for the hour of the year) to the annual EIA-forecasted value for the preceding three-year (2017-2021) period, then averaging these hourly ratios within each of the generation blocks described above for each month of the year. HAC refers to these average ratios as “shaping ratios”. To match the hourly LMP data with the generation blocks, the data (prices) were sorted from high to low within each day, assuming that the highest LMP values are associated with the highest value block. Table 5 summarizes the resulting shaping ratios for each generation block and month of the year.

Table 5 - Regional Price Forecast/LMP Shaping Ratios

Month	Contract	Peak	Off Peak	Weekend
1	0.48	0.33	0.38	0.37
2	0.43	0.32	0.35	0.36
3	0.42	0.29	0.33	0.33
4	0.49	0.30	0.36	0.34
5	0.52	0.28	0.37	0.33
6	0.51	0.27	0.36	0.35
7	0.57	0.29	0.39	0.37
8	0.60	0.30	0.40	0.39
9	0.61	0.32	0.42	0.40
10	0.58	0.35	0.44	0.44
11	0.58	0.40	0.47	0.46
12	0.50	0.35	0.40	0.40

The EIA Annual Energy Outlook 2022 includes several scenarios - a Reference Case that serves as a baseline forecast (and which is used for the valuations in this study), and several alternate scenarios that take into account the uncertainty associated with different possible market conditions. These side cases are defined by assumptions regarding macroeconomic conditions, global oil and gas prices and supply, and renewable energy resource costs[5]. Figure 3 illustrates the AEO 2022 forecasts, and Table 6 summarizes the variability across cases, which reflects how sensitive the estimates presented next would be to uncertainty in future energy prices. Overall, prices across the 50-year forecast period range from about -7% to about +7% about the Reference Case.

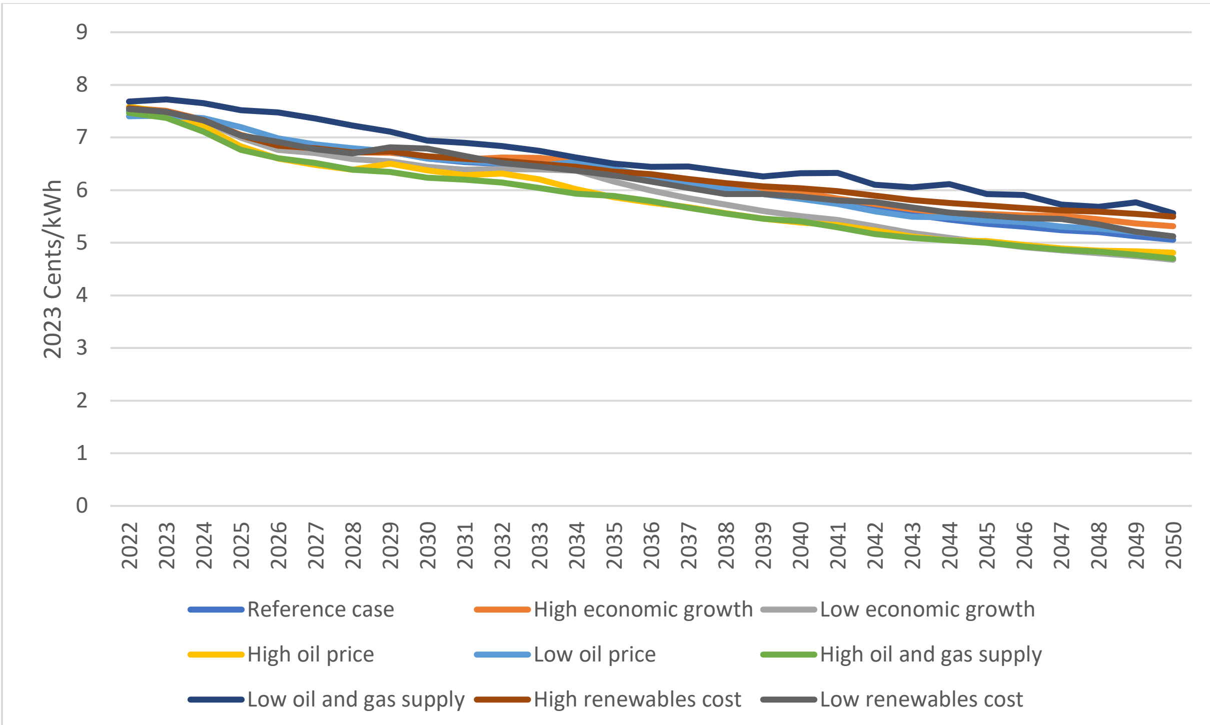

Figure 3 - AEO 2022 Price Forecasts for SERC-SE Region

Table 6 - AEO 2022 Price Forecast for SERC-SE Region, Side Cases

	Ref. Case	High econ. growth	Low econ. growth	High oil price	Low oil price	High oil/gas supply	Low oil/gas supply	High renew. Cost	Low renew. cost
2023	7.48	7.56	7.54	7.59	7.40	7.47	7.68	7.56	7.54
2035	6.38	6.37	6.17	5.87	6.40	5.89	6.50	6.35	6.28
2050	5.06	5.31	4.68	4.81	5.12	4.70	5.56	5.50	5.12

Energy Benefits Foregone

Combining the block-specific shaping ratios presented in Table 5 with the long-term annual price forecast illustrated in Figure 3 and Table 6 produces an hourly price forecast for the megawatt-hours generated at the three dams. Further combining this resulting price forecast with the generation estimates presented above (presented in part in Tables 3 and 4) produces estimates of the value of

[5] Full descriptions of forecast cases are available on the EIA website, www.eia.gov/outlooks/aeo/assumptions/case_descriptions.php

energy generated for each of this study's alternative scenarios. Table 7 summarizes these average annual impacts ("energy benefits foregone") that the alternatives would have during a 50-year period in monetary terms.

Table 7 – Energy Generation Value, 3-Dam System Total

	Average Annual Energy Value (2023$)	Change from baseline	% Change from baseline
Baseline	$46,698,012	n/a	n/a
Alt 2	$46,611,392	-$86,620	-0.2%
Alt 5[3]	$46,611,392	-$86,620	-0.2%

Capacity Impacts

In the context of this study capacity value (or "capacity benefits") is defined as the product of the change in dependable capacity and its per-unit market value (price) reflecting the fixed costs of constructing replacement thermal generating plant capacity for the lost hydropower.

Dependable Capacity

The dependable capacity of a hydropower project is a measure of the amount of capacity that the project can reliably contribute towards meeting system peak power demands. If a hydropower project always maintains approximately the same head, and there is always an adequate supply of stream flow so that there is enough generation for the full capacity to be usable in the system load, the full installed generator capacity can be considered "dependable".

At storage projects, normal reservoir drawdown can result in a reduction of capacity due to a loss in head. At other times, diminished stream flows during low flow periods may result in insufficient generation to support the available capacity in the load. *Dependable* capacity accounts for these factors by giving a measure of the amount of capacity that can be provided with some degree of reliability during peak demand periods.

Dependable capacity can be computed in several ways. The method that is most appropriate for evaluating the dependable capacity of a hydropower plant in a predominantly thermal generating plant-based power system is the Average Availability Method[6]. In the Average Availability Method, the occasional unavailability of a portion of a hydropower project's generating capacity due to hydrologic variations are treated in the same manner as the occasional unavailability of all or part of a thermal generating plant's generating capacity due to forced outages.

The dependable capacity calculation procedure for the three dams of interest begins with approximating the project's contribution in meeting the system capacity requirements for the regional critical year. The project's capacity contribution in each scenario was determined by first calculating its weekly average generation (MWh) for the simulated peak demand months of June through September of 1981 (the

[6] This method is described in Section 6-7g of EM 1110-2-1701, *Hydropower*, dated 31 December 1985.

project's critical water year as determined by SEPA) in the ResSim model baseline run. Average weekly energy is used to ensure that hourly/daily/weekly cycles in demand during the annual low water (hydropower)/high demand 4-month period are captured.

This number was then divided by SEPA's defined marketable capacity[7] for each project, yielding an estimate of the required/expected weekly hours of generation during the peak demand period in each simulated hydrologic year. Southeastern Power Administration determined the marketable capacities summarized in Table 8 based on the regional drought in 1981.

Table 8 - Marketable Capacity per SEPA

Project	Marketable Capacity per SEPA (MW)
Hartwell	396
Russell	605
Thurmond	288

Dividing the weekly average generation during peak months by the project's required/expected weekly average hours during peak months yields an array of potentially supportable capacity values. However, actual power produced is limited by the machine capability of the project. The actual supportable capacity for a given year is consequently the lesser of the potential supportable capacity and the project's the machine capability. With the Average Availability Method, dependable capacity is the average actual supportable capacity over the 75-year period[1] of record.

As an example of how dependable capacity is calculated, Table 9 shows the values described above for the baseline for simulation years 1980-1990 (not all simulation years or alternatives are displayed).

Table 9 - Dependable Capacity Calculation Example

Year	Average high demand weekly energy (MWh)	Potential supportable capacity (MW)	Machine capability (MW)	Actual supportable capacity (MW)
1980	10,475	434	359	359
1981	6,950	288	347	288
1982	11,359	471	358	358
1983	11,322	469	358	358
1984	16,658	690	361	361
1985	9,888	410	357	357
1986	6,685	277	343	277
1987	10,056	417	357	357
1988	6,708	278	344	278

7 Coordination with SEPA confirmed marketable capacity values for the Corps hydropower plants and the critical water year of 1981.

1989	11,602	481	362	362
1990	10,460	433	358	358

The average availability (dependable capacity) of the three projects across alternative scenarios is summarized in Table 10 below.

Table 10 - Dependable Capacity Impacts

	Hartwell	Russell	Thurmond	System Total	Change from baseline
Baseline	303.5	454.4	348.7	1,106.6	n/a
Alt. 2	303.5	455.3	348.8	1,107.5	0.9
Alt. 5[3]	303.5	455.3	348.8	1,107.5	0.9

Value of Dependable Capacity

Capacity value is an estimate of the fixed costs of the replacement capacity that would be needed to replace the capacity lost to operational, hydrological, or structural changes to hydropower resources. This value is calculated as the product of the change in dependable hydropower capacity (in MW, Table 10 above) and its per-MW replacement cost (price), which is in turn based on the costs associated with the most likely combination of replacement resources.

To determine the most likely replacement resources for foregone hydropower capacity, three thermal resource types were considered: gas-fired combustion turbine, gas-fired combined cycle turbine, and coal steam plant, which reflect the current thermal electric generation mix (Figure 4) and projected capacity additions in the region.

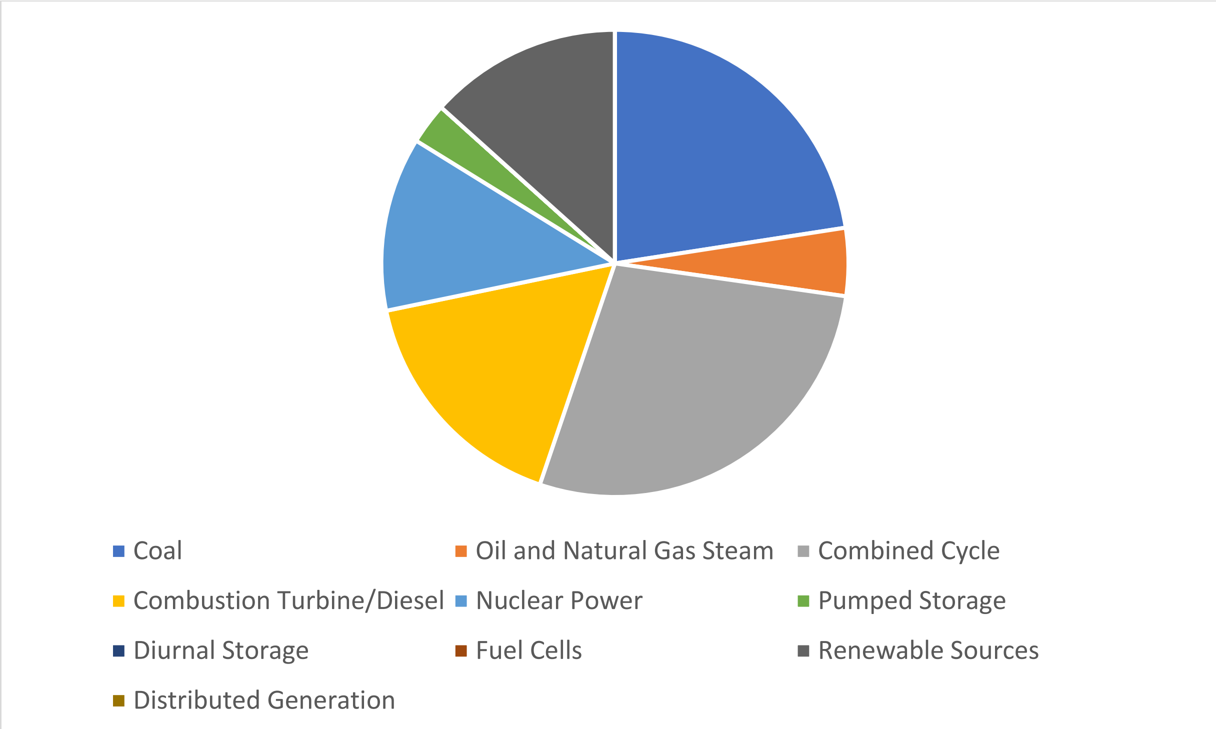

Figure 4 - Net Summer Electric Generating Capacity, SERC-SE Region, 2022[8]

Per-MW capacity replacement values for the three resource types were estimated using information published primarily by the US EIA in conjunction with the 2020 (and subsequent) Annual Energy Outlook[9], with other sources as needed. The information includes overnight capital costs, fuel costs, heat rates, and operations and maintenance (O&M) costs. Table 11 summarizes the plant capacity and energy costs estimated for this analysis. Inputs to these estimates are included in the appendix.

Table 11 - Capacity and Energy Costs by Potential Replacement Resource Type

	Capacity (2023$/kW-year)	**Energy (2023$/MWh)**
Coal	$380.26	$30.79
Combined Cycle Turbine	$86.68	$39.74
Combustion Turbine	$81.81	$60.53

A screening curve analysis is sometimes employed to establish the least-cost mix of replacement resources for foregone capacity. However, the latest published cost estimates summarized in Table 11 establish that of the three resources considered, the two gas-fired plant types would be the only

[8] US EIA, Electric power projections for Electricity Market Module Regions, AEO 2022
[9] US EIA, Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies, 2020.

probable candidates. Further, the capacity and energy costs for the two gas-fired plants imply that combustion turbine generation would comprise a very small amount (likely about 2.7% or 0.6 MW) of the replacement mix. It was therefore assumed that the replacement resource would be combined cycle turbine capacity. Its corresponding capacity value was used to estimate the value of lost hydropower capacity - the “capacity benefits” foregone – under each of the study alternatives.

Table 12 summarizes the value of capacity at the three projects under each of the study alternatives. Capacity impacts of the proposed actions would be very small - 0.08% under Alternatives 2 and 5.

Table 12 - Value of Dependable Capacity

	Hartwell	Russell	Thurmond	System Total	Change from baseline
Baseline	$26,304,196	$39,390,454	$30,222,612	$95,917,262	n/a
Alt. 2	$26,303,434	$39,463,199	$30,231,895	$95,998,528	$81,266
Alt. 5[3]	$26,303,434	$39,463,199	$30,231,895	$95,998,528	$81,266

Summary of Hydropower Benefits Foregone

Table 13 summarizes the total hydropower benefits foregone under each of the study’s alternatives. The results are presented individually in the preceding sections (energy benefits foregone in Table 7, and capacity benefits foregone in Table 12). Because these estimates are based on the equivalent costs of the region’s energy generation and capacity, they simultaneously represent the replacement costs of hydropower.

Table 13 - Summary of Hydropower Impacts

	Energy (MWh)	Energy Revenue (2023$)	Dependable Capacity (MW)	Capacity Revenue (2023$)	Total Revenue (2023$)	Change from Baseline (2023$)	% Change from baseline
Baseline	1,539,038	$46,698,012	1,107	95,917,262	$142,615,274	n/a	
Alt. 2	1,535,153	$46,611,392	1,108	95,998,528	$142,609,920	-$5,354	0.00%
Alt. 5[3]	1,535,153	$46,611,392	1,108	95,998,528	$142,609,920	-$5,354	0.00%

Revenue Impacts

USACE's guidance on estimating the revenue impacts of water supply reallocations is reflected in the following:

> *"Revenues foregone to hydropower are the reduction in revenues accruing to the U.S. Treasury as a result of the reduction in hydropower outputs based on the existing rates charged by the power marketing agency."*[10]
>
> *"The Corps does not market the power it produces; marketing is done by the Federal power marketing agencies (Southeastern Power Administration, Southwestern Power Administration, Western Area Power Administration, and Bonneville Power Administration) through the Secretary of Energy. The rates are set by the marketing agency to: (a) recover costs (producing and transmitting) over a reasonable period of years (50 years usually); and (b) encourage widespread use at the lowest possible rates to consumers, consistent with sound business principles."*[11]

Revenue foregone under each alternative is based on the current SEPA contract rates applicable to power generation by the three impacted hydropower plants. The current rates are:

Energy Rate (Total): $12.80/MWh

Monthly Capacity Charge: $4.04/kW-month

To compute energy revenue foregone, the contract energy rate is applied to the average energy foregone, and the capacity charge is applied to the foregone dependable capacity. Table 14 below summarizes the revenue foregone for each of the alternatives.

Table 14 - PMA Revenue Impacts

	Energy (MWh)	Energy Revenue (2023$)	Dependable Capacity (MW)	Capacity Revenue (2023$)	Total Revenue (2023$)	Change from Baseline (2023$)	% Change from baseline
Baseline	1,539,038	$19,699,686	1,106.6	53,647,849	$73,347,535	n/a	n/a
Alt. 2	1,535,153	$19,649,958	1,107.5	53,693,302	$73,343,260	-$4,275	-0.01%
Alt. 5[3]	1,535,153	$19,649,958	1,107.5	53,693,302	$73,343,260	-$4,275	-0.01%

[10] Engineer Manual ER 1105-2-100, 22 April 2000, "Planning Guidance Notebook", Appendix E – Civil Works, Section VIII – Water Supply, E-57 Other Authorities, (d) Reallocation of Storage, (2) Cost of Storage, (b) Revenue Foregone, page E-217
[11] Engineer Manual ER 1105-2-100, 22 April 2000, "Planning Guidance Notebook", Appendix E – Civil Works, Section VI – Hydroelectric Power, e-46 Special Considerations, b. Coordination Initiatives, (2) Marketing Agencies, page E-175.

PMA Credits

Project costs originally allocated to hydropower are being repaid through power revenues which are based on rates designed by SEPA and the federal PMA to recover allocated costs plus interest within 50 years of the date of commercial power operation. If a portion of available water is reallocated for fish passage purposes, the PMA's repayment obligation must be reduced in proportion to the lost energy and marketable capacity.

Planning Guidance Notebook, Appendix E-57d(3) of ER 1105-2-100 (22 April 2002) states that:

"If hydropower revenues are being reduced as a result of the reallocation, the power marketing agency will be credited for the amount of revenues to the Treasury foregone as a result of the reallocation assuming uniform annual repayment."

Paragraph d(2)(b) states:

"Revenues foregone to hydropower are the reduction in revenues accruing to the Treasury because of the reduction in hydropower outputs based on the Baseline rates charged by the power marketing agency. Revenues foregone from other project purposes are the reduction in revenues accruing to the Treasury based on any Baseline repayment agreements."

ER 1105-2-100 also allows the marketing agency credit for any additional costs above the lost revenue to recover costs of purchased power to meet the obligations of the current power sales contract(s) relating to the marketing of power from the hydro project(s) where storage is being reallocated. The continuation of Appendix E-57d(3), provides the following guidance:

"In instances where Baseline contracts between the power marketing agency and their customer would result in a cost to the Federal Government to acquire replacement power to fulfill the obligations of contracts, an additional credit to the power marketing agency can be made for such costs incurred during the remaining period of the contracts."

In both cases the credit in each year will be based on the revenue foregone or the replacement costs actually incurred (and documented) by the power marketing agency.

Appendix

A. Generation by Contract Block and Month

Table 15 - Generation by Contract Block and Month, 3-Dam System Total, Baseline

	Contract	Peak	Off Peak	Weekend	Total
1	109,447	5,450	(24,751)	48,108	138,253
2	104,888	6,366	(20,753)	45,454	135,955
3	118,603	10,217	(10,917)	54,967	172,870
4	96,436	28,405	1,227	56,213	182,281
5	93,292	14,190	(22,439)	50,104	135,148
6	84,057	8,033	(27,676)	41,842	106,256
7	99,432	6,232	(34,976)	42,221	112,908
8	102,238	6,166	(38,704)	41,749	111,449
9	94,131	3,582	(39,977)	38,016	95,753
10	94,947	987	(38,847)	39,554	96,641
11	100,454	1,858	(32,394)	42,125	112,043
12	113,532	4,303	(26,731)	48,376	139,480
Total	**1,211,459**	**95,789**	**(316,938)**	**548,728**	**1,539,038**

Table 16 - Generation by Contract Block and Month, 3-Dam System Total, Alternative 2 and 5

	Contract	Peak	Off Peak	Weekend	Total
1	109,125	5,429	(25,002)	48,058	137,610
2	104,674	6,426	(20,787)	45,241	135,554
3	117,952	10,151	(10,903)	54,855	172,056
4	96,293	28,140	1,098	56,370	181,900
5	93,383	14,265	(22,777)	50,074	134,946
6	84,387	8,018	(27,885)	41,523	106,044
7	99,454	6,350	(35,172)	42,013	112,645
8	102,064	6,091	(38,816)	41,878	111,218
9	93,975	3,443	(40,326)	38,126	95,218
10	95,233	992	(38,951)	39,565	96,839
11	100,342	1,816	(32,432)	41,715	111,441
12	113,592	4,352	(26,456)	48,195	139,683
Total	**1,210,473**	**95,474**	**(318,409)**	**547,615**	**1,535,153**

B. Dependable Capacity Calculations

Table 17 - Dependable Capacity by Simulated Year, 3-Dam System, Baseline

	Average high demand month weekly generation (MWh)	Potential supportable capacity (MW)	High month average capability	Actual supportable capacity
1939	31,512	1,432	1,282	1,053
1940	36,858	1,669	1,280	1,079
1941	31,294	1,382	1,281	1,072
1942	31,228	1,438	1,281	1,079
1943	35,321	1,672	1,284	1,074
1944	31,096	1,454	1,281	1,070
1945	31,477	1,444	1,281	1,062
1946	31,264	1,457	1,282	1,082
1947	31,101	1,393	1,283	1,099
1948	35,742	1,711	1,284	1,095
1949	51,884	2,654	1,283	1,156
1950	31,079	1,475	1,283	1,088
1951	31,492	1,480	1,282	1,083
1952	31,138	1,469	1,281	1,071
1953	31,181	1,471	1,281	1,067
1954	31,340	1,440	1,284	1,116
1955	29,975	1,301	1,287	1,134
1956	31,422	1,391	1,286	1,156
1957	31,216	1,463	1,283	1,101
1958	32,015	1,549	1,283	1,090
1959	31,413	1,480	1,282	1,082
1960	31,185	1,481	1,282	1,086
1961	33,774	1,624	1,284	1,065
1962	31,363	1,474	1,282	1,080
1963	32,623	1,548	1,283	1,080
1964	37,368	1,752	1,284	1,102
1965	31,253	1,448	1,283	1,103
1966	31,259	1,465	1,282	1,082
1967	36,467	1,775	1,284	1,093
1968	31,136	1,452	1,282	1,082
1969	32,651	1,579	1,285	1,100
1970	31,265	1,429	1,283	1,103
1971	31,250	1,435	1,282	1,079
1972	32,052	1,508	1,286	1,098

1973	33,522	1,601	1,287	1,115
1974	35,187	1,733	1,286	1,107
1975	33,313	1,580	1,283	1,084
1976	34,140	1,611	1,283	1,110
1977	31,586	1,498	1,282	1,090
1978	31,430	1,471	1,282	1,083
1979	34,963	1,709	1,287	1,120
1980	31,371	1,485	1,282	1,083
1981	31,364	1,289	1,286	1,188
1982	31,337	1,463	1,281	1,070
1983	31,142	1,447	1,282	1,070
1984	39,496	1,864	1,284	1,115
1985	31,402	1,484	1,282	1,095
1986	31,080	1,289	1,287	1,167
1987	31,418	1,454	1,283	1,108
1988	31,088	1,295	1,288	1,165
1989	33,924	1,625	1,285	1,106
1990	31,473	1,492	1,281	1,081
1991	36,512	1,796	1,285	1,081
1992	33,044	1,611	1,284	1,079
1993	31,179	1,463	1,282	1,078
1994	48,730	2,389	1,284	1,176
1995	33,660	1,580	1,283	1,085
1996	31,156	1,472	1,281	1,066
1997	31,094	1,465	1,282	1,067
1998	31,547	1,494	1,282	1,062
1999	31,234	1,413	1,285	1,129
2000	31,061	1,263	1,286	1,188
2001	30,960	1,297	1,283	1,174
2002	31,479	1,298	1,282	1,178
2003	37,859	1,864	1,285	1,082
2004	42,160	2,083	1,281	1,146
2005	45,099	2,279	1,283	1,134
2006	30,972	1,363	1,286	1,161
2007	31,175	1,330	1,282	1,174
2008	30,639	1,229	1,276	1,168
2009	31,224	1,368	1,287	1,149
2010	31,203	1,463	1,283	1,089
2011	31,121	1,355	1,283	1,167
2012	31,560	1,350	1,281	1,146
2013	56,301	2,880	1,281	1,195

Table 18 - Dependable Capacity by Simulated Year, 3-Dam Total, Alternative 2 and 5

	Average high demand month weekly generation (MWh)	Potential supportable capacity (MW)	High month average capability	Actual supportable capacity
1939	31,471	1,436	1,282	1,052
1940	36,813	1,670	1,281	1,085
1941	31,309	1,384	1,281	1,075
1942	31,225	1,445	1,281	1,078
1943	34,997	1,669	1,284	1,066
1944	31,087	1,460	1,281	1,070
1945	31,400	1,446	1,281	1,062
1946	31,077	1,457	1,282	1,078
1947	31,111	1,392	1,283	1,107
1948	35,490	1,703	1,285	1,095
1949	51,828	2,666	1,283	1,156
1950	31,086	1,480	1,283	1,088
1951	31,295	1,475	1,282	1,083
1952	31,020	1,468	1,281	1,071
1953	31,163	1,477	1,281	1,067
1954	31,342	1,446	1,284	1,115
1955	31,228	1,355	1,286	1,173
1956	31,274	1,392	1,286	1,151
1957	31,228	1,470	1,283	1,101
1958	32,009	1,556	1,284	1,089
1959	31,444	1,489	1,282	1,082
1960	31,224	1,486	1,283	1,090
1961	33,550	1,609	1,283	1,071
1962	31,372	1,479	1,282	1,080
1963	32,618	1,553	1,283	1,081
1964	36,889	1,739	1,284	1,094
1965	31,262	1,449	1,284	1,107
1966	31,251	1,472	1,282	1,082
1967	36,640	1,792	1,284	1,098
1968	31,177	1,460	1,282	1,082
1969	32,715	1,583	1,285	1,109
1970	31,252	1,434	1,283	1,103
1971	31,241	1,440	1,282	1,079
1972	32,031	1,512	1,286	1,100
1973	33,430	1,607	1,287	1,116
1974	35,326	1,748	1,287	1,109
1975	33,248	1,584	1,283	1,083

1976	34,124	1,618	1,283	1,109
1977	31,520	1,501	1,282	1,090
1978	31,426	1,477	1,282	1,082
1979	34,247	1,690	1,286	1,105
1980	31,364	1,492	1,282	1,082
1981	31,315	1,289	1,286	1,187
1982	31,227	1,461	1,281	1,069
1983	31,181	1,454	1,282	1,072
1984	39,538	1,871	1,284	1,118
1985	31,382	1,490	1,282	1,095
1986	31,066	1,289	1,287	1,168
1987	31,442	1,461	1,282	1,109
1988	31,086	1,295	1,288	1,168
1989	34,208	1,637	1,284	1,118
1990	31,471	1,500	1,281	1,081
1991	36,808	1,812	1,286	1,092
1992	32,976	1,615	1,284	1,079
1993	31,172	1,470	1,282	1,078
1994	48,822	2,404	1,284	1,177
1995	33,564	1,582	1,283	1,084
1996	31,147	1,478	1,281	1,065
1997	31,088	1,472	1,282	1,067
1998	31,539	1,500	1,282	1,063
1999	31,250	1,418	1,285	1,132
2000	31,055	1,262	1,286	1,189
2001	30,790	1,289	1,284	1,172
2002	31,246	1,287	1,281	1,175
2003	38,340	1,892	1,285	1,091
2004	41,941	2,082	1,281	1,144
2005	45,059	2,289	1,283	1,134
2006	30,985	1,368	1,286	1,161
2007	31,234	1,330	1,283	1,178
2008	30,322	1,215	1,278	1,162
2009	30,779	1,361	1,287	1,137
2010	31,194	1,469	1,283	1,089
2011	31,155	1,357	1,283	1,169
2012	31,509	1,349	1,281	1,147
2013	56,065	2,887	1,282	1,195

C. Capacity Value Estimate Inputs

Table 19 - Natural Gas Combined Cycle Turbine Capacity Value Inputs

Input	**Value**
Year of interest	2023
EIA Region	SRSE
Handy-Whitman Region	2
OCC Estimate Year	2019
Overnight Capital Cost ($/kW)	$984.94
Discount rate/Borrowing rate	2.50%
Plant life	40
Depreciation rate	2.5%
Fixed O&M ($/kW/yr)	$14.58
Variable O&M ($/MWh)	$2.45
Fuel cost ($/MWh)	$37.29
Plant Factor	87%
Total Capacity Payment	**$78.44**
Other variables and adjustments:	
Hydro flex value	2.5%
Hydro flex value adjustment	$1.96
Plant mechanical availability	90%
Hydro mechanical availability	98%
Mechanical availability adjustment	$6.28
Total adjustments	**$8.24**
Total Capacity Value ($/kW/yr)	**$86.68**
Total Energy Value ($/MWh)	**$39.74**

Table 20 - Natural Gas Turbine Capacity Value Inputs

Input	**Value**
Year of interest	2023
EIA Region	SRSE
Handy-Whitman Region	2
OCC Estimate Year	2019
Overnight Capital Cost ($/kW)	$942.59
Discount rate/Borrowing rate	2.50%
Plant life	40
Depreciation rate	2.5%
Fixed O&M ($/kW/yr)	$12.92
Variable O&M ($/MWh)	$5.10
Fuel cost ($/MWh)	$55.43

Plant Factor	10%
Total Capacity Payment	**$74.03**
Other variables and adjustments:	
Hydro flex value	2.5%
Hydro flex value adjustment	$1.85
Plant mechanical availability	90%
Hydro mechanical availability	98%
Mechanical availability adjustment	$5.92
Total adjustments	**$7.77**
Total Capacity Value ($/kW/yr)	**$81.81**
Total Energy Value ($/MWh)	**$60.53**

Table 21 - Coal Steam Plant Capacity Value Inputs

Input	**Value**
Year of interest	2023
EIA Region	SRSE
Handy-Whitman Region	2
OCC Estimate Year	2019
Overnight Capital Cost ($/kW)	$4,276.13
Discount rate/Borrowing rate	2.50%
Plant life	40
Depreciation rate	2.5%
Fixed O&M ($/kW/yr)	$45.00
Variable O&M ($/MWh)	$4.99
Fuel cost ($/MWh)	$25.80
Plant Factor	65%
Total Capacity Payment	**$322.25**
Other variables and adjustments:	
Hydro flex value	5.0%
Hydro flex value adjustment	$16.11
Plant mechanical availability	85%
Hydro mechanical availability	98%
Mechanical availability adjustment	$41.89
Total adjustments	**$58.01**

Total Capacity Value ($/kW/yr)	**$380.26**
Total Energy Value ($/MWh)	**$30.79**