Missouri River Recovery Management Plan and Environmental Impact Statement

Hydropower
Environmental Consequences Analysis

Technical Report

August 2018

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
BiOp	2003 Amended Biological Opinion
CO_2	carbon dioxide
EIA	Energy Information Administration
EIS	environmental impact statement
EMM	Electricity Market Module
EPA	U.S. Environmental Protection Agency
EQ	environmental quality
ER	Engineering Regulation
ESA	Endangered Species Act
ESH	emergent sandbar habitat
H&H	hydrologic and hydraulic (model)
HBC	Hydropower Benefits Calculator
HC	human considerations
HEC	Hydrologic Engineering Center - Reservoir System Simulation
LMP	locational marginal pricing
MISO	Midcontinent Independent System Operator
MROW	Midwest Reliability Organization – West
MRRMP-EIS	Missouri River Recovery Management Plan and Environmental Impact Statement
MRRP	Missouri River Recovery Program
NED	national economic development
NERC	North American Electric Reliability Corporation
NOx	oxides of nitrogen
OSE	other social effects
P&G	1983 Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies
POR	period of record
RED	regional economic development
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
SOx	oxides of sulfur
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
WAPA	Western Area Power Administration
WAUE	Western Area – Upper Great Plains East

1.0 Introduction

The Kansas City and Omaha Districts of the U.S. Army Corps of Engineers (USACE), in cooperation with the U.S. Fish and Wildlife Service (USFWS), have developed the Missouri River Recovery Management Plan and Environmental Impact Statement (MRRMP-EIS). The purpose of the MRRMP-EIS is to develop a suite of actions that meets Endangered Species Act (ESA) responsibilities for the piping plover, the interior least tern, and the pallid sturgeon.

The purpose of the Hydropower Environmental Consequences Analysis Technical Report is to provide supplemental information on the hydropower analysis and results in addition to the information presented in the MRRMP-EIS. Additional details on the National Economic Development (NED), Regional Economic Development (RED), and Other Social Effects (OSE) methodology and results are provided in this technical report. No Environmental Quality (EQ) analysis was undertaken for hydropower.

1.1 Summary of Alternatives

The MRRMP-EIS evaluates the following alternatives. A detailed description of the alternatives is provided in Chapter 2 of the MRRMP-EIS.

- **Alternative 1 – No Action.** This is the No Action alternative, in which the Missouri River Recovery Program (MRRP) would continue to be implemented as it is currently, including a number of management actions associated with the MRRP and 2003 Amended Biological Opinion (BiOp) compliance. Management actions under Alternative 1 include creation of early life stage habitat for the pallid sturgeon and emergent sandbar habitat (ESH), as well as a spring pulse for pallid sturgeon. The construction of habitat would be focused in the Garrison and Gavins reaches for ESH (an average rate of 164 acres per year) and between Ponca to the mouth near St. Louis for pallid sturgeon early life stage habitat (3,999 additional acres constructed).
- **Alternative 2 – USFWS 2003 Biological Opinion Projected Actions**. This alternative represents the USFWS interpretation of the management actions that would be implemented as part of the 2003 Amended BiOp Reasonable and Prudent Alternative (USFWS 2003). Whereas Alternative 1 only includes the continuation of management actions USACE has implemented to date for BiOp compliance, Alternative 2 includes additional iterative actions and expected actions that the USFWS anticipates would ultimately be implemented through adaptive management and as impediments to implementation were removed. Considerably more early life stage habitat (10,758 additional acres constructed) and ESH (an average rate of 1,331 acres per year) would be constructed under Alternative 2 than under Alternative 1. In addition, a spring pallid sturgeon flow release would be implemented every year if specific conditions were met. Alternative 2 would also modify System operations to allow for summer flows that are sufficiently low to provide for early life stage habitat as rearing, refugia, and foraging areas for larval, juvenile, and adult pallid sturgeon.
- **Alternative 3 – Mechanical Construction**. The USACE would mechanically construct ESH at an average rate of 332 acres per year distributed between the Garrison, Fort Randall, and Gavins Point Reaches. This amount represents the acreage necessary to meet the bird habitat targets after accounting for available ESH resulting from System operations. The average annual construction amount includes replacing ESH lost to

erosion and vegetative growth, as well as constructing new ESH. An estimated 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 3. There would not be any reoccurring flow releases or pulses implemented under this alternative; however, should new information be learned through Level 1 and 2 studies over the next 9 years suggesting that spring discharges result in stronger aggregation of adult pallid sturgeon at spawning locations or increased reproductive success, a one-time spawning cue test could be implemented to provide additional information to support or refute this hypothesis. At the present time, it is assumed the test release would be similar to the timing, magnitude, duration, and pattern of the spawning cue included as a recurring release under Alternative 6.

- **Alternative 4 – Spring ESH Creating Release**. The USACE would mechanically construct ESH annually at an average rate of 195 acres per year distributed between the Garrison, Fort Randall, and Gavins Point Reaches. This amount represents the acreage necessary to meet the bird habitat targets after accounting for available ESH resulting from implementation of an ESH-creating reservoir release in the spring. Alternative 4 would be similar to Alternative 1 (the No Action alternative), with the addition of a spring release designed to create ESH for the least tern and piping plover. An estimated 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 4.
- **Alternative 5 – Fall ESH Creating Release**. The USACE would mechanically construct ESH annually at an average rate of 253 acres per year distributed between the Garrison, Fort Randall, and Gavins Point Reaches. This amount represents the acreage necessary to meet the bird habitat targets after accounting for available ESH resulting from implementation of an ESH-creating reservoir release in the fall. Alternative 5 is similar to Alternative 1 (the No Action alternative), with the addition of a release in the fall designed to create sandbar habitat for the least tern and piping plover. An estimated 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 5.
- **Alternative 6 – Pallid Sturgeon Spawning Cue**. The USACE would mechanically construct ESH annually at an average rate of 245 acres per year distributed between the Garrison, Fort Randall, and Gavins Point Reaches. In addition, the USACE would attempt a spawning cue pulse every three years in March and May. These spawning cue pulses would not be started and/or would be terminated whenever flood targets are exceeded. An estimated 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 6.

1.2 USACE Planning Accounts

Alternative means of achieving species objectives were evaluated including consideration for the effects of each action or alternative on a wide range of human considerations (HC). Human considerations to be evaluated in the MRRMP-EIS alternatives are rooted in the economic, social, and cultural values associated with the natural resources of the Missouri River. The HC effects evaluated in the MRRMP EIS are required under the National Environmental Policy Act and its implementing regulations (40 CFR Parts 1500–1508). The 1983 Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies (P&G) also served as the central guiding regulation for the economic and environmental analysis included within the MRRMP-EIS. Further guidance that is specific to USACE is described in Engineering Regulation (ER) 1105-2-100, Planning Guidance Notebook, which provides the overall direction by which USACE Civil Works projects are formulated, evaluated, and selected for implementation. These guidance documents describe four accounts that were established to facilitate evaluation and display the effects of alternative plans:

- The NED account displays changes in the economic value of the national output of goods and services expressed in monetary units. Contributions to NED are the direct net benefits that accrue in the planning area and the rest of the nation.
- The RED account registers changes in the distribution of regional economic activity (i.e., jobs and income).
- The EQ account displays non-monetary effect of significant natural and cultural resources.
- The OSE account registers plan effects from perspective that are relevant to the planning process, but are not reflected in the other three accounts. In a general sense, OSE refers to how the constituents of life that influence personal and group definitions of satisfaction, well-being, and happiness are affected by some condition or proposed intervention.

The accounts framework enables consideration of a range of both monetary and non-monetary values and interests that are expressed as important to stakeholders, while ensuring impacts are not double counted. The USACE planning accounts evaluated for thermal power include NED, RED, and OSE.

1.3 Approach for Evaluating Environmental Consequences of the MRRMP-EIS

The conceptual flow chart shown in Figure 1 demonstrates, in a stepwise manner, how changes to the physical conditions of the Missouri River and its floodplain can lead to changes to the objectives associated with hydropower. This figure also shows the intermediate factors and criteria that were applied in assessing consequences to hydropower.

Hydropower has two important connections with the physical components of the Missouri River watershed: river flows/dam releases and reservoir elevations. The type and amount of dam release directly affects the amount of hydropower generated and can be a function of total water stored in the System. In addition, reservoir elevations can influence the efficiency of turbines and hydropower plants, also impacting the levels of hydropower produced at each facility. Reservoir elevations for all the reservoirs describe the water in System storage, which may affect dam releases. Changes in physical conditions could affect the hydropower System performance, including System hydropower generation, load following capability, plant efficiency, reliability to meet peak demands during critical months, and flexibility to perform ancillary services. (Ancillary services are services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such activities may include load regulation, spinning reserve, non-spinning reserve, replacement reserve, dark start, and voltage support.)

All of these potential changes in hydropower performance could affect the amount of surplus power generated, the need to purchase additional power to meet contract obligations, and changes in reliance on thermal power energy sources. These changes could affect energy and capacity values, which are described in EM 1110-2-1701 Hydropower Manual. These values are based on the most likely thermal alternative, utilizing updated thermal cost projections. The energy/capacity price is based on the cost of energy from a combination of thermal generation plant types that would replace the lost energy/capacity from the hydropower plant due to operational and/or structural changes. The value of this energy is associated with its ability to meet demand. For example, higher price generating resources may only be utilized to meet peak demand. Energy and capacity have both regional and seasonal values. It is possible during the peak summer months that low flows may reduce both hydropower and replacement thermal generation.

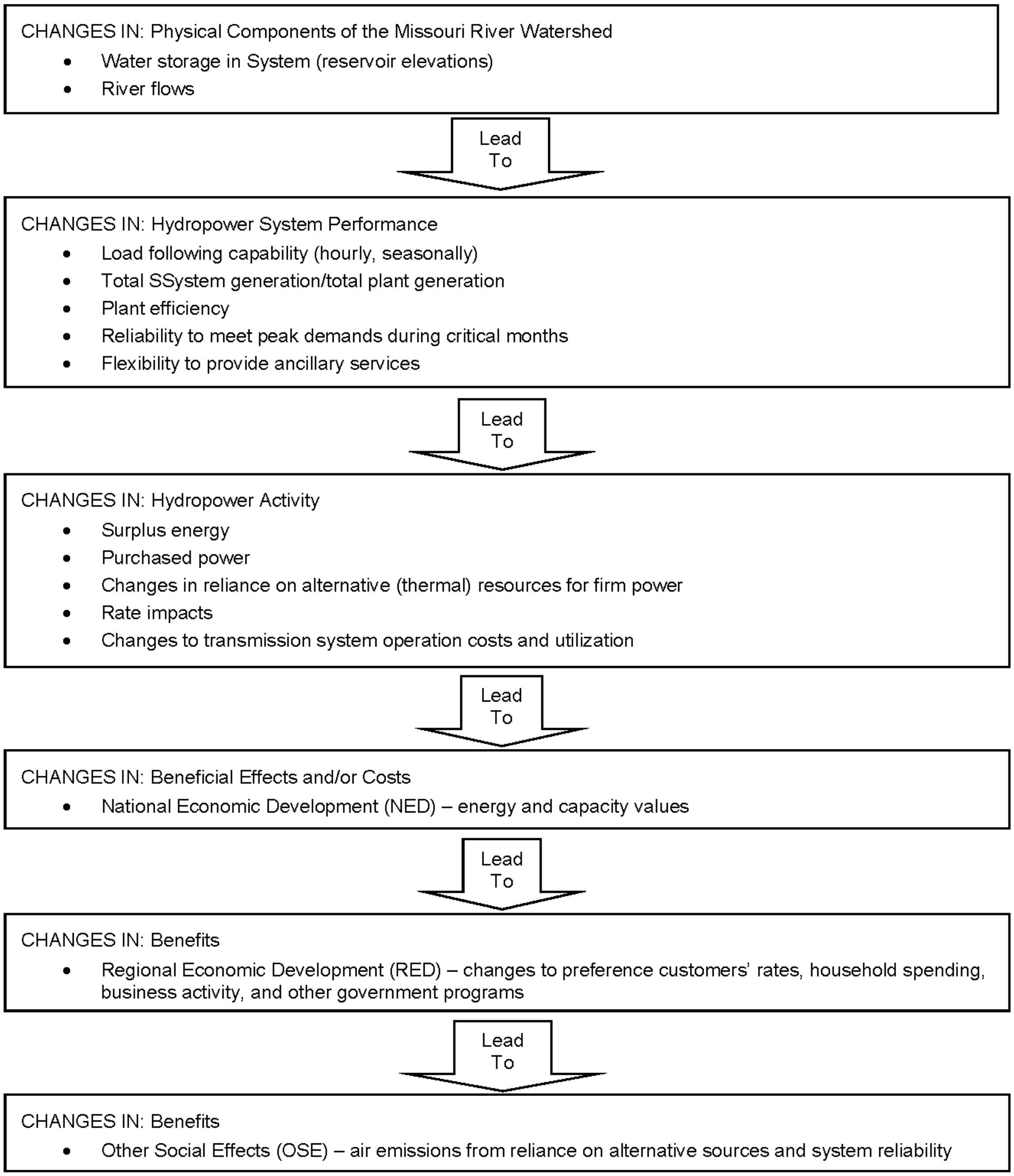

Figure 1. Flow Chart of Inputs Considered in Hydropower Evaluation

Evaluation of the environmental consequences of the MRRMP-EIS requires an understanding of how the physical conditions of the river would change under each of the MRRMP-EIS alternatives. This initial first step is critical for evaluating HC impacts and those specified in the three accounts. Figure 2 shows the overall approach used to evaluate the consequences to hydropower from MRRMP-EIS alternatives.

The following sections provide further details on the methodology.

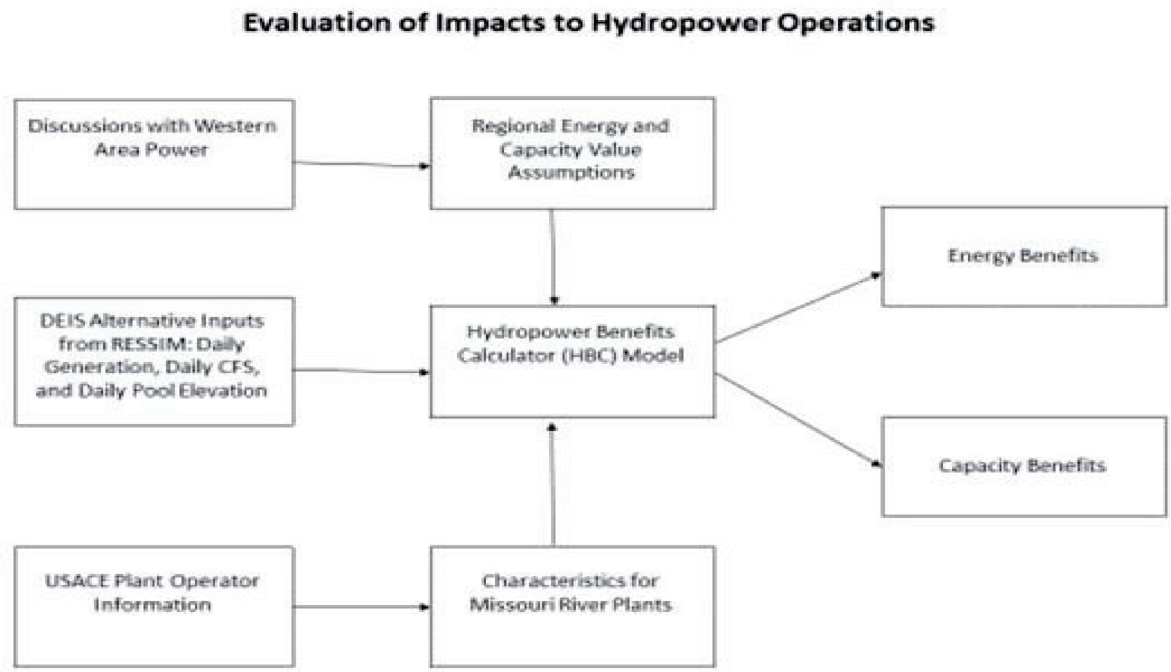

Figure 2. Approach for Evaluating Consequences to Hydropower

The flow chart shows the data necessary to run the Hydropower Benefits Calculator (HBC). This includes discussions with plant operators to get information on plant characteristics and operations and conversations with Western Area Power Administration (WAPA) to determine the appropriate regional energy and capacity value assumptions. This information, along with Hydrologic Engineering Center Reservoir System Simulation (HEC-ResSim) elevation and flow inputs for each of the alternatives, is input into the HBC model. The model then calculates energy benefits and capacity benefits, which can then be compared across alternatives. The outputs from the NED evaluation were used to assess the RED and OSE accounts.

1.4 Assumptions

In modeling the environmental consequences to hydropower from the MRRMP-EIS alternatives, the project team established a set of assumptions. The important assumptions used in the modeling effort are as follows:

- The economic analyses use data from the hydrologic and hydraulic (H&H) modeling of the river and reservoir System. The analysis assumes that the H&H models reasonably estimate river flows and reservoir levels over the 82-year period of record (POR) under each of the MRRMP-EIS alternatives as well as Alternative 1 (the No Action alternative).

- A 2016 estimated Energy Information Administration (EIA) energy price was used in conjunction with the historic pattern of energy prices to determine specific blocks of hourly, daily, and monthly prices. The value was then indexed to 2018. Capacity unit values were determined using a screening curve analysis that plots annual total plant costs for different types of thermal generating plants (fixed capacity cost plus variable operating costs) versus an annual plant factor. The final capacity value is a mix of the least cost alternative sources for each plant factor range. Please see the Energy and Capacity Values section below for more detailed information on the values used in this analysis.
- Some tables presented below were created using spreadsheet software. Arithmetic operations and totals were taken to full decimal accuracy within the spreadsheet. Some tables within this report have been rounded after the mathematical computations were performed; as a consequence, rounded totals may not equal the summation of rounded values.
- The Missouri River HBC model assumes that there is always a market for the power generated. This has the potential to underestimate impacts, in the case where an alternative shifts power production to a time when there isn't a market for the power produced.

2.0 Methodology

2.1 National Economic Development

NED effects are defined as changes in the net value of the national output of goods and services. In the case of hydropower, the conceptual basis for the NED impacts analysis is society's willingness to pay for the increase or decrease in the value of goods attributable to hydropower.

The measurement of national economic effects can be based on estimated changes in energy and capacity values of existing hydropower facilities that would result from MRRMP-EIS alternatives. Replacement energy is computed as the product of energy loss in megawatt-hours and the energy unit value price ($/MWh). Replacement capacity is computed as the product of dependable capacity lost in MW and a capacity unit value ($/MW) representing the value of the most likely thermal alternative. The NED benefits for hydropower are based on the accrued cost of the most likely alternative energy source that would replace reduced hydropower generation (energy and capacity).

The HBC model was used for calculating NED benefits for this study. This model was developed by the USACE's Hydropower Analysis Center in early 2014 for use in Missouri River studies and has been approved for use on Missouri River studies.

The Missouri River HBC model is a post-processor of a flow routing model, daily time step, used to calculate NED hydropower benefits. This model is a series of functions written in the Matlab programming language. The functions themselves are not written specifically for the Missouri River System. Instead the functions read a series of input files that define specific Missouri River characteristics. This provides the user transparency to model parameters, easy adjustment, and adaptability to other systems including the addition of new plants.

Version 1.0 of the Missouri River HBC calculates NED hydropower benefits as defined by the ER 1105-2-100 Planning Guidance Notebook (April 22, 2000) for planning-level studies. The model area focuses on the six USACE dams and their associated reservoirs located on the Missouri River Mainstem, including Fort Peck, Garrison, Oahe, Big Bend, Fort Randall, and Gavins Point.

The model is categorized as a Regional/Local Model as it was conceived to address unique situations and calibrated to specific characteristics for studies related to Missouri River hydropower plants. More details describing a Regional/Local Model can be found in the EC 1105-2-412 entitled, Assuring Quality of Planning Models.

This HBC model acts as a post-processor to the daily time step routing model, HEC-ResSim. Outputs required from the ResSim model include daily flow and reservoir elevations. As the ResSim model simulates MRRMP-EIS alternatives, the HBC model uses this output to compute two NED benefits:

1. Energy Benefits: the product of energy in megawatt-hours and an energy unit value price ($/MWh). The change in megawatt-hours is estimated based upon the change in water elevation and flow between alternatives, while the value of energy benefits is estimated based on the value of energy from a combination of plants that could provide replacement energy.

2. Dependable Capacity Benefits: 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. Dependable capacity benefit is computed as the product of the system's dependable capacity (MW) and a composite unit capacity value ($/MW) that reflects the most likely thermal power generation alternative.

2.1.1 Inputs/Outputs for the HBC Model

The HBC model consists of a number of input files. A brief categorization of these files is given below:

1. Hydrological Inputs – daily flow and reservoir elevations modeled by the HEC-ResSim routing model.

2. Plant System Files – plant characteristics for each of the six Mainstem dams such as turbine efficiency tables, tailwater rating curves, maximum and minimum plant hydraulic capacity including flow limits (USACE 2012).

3. Calibrated Parameters – parameters such as optimization weights and generator efficiency calibrated to minimize error between observed and simulated results (calculated from USACE 2012, Hourly Plant Generation).

4. Economic Inputs – regional energy, capacity, and revenue values. Currently these inputs are created outside of the HBC using Excel® spreadsheets from sources such as Southwest Power Pool (SPP) and the EIA.

The HBC model consists of a number of output files. A brief categorization of these files is given below:

1. Modeled Hydrologic Output: hourly modeled flow, tailwater elevation, and hydraulic head.

2. Modeled Energy Output: hourly modeled generation, turbine efficiency, critical year dependable capacity values, generation roll up tables

3. Benefits Data: modeled plant level dependable capacity tables, energy value roll up tables, revenue foregone rollup tables

4. Calibration Files: performance metrics results for comparing simulated versus observed flow and energy values

5. Model Verification Files: several result files that look at key modeled values to ensure reliability in the calculations.

The HBC model includes the following Matlab functions:

1. Hourly Energy Simulation. Takes hydrological inputs from routing model and shapes average daily flows into hourly values. Hourly generation values are then computed using the power equation. The output from this function is hourly flow and generation values for the modeled POR.

2. Critical Year Hours. This function calculates the number of hours a plant can run at full capability averaged over critical months for a critical year.

3. Dependable Capacity Calculator. This function takes as input the number of hours a plant can run at full capability calculated in the critical_year_hours.m file and computes the plants average capability operating for defined hours during the critical months over the entire modeled POR. Output of this function is each plant's dependable capacity.

4. Energy Benefits Calculator. This function takes as input hourly generation data calculated by the Hourly_Energy_Simulation.m file. The function then distinguishes the generation data into six blocks of decreasing generation values, assigning the respective Energy Replacement Values. Output of this function is monthly roll ups of energy replacement value for each plant.

5. Revenue Foregone Calculator. This function rolls up the hourly data calculated in the Hourly_Energy_Simulation.m file into an annual total generation value. These values are then assigned a constant rate based on the current Power Marketing Administration contracts. The output from this function is the current revenue expected for each modeled year.

2.1.2 Data Collection

The main input to the HBC model consists of daily reservoir elevations and average flows for the six Mainstem dams on the Missouri River, which is provided by the HEC-ResSim routing model. The use of this model requires both historic hydrologic and generation data. The hydrologic data required consists of hourly flow distributions and daily reservoir elevations. The required generation data is hourly generation data. The current version of the HBC model uses six representative years of generation and hydrologic data collected from the USACE Omaha district. Six representative years are considered to reflect current hourly operating patterns.

Additional data is needed for the HBC model. Specific plant level hydropower data requirements include turbine efficiency and tailwater rating curves, which have been collected from the USACE Hydropower Center of Expertise, the Hydropower Design Center. Plant level constraints such as minimum and maximum monthly hydraulic capacity values (upper and lower plant level flow limits) are obtained from Missouri River Water Control Manual.

Economic inputs to the HBC model are readily available from the EIA and SPP websites.

2.1.3 Energy Values

The energy benefits calculator function of the HBC computes annual energy benefits for alternatives. In general, energy benefits are calculated as the product of energy generation and an appropriate energy price in terms of $/MWh. The energy prices used are based on the cost of energy from a combination of generation plants that would replace the lost energy from the hydropower plant due to operational and/or structural changes.

Energy prices vary from hour to hour, between weekdays and weekends, and between different months. One difficulty of computing energy benefits associated with replacing hydropower is associating the lost hourly energy generation with the appropriate replacement energy price. One simplifying assumption is that high hourly energy prices are associated with high hourly generation periods. This assumption is reasonable because economical dispatch during periods of peak demand require adding higher cost generating resources required to meet system load. However, power marketing administrations generate power to meet customer loads that may not completely relate to the overall block load. The HBC does make this simplifying assumption and associates high energy price blocks with high generation blocks. Energy blocks in the HBC model are periods of four hours sorted from high generation periods to low generation periods.

Since energy prices change hourly, daily, and seasonally, quantifying lost hydropower energy benefits requires forecasting when hydropower energy benefits will change and the associated replacement energy pricing variability. The energy values for the Missouri River are best estimated using the Locational Marginal Pricing (LMP) from the Western Area – Upper Great Plains East (WAUE) hub of the SPP. LMP is a computation technique that determines a shadow price for an additional MWh of demand. Historical LMP values for WAUE for 2014 to 2016 were downloaded from the SPP website. Previously, Missouri River studies have used Midcontinent Independent System Operator (MISO) LMP data to estimate energy values for this region. However, in October of 2015, WAPA moved to the SPP market. Unfortunately, this limits the amount of data that includes the Missouri River plants in the estimation of prices. However, given that SPP is the current market, it was deemed as the most appropriate for use in this study. Additionally, values are very similar to those in the MISO market.

Since LMP provides historical pricing it was utilized in combination with information from the EIA to develop an energy price forecast. Each year the EIA publishes an Annual Energy Outlook (AEO) that lists thirty years of forecasted energy costs of different electric market modules. For this study, the 2017 AEO was used to estimate prices. The AEO also lists actual energy prices for three historical years. The energy price forecast is split into three categories; generation, transmission, and distribution. For this study, the EIA generation forecast for the Midwest Reliability Council West was used to forecast future LMP values for this study.

To shape the values the following ratio is assumed:

$$\frac{LMP_{Future}}{LMP_{Past}} = \frac{EIA\_Generation_{Future}}{EIA\_Generation_{Past}}$$

Which can be rewritten as:

$$LMP_{Future} = EIA\_Generation_{Future} * \frac{LMP_{Past}}{EIA\_Generation_{Past}}$$

The future LMP values can then be computed by the product of the EIA generation forecast and a shaping ratio defined as:

$$ShapingRatio = \frac{LMP_{Past}}{EIA\_Generation_{Past}}$$

As explained above, the unique shaping ratio is defined to reflect hourly, weekly, and seasonal variability. Daily LMP values can be sorted from high to low, similar to the sorting of hourly generation. This produces the hourly ranked shaping ratios. Weekly variability is considered by computing shaping ratios for weekends and weekdays. Finally, seasonal variability is taken into account by computing shaping ratios for each month. These shaping ratios are computed as averages with like hourly rankings, month and weekday classification using the equation:

$$ShapingRatio(weekday, month, hourly\_ranking) = Average\left(\frac{LMP_{Past}(weekday, month, hourly\_ranking, year)}{EIA\_Generation_{Past}(year)}\right)$$

The shaping ratios are then averaged for each four-hour block:

$$ShapingRatio_{block=i}(weekday, month) = Average(ShapingRatio(weekday, month, hourly\_ranking))$$

This produces the following equation to compute LMP forecasts for block 1 through 6, weekends, and for each month.

$$LMP_{Future}(block = i, weekday, month) = EIA\_Generation_{Future} * ShapingRatio_{block=i}(weekday, month)$$

It should also be noted that to calculate the average annual energy benefits, the EIA generation 30-year price forecast is annualized to a single number and then applied to the shaping ratios. Table 1 shows the energy prices ($/MWh) used for this analysis.

Table 1. Estimated 2018 Monthly, Weekend and Weekday, and Block Energy Values

Weekday Energy Values												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Block 1	$39.18	$42.95	$34.61	$34.33	$35.61	$39.92	$44.28	$40.85	$30.62	$31.59	$31.17	$30.83
Block 2	$29.90	$33.64	$27.61	$28.37	$31.33	$33.89	$37.48	$34.44	$26.93	$28.35	$26.16	$25.95
Block 3	$26.82	$29.43	$23.76	$25.52	$27.92	$28.19	$31.58	$28.48	$23.48	$25.88	$23.32	$23.32
Block 4	$24.58	$25.82	$21.04	$23.15	$24.41	$22.01	$24.06	$22.02	$19.68	$22.34	$20.72	$21.12
Block 5	$21.50	$22.63	$16.79	$18.00	$17.79	$16.49	$18.20	$17.35	$14.58	$16.18	$16.62	$17.98
Block 6	$18.66	$19.12	$13.27	$13.71	$14.27	$14.02	$16.40	$15.37	$12.02	$13.12	$13.10	$14.84
Weekend Energy Values												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Block 1	$30.88	$34.29	$31.75	$29.08	$31.06	$37.08	$40.21	$37.73	$28.26	$29.79	$27.31	$28.50
Block 2	$25.22	$27.05	$24.97	$24.01	$27.23	$30.69	$33.56	$30.95	$24.40	$25.53	$21.90	$23.00
Block 3	$22.87	$23.40	$21.60	$21.87	$23.96	$25.16	$27.52	$25.10	$20.93	$22.33	$19.88	$20.78
Block 4	$21.05	$21.18	$19.56	$19.26	$19.91	$19.55	$20.40	$19.40	$16.94	$18.98	$17.98	$18.83
Block 5	$19.15	$18.74	$16.18	$14.17	$14.67	$15.53	$16.28	$16.39	$13.94	$15.45	$15.25	$15.19
Block 6	$17.20	$16.75	$13.19	$10.60	$12.33	$13.68	$14.76	$15.34	$12.21	$13.42	$13.30	$12.18

2.1.4 Capacity Values

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. In some cases, even the overload capacity is dependable.

At storage projects, normal reservoir drawdown can result in a reduction of capacity due to a loss in head. At other times, diminished releases during low flow periods may result in insufficient generation to support the marketable capacity of the load. Dependable capacity accounts for these factors by giving a measure of the amount of capacity that can be provided on average during peak demand periods. The capacity analysis intends to capture the costs of building additional resources to maintain the system capacity on average over the long term.

In order to develop a value for capacity, a screening curve analysis that used and computed capacity unit values for coal-fired steam, gas-fired combined cycle, and gas-fired combustion turbine plants were defined using procedures developed by the Federal Energy Regulatory Commission. A screening curve is a plot of annual total plant costs for a thermal generating plant (fixed [capacity] cost plus variable [operating] cost) versus an annual plant factor (plant utilization factor). When this is applied to multiple types of thermal generation resources, the screening curve provides an algebraic way to show which type of thermal generation is the least cost alternative for each plant factor range. In combination with the Missouri River System generation-duration curve, the screening curve produces a composite unit capacity value. The following is an explanation of the steps required to compute the capacity composite unit values.

The screening curve assumes a linear function defined by the following equation:

$$AC = CV + (EV * 0.0876 * PF)$$

where:

AC = annual thermal generating plant total cost ($/kW-year)

CV = thermal generating plant capacity cost ($/kW-year)
EV = thermal generating plant operating cost ($/MWh)
PF = annual plant factor (percent)

Capacity unit values for coal-fired steam, gas-fired combined cycle and combustion turbine plants were computed using procedures developed by FERC. Table 2 shows the average capacity and energy costs for states that lie in the Midwest Reliability Organization – West (MROW) of EIA's Electricity Market Module (EMM) Region.

Table 2. Average Capacity and Energy Costs for MROW EMM

	Coal-fired Steam (CO)	Combined Cycle (CC)	Combustion Turbine (CT)
Adjusted Capacity Value ($/kW-yr)	$327.24	$133.65	$113.19
Operation Costs ($/MWh)	$17.83	$30.43	$44.61

The plot for each thermal generation type was developed by computing the annual plant cost for various plant factors ranging from zero to 100 percent. As shown in the lower section of Figure 3, combustion turbine had the lowest over all capacity cost up to the breakpoint of 16 percent. After that combined cycle had the lowest cost from the plant factor up from 16 percent. Combustion turbine accounts for 1,198 MW of estimated replacement capacity and combined cycle accounts for 1,302 MW of estimated replacement capacity. In this comparison, coal does not become the least cost alternative for any amount of capacity.

The following algorithm is used to compute the composite unit capacity shown in the Table 3.

1. From the cost screening curve, determine the "breakpoints" (the plant factors at which the least cost plant type changes).

2. Find the points on the generation-duration curve where the percent of time generation is numerically identical to the plant factor breakpoints defined in the preceding step; these intersection points define the portion of the generation capacity (MW) that would be carried by each thermal generation plant type.

3. Calculate percent of total generating capacity for each thermal alternative using the proportions defined in Step 2.

4. Calculated the composite unit capacity value of the system as an average of each thermal alternative's capacity cost weighted by their percent of total generating capacity defined in Step 3.

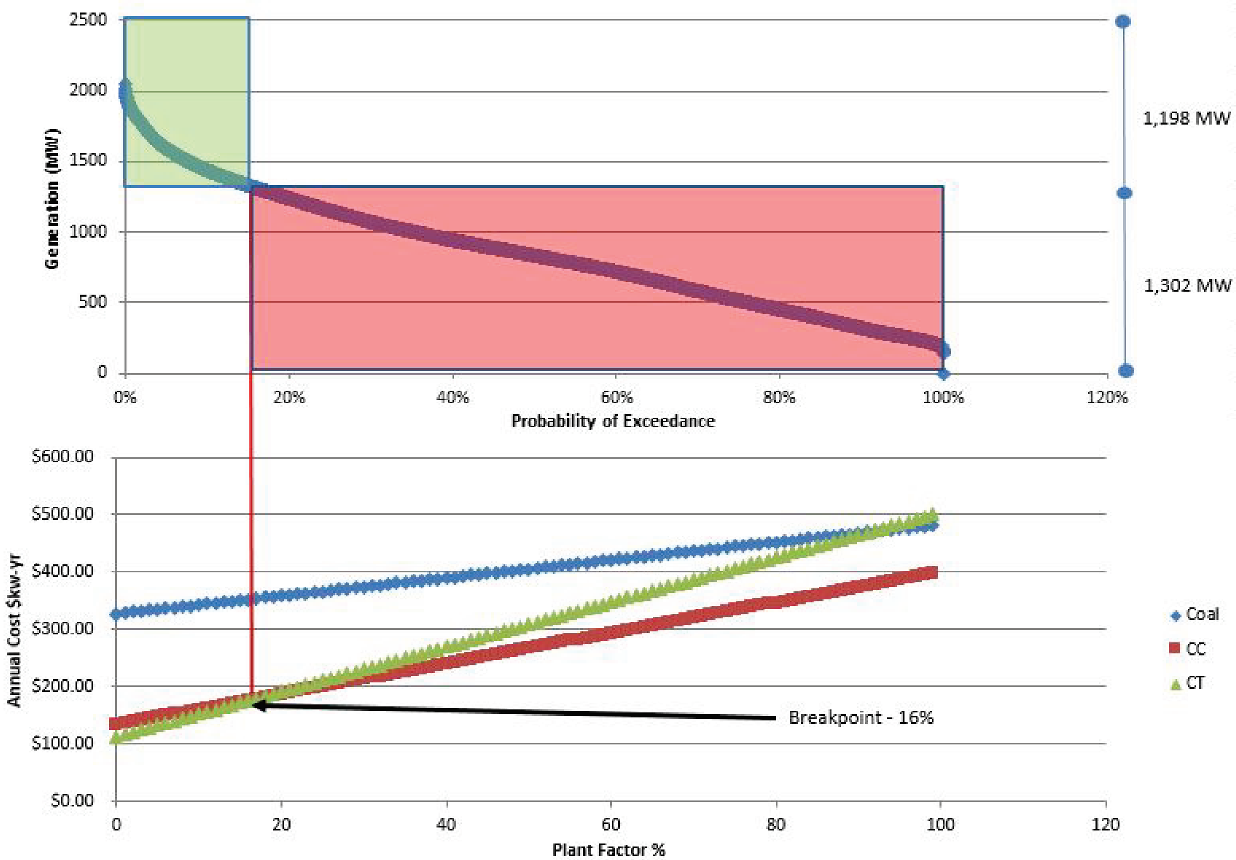

Figure 3. Total System Duration Curve and Regional Screening Curve

Table 3. Composite Capacity Value of Thermal Generating Plants

	Estimated Replacement Capacity (MW)	Percentage of Total Generating Capacity	Capacity Cost ($/KW-yr)	Weighted Value ($)
Combustion Turbine	1198	47.92%	$113.19	$54.24
Combined Cycle	1302	52.08%	$133.65	$69.60
Coal-fired Steam	0	0.00%	$327.24	$0.00
weighted average ($/kW-yr)	–	–	–	$123.85

2.1.5 Calculating Dependable Capacity

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-based power system like the Missouri River Basin is the average availability method. This method is described in Section 6-7g of EM 1110-2-1701, Hydropower Engineering and Design, dated 31 December 1985. The occasional unavailability of a portion of a hydropower project's generating capacity due to hydrologic variations can be treated in the same manner as the occasional unavailability of all or part of a thermal plant's generating capacity due to forced outages.

There are two components in calculating dependable capacity using the average availability method. The first component is the number of hours in a day a plant can run at full capability during a critical water year. This number represents the lower bound estimate of a plant's daily contribution in meeting the peak energy demand. The second component is the plant's actual capability over the hours calculated. The plant's capability over the defined hours can be less than the rated capacity if there are restrictions in flow less than the plant's full hydraulic capacity, or if storage in the System has been depleted, reducing reservoir elevations and consequently hydraulic head.

2.1.5.1 Estimating Hours at Full Capability for Critical Water Year

As explained above, the first component of calculating dependable capacity is estimating the number of hours in a day a plant can run at full capability in a critical water year (critical hours at full capability). This is done for periods of the year when customer demands are high and water availability may be restricted. Conversations with WAPA suggested two critical periods: a summer period from July through August and a winter period from December through January.

For power marketing purposes, WAPA defines the critical water year for the Missouri River plants as 1961. Historically this represents one of the worst adverse water inflow years on record excluding the years 1934–1942. Alternatives for this study include a much longer POR spanning from 1931 to 2012. For the purposes of this study, new critical water years consistent with the POR modeling were developed for this analysis.

The new critical water years were developed by creating a probability of exceedance curve for the total generation for the critical months defined above. These were identified as 1937 for the winter critical period and 2007 for the summer critical period in Alternative 1 (the No-Action Alternative). Critical years are defined as the year that corresponds to the 95 percent exceedance probability of the total generation.

2.1.5.2 Equations Used in Computing Critical Hours at Full Capability

The HBC model calculates the daily hours at full capacity (Hours_At_Cap) number for all weekdays in the critical year and critical months. This is done using the following calculations:

$$1)\ \text{Volume\_total (Daily)} = \text{Average\_Flow (Daily)} * 24 * 60 * 60$$

$$2)\ \text{Volume\_Required(Daily)} = \text{Min\_Flow (Hourly)} * 24 * 60 * 60$$

$$3)\ \text{Volume\_Flex} = \min(0, \text{Volume\_total (Daily)} - \text{Volume\_Required(Daily)})$$

$$4)\ \text{Volume\_To\_Cap (Hourly)} = (\text{Max\_Flow(Hourly)} - \text{Min\_Flow(Hourly)}) * 60 * 60$$

$$5)\ \text{Hours\_At\_Cap(Daily)} = \text{Volume\_Flex/Volume\_To\_Cap}$$

$$6)\ \text{Hours\_At\_Cap} = \text{average(Hours\_At\_Cap(daily)) over the critical year and months}$$

To ensure the critical_year_hours.m function is working as intended the model outputs two files that can be used to check calculations:

Plant_name_peak_hours_mat_CY.txt: plant level hours on peak calculation matrix.

Critical marketable_capacity.txt: annual average capability and hours on peak for all plants for the critical year using a baseline alternative.

Once the critical hours at full capability are determined using a baseline alternative, the HBC model can then calculate a plant's dependable capacity for all alternatives.

The HBC model calculates a daily dependable capacity for all weekdays in the critical months over the entire POR. This is done using the following calculations:

$$
\begin{aligned}
&1)\ \text{Volume\_total (Daily)} = \text{Average\_Flow (Daily)} * 24 * 60 * 60 \\
&2)\ \text{Volume\_Required(Daily)} = \text{Min\_Flow (Hourly)} * 24 * 60 * 60 \\
&3)\ \text{Volume\_Flex(Daily)} = \min(0, \text{Volume\_total (Daily)} - \text{Volume\_Required(Daily)}) \\
&4)\ \text{Volume\_Flex(Hourly)} = \text{Volume\_Flex(Daily)/Hours At Cap} \\
&5)\ \text{Flow\_Flex(Hourly)} = \text{Volume\_Flex(Hourly)}/(60 * 60) \\
&6)\ \text{If Flow\_Flex(Hourly)} + \text{Min\_Flow (Hourly)} > \text{Max\_Flow (Hourly)} \\
&\qquad\qquad \text{Peak\_FLow} = \text{Max\_Flow (Hourly)} \\
&\quad \text{Else} \\
&\qquad\qquad \text{Peak\_FLow} = \text{Min\_Flow (Hourly)} + \text{Flow\_Flex(Hourly)} \\
&7)\ \text{Capability(daily)} = \text{Head(daily)} * \text{Peak\_Flow} * \text{efficiency(daily)}/11800
\end{aligned}
$$

A plant's dependable capacity is the average of the capability (daily) during the critical months over the period of record.

2.1.6 Limitations of the Modeling and Assumptions

Reductions in renewable hydropower generation would be costly for power cooperatives and rural customers. Typically, when WAPA cannot generate enough hydropower to fulfill its contractually obligated agreements, they must go on the open market and purchase electricity, typically at higher costs. The NED modeling is attempting to estimate the national economic impact of these potential alternatives. However, the impacts illustrated in the results are likely underestimating the total impact of these alternatives. In addition, there could be impacts to ancillary services, reliability, and grid stability, which could be affected under the alternatives. Additional evaluation may result in more adverse impacts under some of the alternatives; however, it would not change the relative ranking of the alternatives compared to Alternative 1. Given the considerable additional analysis required for analyzing these impacts and the likelihood that the modeling would not impact the selection of the preferred alternative, additional evaluation on energy prices, ancillary services, and electricity reliability was not undertaken. Additional information examining the potential for coupled effects from impacts to both hydropower and thermal power is included in Section 6.0.

2.2 Regional Economic Development

The RED evaluation uses the output of the NED evaluation to estimate the changes in electricity supplied and/or wholesale electricity rates for preference customers as a result of changes in hydropower production. If there are changes in the hydropower energy generated or capacity due to MRRMP-EIS alternatives, it could lead to changes in electricity supplied or electricity rates, which could affect customer's household spending or business activity. The generation provided by the HBC model is used in the RED evaluation. The RED evaluation uses the hourly load (demand) experienced by WAPA in an attempt to estimate the direct financial impact to WAPA.

The RED benefits for hydropower are based on the results of the NED analysis. WAPA markets its firm power from the hydropower plant to various preferred customers who meet federally mandated criteria. In general, power is marketed to meet the customer's hourly needs. Changes to overall System operations may affect the ability for WAPA to meet these firm demands. Sales of electric power must repay all costs associated with power generation. Under the Reclamation Project Act of 1939, WAPA must establish power rates sufficient to recover operating, maintenance and purchase power expenses and repay the federal government's investment within 50 years for building these generation and transmission facilities. Rates must also be set to cover certain non-power costs Congress has assigned to power users to repay, such as irrigation costs in excess of water users' ability to repay, interest expenses on the unpaid balance of power-related principal and replacement of power facilities within the expected service life of the replacement (Western 2011). WAPA conducts annual power repayment studies to ensure power rates for each project are adequate. Data in the study include historic expenses and investments already repaid from power revenues as well as projections for future years. Also listed is estimated annual repayment of generation and transmission investment costs throughout the repayment period of the project. More specifically, the studies detail year-by-year revenues and expenses, estimated amounts of investment and interest to be paid each year and the total amount of investment remaining to be repaid. Historical data is gathered primarily from accounting records through the last fiscal year. In addition to WAPA marketing and billing records, generation, hydrology and project data, historical and projected figures are provided by the Bureau of Reclamation, the USACE and the International Boundary and Water Commission. Since the amount of energy generated is based on the current hydrology of the System, accurate annual water supply forecasting is important in establishing the proper rate value.

As cooperatives, municipalities, and other preference customers receive their allocation from WAPA, the cooperative and other customers benefit from the relatively low-cost source of hydropower energy, providing rates lower than other for profit electric utilities. If the rates for repayment that WAPA charges its preferred customers need to be increased to cover an increase in costs, these low-cost benefits for preferred customers would decrease and would account for the RED impact. The USACE worked with WAPA to obtain reasonable estimates of the financial impact of each alternative, which would in turn affect rates.

The pricing used in this estimate was based on actual October 2015 through June 2016 average SPP LMP pricing at USACE generators in the SPP footprint for on- and off-peak periods.

2.3 Other Social Effects

An environmental benefit associated with hydropower generation is avoided air emissions. In general, electricity generated from a hydropower resource is considered a low emission-producing resource when compared to thermal alternatives because no fuels are actually burned. Without the generation of electricity from hydropower sources, power would likely come from a fossil fuel source, such as a coal-fired or natural gas power plant. Therefore, a reduction in hydropower generation could result in an increase in air emissions due to a greater reliance on fossil fuel power generation in meeting system demand. Since different regions have different electricity-generating resource mixes, the avoided emissions factor is dependent on the region and available alternative sources of electric generation. This factor may also be seasonally or even hourly dependent as different mixes of electricity-generating resources are required to meet demand.

The primary inputs for this analysis are from the HBC model, described in detail in the NED hydropower evaluation. This model will produce monthly and annual average energy generation for each alternative. Electricity generation under the NED hydropower evaluation will be multiplied by a regional emission rate to compute the change in air emissions.

The change in benefits of a particular alternative is based on the difference in electricity generation when compared to existing conditions. For example, a positive difference from existing conditions implies an increase in annual generation, while a negative difference implies a decrease in average annual electricity generation. The decreases in hydropower generation are assumed to be met with alternative sources of energy within the region and are multiplied by the average rate of emissions provided by replacement sources of energy.

The factors used to calculate the increased or decreased emissions depend on what mix of resources would replace the hydropower production. Since different regions have different generating resource mixes, this factor is regionally dependent. The Environmental Protection Agency's (EPA's) eGRID is a comprehensive database of environmental attributes of electric power systems, incorporating data from several federal agencies. One field of data stored in the eGRID database is emission rates for 26 eGRID subregions. These regions are contained within a single North American Electric Reliability Corporation (NERC) region with similar emissions and generating resource mixes. Emission rates from the eGRID database are defined as pounds per MWh for greenhouse gases: CO_2, methane, NO, and CO_2 equivalent. These can be further divided into baseload and non-baseload generating resources. Since hydropower is used to replace the generating resources on the margin in this region, this study uses the non-baseload emission rates. The appropriate subregion for this study is the MROW, where the most recent database (2016) emissions factors are 1,822 lbs/MWh for carbon dioxide, 0.154 lbs/MWh or methane, 0.029 lbs/MWh for nitrous oxide, and 1,834 for carbon dioxide equivalent.

The OSE evaluation used EPA guidance for valuing the social cost of carbon. EPA has developed an estimated cost index for the social cost of carbon. The technical support documentation on the Social Cost of Carbon for Regulatory Impact Analysis (EPA, 3) states that:

> Executive Order 12866 requires agencies, to the extent permitted by law, 'to assess both the costs and the benefits of the intended regulation, and recognizing that some costs and benefits are difficult to quantify, propose, or adopt a regulation only upon a reasoned determination that that the benefits of the intended regulation justify its costs.' The purpose of the social cost of carbon estimates presented here is to allow agencies to incorporate the social benefits of reducing carbon dioxide emissions into cost-benefit analyses of regulatory actions. The social cost of carbon is the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change.

The OSE evaluation estimates the social cost of carbon using cost ranges that vary based on the discount rate, the year, and probability of impacts in the future. For this evaluation, a range of social cost of carbon values based on different scenarios (year and probability) was used to demonstrate the potential range of potential impacts including average estimates and 95th percentile (a low probability, high-consequence scenario), all using a 3 percent discount rate. Social cost of carbon values are published in 2007 values and were indexed to 2018 values using the gross domestic product (Chained) Price Index for this evaluation. The 2018 price level values used in this evaluation were the average estimates for 2018 ($48), 2035 ($66), and 2050 ($82) and the 95 percent estimates for 2018 ($138), 2035 ($200), and 2050 ($253) per metric ton of carbon.

The total social cost of carbon was estimated by multiplying the total CO_2-equivalent air emissions by the values described above. The final result of this evaluation provides the estimated social cost of carbon for the three representative years at each probability. The focus of the evaluation was on the change in air emissions and social costs of carbon-equivalent emissions relative to Alternative 1 (the No Action alternative).

3.0 National Economic Development Evaluation Results

The NED analysis for hydropower focused on the changes in generation (replacement energy) and dependable capacity as a result of the changing physical conditions along the Missouri River. The impacts to hydropower present the average annual change in the generation and dependable capacity value over the POR.

3.1 Summary of National Economic Development Results

Table 4 summarizes the overall NED impact of each alternative on hydropower in the Missouri River System. Alternative 4 has the largest change from Alternative 1 (the No Action alternative), resulting in an average annual decrease of almost $3.8 million to hydropower, including impacts on both generation and dependable capacity. Total average annual impacts range from $204,000 (0.04 percent) under Alternative 3 to -$3,771,000 (-0.77 percent) under Alternative 4.

3.2 Alternative 1 – No Action

Under the Alternative 1, the MRRP would continue to be implemented as it is currently. This includes management actions that are in compliance with the BiOp, including the implementation of the spring plenary pulse. The NED analysis for Alternative 1 is summarized by dam in Table 5. Average annual generation under Alternative 1 for the system is 8,721,079 MWh. The average annual value of this generation is $229.1 million The average dependable capacity in summer is 2,115.8 MW, with a value of $262,042,000. The average dependable capacity in winter is 1,859.9, with a value of $230,346,000. The overall value of the system, including generation and dependable capacity – summer, is $491,099,000.

Table 4. Estimated National Economic Development Costs of MRRMP-EIS Alternatives to Hydropower (FY18 Price Level)

NED Measure	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6
Average Annual Generation (MWh)	8,721,079	8,715,670	8,727,115	8,660,832	8,701,949	8,679,355
Average Annual Generation Value	$229,057,000	$228,855,000	$229,167,000	$227,258,000	$228,379,000	$227,796,000
Difference in Average Annual Generation Value		-$202,000	$110,000	-$1,800,000	-$678,000	-$1,261,000
Average Annual Dependable Capacity Value - Summer	$262,042,000	$261,483,000	$262,176,000	$260,935,000	$261,849,000	$260,480,000
Difference in Average Annual Dependable Capacity Value - Summer		-$559,000	$134,000	-$1,107,000	-$193,000	-$1,562,000
Average Annual Dependable Capacity Value - Winter	$230,346,000	$227,929,000	$230,605,000	$228,760,000	$230,174,000	$228,922,000
Difference in Average Annual Dependable Capacity Value - Winter		-$2,418,000	$259,000	-$1,587,000	-$172,000	-$1,424,000
Maximum Average Annual Capacity Loss		-$2,896,000	$94,000	-$1,972,000	-$353,000	-$1,949,000
Total Average Annual Value	$491,099,000	$488,001,000	$491,303,000	$487,328,000	$490,068,000	$487,889,000
Change from Alternative 1		-$3,098,000	$204,000	-$3,771,000	-$1,031,000	-$3,210,000
Percent Change from Alternative 1		-0.63%	0.04%	-0.77%	-0.21%	-0.65%

*Either winter or summer dependable capacity is used to calculate the impacts depends on which season incurs the greater impact for that particular alternative at each individual dam.

Table 5. Summary of National Economic Development Analysis for Alternative 1 (FY18 Price Level)

	Fort Peck	Garrison	Oahe	Big Bend	Fort Randall	Gavin's Point	Total
Average Annual Generation (MWh)	931,701	2,095,254	2,320,134	960,864	1,686,206	726,921	8,721,079
Average Annual Generation Value	$22,932,000	$53,796,000	$62,931,000	$28,973,000	$43,014,000	$17,411,000	$229,057,000
Average Annual Dependable Capacity - Summer (MW)	178.3	442.3	579.2	459.7	340.7	115.5	2,115.8
Average Annual Dependable Capacity Value - Summer	$22,086,000	$54,779,000	$71,733,000	$56,936,000	$42,201,000	$14,307,000	$262,042,000
Average Annual Dependable Capacity - Winter (MW)	189.8	435.0	469.6	381.4	276.0	108.1	1,859.9
Average Annual Dependable Capacity Value - Winter	$23,508,000	$53,872,000	$58,160,000	$47,233,000	$34,183,000	$13,391,000	$230,347,000
Total Average Annual Value - Generation plus Capacity (Summer)	$45,018,000	$108,575,000	$134,664,000	$85,909,000	$85,215,000	$31,718,000	$491,099,000

3.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

The NED analysis for Alternative 2 is summarized by plant in Table 6. This alternative represents the USFWS interpretation of the management actions that would be implemented as part of the 2003 Amended BiOp Reasonable and Prudent Alternative (USFWS, 2003). The average annual generation under this alternative is 8,715,670 MWh, a decrease of 5,409 MWh, when compared with Alternative 1 (the No Action alternative). This equates to a decrease in average annual generation value of $202,000 compared to Alternative 1.

The average annual summer dependable capacity is 2,111.3 MW, a decrease of 4.5 MW compared to Alternative 1. The average annual winter dependable capacity is 1,840.4 MW. The maximum average annual decrease to dependable capacity is $2,896,000. This was determined by looking at each individual plant and determining which season had the greatest impact on that individual plant under that alternative. Each plant's maximum impact was then summed to show the maximum average annual impact on capacity. This value is also used to estimate the total NED value for a given alternative.

The overall reduction in average annual NED value of Alternative 2 as compared to Alternative 1 is $3,098,000 in hydropower generation and dependable capacity. This is a reduction of 0.63 percent of the overall system value calculated under Alternative 1. Approximately 51 percent of the overall reduction is attributable to reduction in generation and dependable capacity at Oahe Dam. An additional 31 percent of the overall reduction is occurring at Big Bend and Fort Peck.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 4 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 2 as compared to Alternative 1. The differences are plotted and color coded based on the type of release occurring each year. The graphic is showing that all years with full release plus low summer flows under this alternative result in years with reduced generation and capacity values. This is also true of some of the eliminated release years. The partial release years are showing a mix between years with lower value and years with higher value relative to Alternative 1. However, the greatest overall negative impact is occurring in a full release year, 1988. Given that the critical period for summer capacity is July and August during the low summer flow period, the impact to capacity is driving these results in the full release years. In some cases, there may be a net generation increase for the year, but the capacity is showing a decrease.

In 32 of the 82 years in the POR, Alternative 2 would result in a higher hydropower value than Alternative 1. The average increase in these years is $8,706,781. In 50 of the years, Alternative 2 results in a lower hydropower value than Alternative 1. The average decrease in these years would be $6,806,200. The entire POR differences between Alternative 2 and Alternative 1 range from a gain of $101,807,000 in 1983 to a loss of $66,786,000 in 1988.

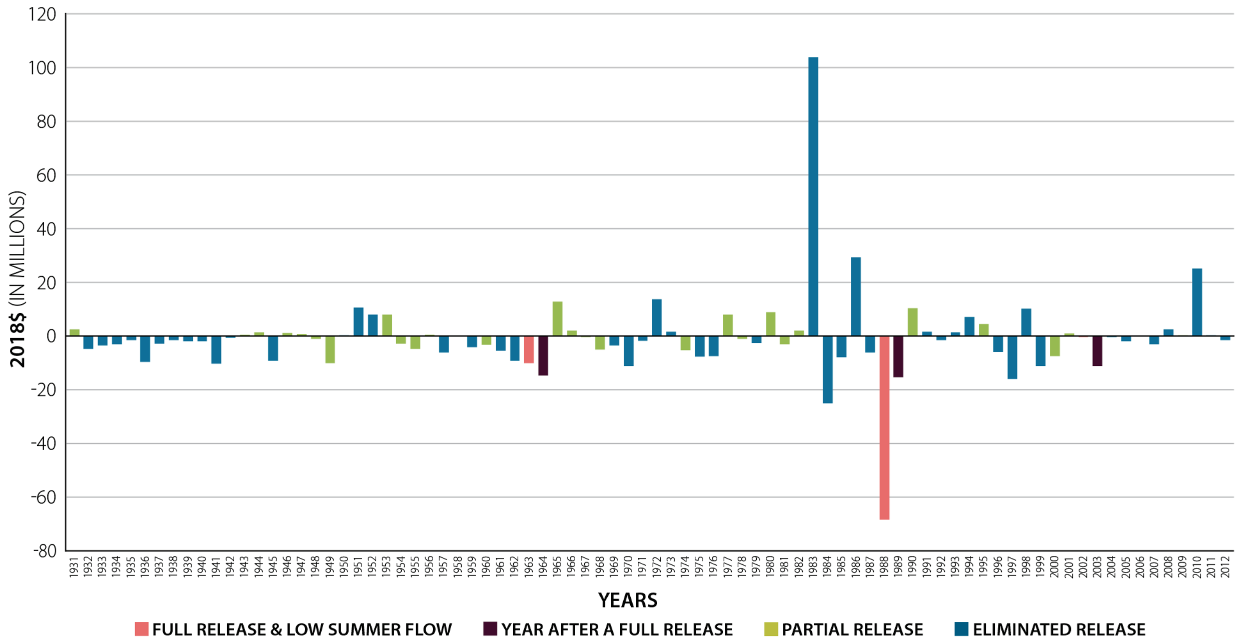

Figure 4. Annual Difference in Value of Alternative 2 Relative to Alternative 1 for Hydropower System Value

Table 6. Summary of National Economic Development Analysis for Alternative 2 (FY18 Price Level)

NED Measure	Fort Peck	Garrison	Oahe	Big Bend	Fort Randall	Gavin's Point	Total
Average Annual Generation (MWh)	932,015	2,094,990	2,309,527	961,878	1,689,137	728,123	8,715,670
Generation Difference from Alternative 1 (MWh)	314	-264	-10,607	1,014	2,931	1,202	-5,409
Average Annual Generation Value	$22,904,000	$53,839,000	$62,683,000	$28,938,000	$43,088,000	$17,402,000	$228,854,000
Difference in Average Annual Generation Value from Alternative 1	-$28,000	$43,000	-$248,000	-$35,000	$74,000	-$9,000	-$203,000
Average Annual Dependable Capacity - Summer (MW)	174.9	440.2	578.6	460.9	341.1	115.7	2,111.3
Difference in Average Annual Dependable Capacity - Summer from Alternative 1 (MW)	-3.4	-2.1	-0.6	1.1	0.3	0.2	-4.5
Average Annual Dependable Capacity Value - Summer	$21,661,000	$54,515,000	$71,657,000	$57,076,000	$42,243,000	$14,331,000	$261,483,000
Difference in Average Annual Dependable Capacity Value - Summer from Alternative 1	-$425,000	-$264,000	-$76,000	$140,000	$42,000	$24,000	-$559,000
Average Annual Dependable Capacity - Winter (MW)	189.5	433.6	458.9	377.6	273.0	107.8	1,840.4
Difference in Average Annual Dependable Capacity - Winter from Alternative 1 (MW)	-0.3	-1.4	-10.7	-3.8	-3.0	-0.3	-19.5
Average Annual Dependable Capacity Value - Winter	$23,473,000	$53,696,000	$56,832,000	$46,761,000	$33,812,000	$13,354,000	$227,928,000
Difference in Average Annual Dependable Capacity Value - Winter from Alternative 1	-$35,000	-$176,000	-$1,328,000	-$472,000	-$371,000	-$37,000	-$2,419,000
Maximum Average Annual Capacity Loss	-$425,000	-$264,000	-$1,328,000	-$472,000	-$370,000	-$37,000	-$2,896,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	-$453,000	-$221,000	-$1,576,000	-$507,000	-$296,000	-$46,000	-$3,099,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	-1.01%	-0.20%	-1.17%	-0.59%	-0.35%	-0.15%	-0.63%

3.4 Alternative 3 – Mechanical Construction Only

Management actions included under Alternative 3 would include those that focus on the creation of ESH through mechanical means. This alternative would have a small, positive impact on hydropower generally associated with the elimination of the spring plenary pulse under Alternative 3.

The one-time spawning cue test (Level 2) release that may be implemented under Alternative 3 was not included in the hydrologic modeling for these alternatives because of the uncertainty of the hydrologic conditions that would be present if implemented. Hydrologic modeling for Alternative 6 simulates reoccurring implementation (Level 3) of this spawning cue over the wide range of hydrologic conditions in the POR. Therefore, the impacts from the potential implementation of a one-time spawning cue test release would be bound by the range of impacts described for individual releases under Alternative 6.

The NED analysis for Alternative 3 is separated by plant and summarized in Table 7. The average annual generation under this alternative is 8,727,115 MWh, an increase of 6,037 MWh, when compared with Alternative 1 (the No Action alternative). This equates to an increase in generation value of $110,000. Under this alternative, the reductions in generation are occurring during high value times of the year, and the gains are occurring during low value times of the year, which is why the overall value of this generation is relatively low.

The average annual summer dependable capacity is 2,116.9 an increase of 1.1 MW compared to Alternative 1. The average annual winter dependable capacity is 1,862.0, an increase of 2.1. The maximum average annual impact to dependable capacity, in this case the smallest increase relative to Alternative 1, is $93,000. This was determined by looking at each individual plant and determining which season had the greatest adverse impact on that individual plant under that alternative. Each plant's maximum negative impact was then summed to show the maximum average annual impact on capacity. This value is also used to determine the total impact assigned to a given alternative.

The overall impact of Alternative 3 as compared to Alternative 1 is a gain of $203,000 which includes a small gain to generation and to dependable capacity in critical periods. This is a gain of 0.04 percent of the overall system value calculated under Alternative 1. Losses are occurring at Big Bend and Fort Randall, while overall gains are occurring at Fort Peck, Garrison, Gavins Point and Oahe. Adverse impacts to hydropower in some years under this alternative are the lowest of any of the alternatives analyzed, when compared to Alternative 1.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 5 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 3 as compared to Alternative 1. The differences are not plotted and color coded based on the type of release year, since Alternative 3 does not have different types of new releases. The graphic is simply showing the annual differences between Alternative 3 and Alternative 1.

In 50 of the 82 years in the POR, Alternative 3 would result in a higher hydropower value than Alternative 1. The average increase in these years would be $775,860. In 32 of the years, Alternative 3 would result in a lower hydropower value than Alternative 1. The average decrease in these years would be $585,313. The entire POR differences range from a reduction of $3,199,000 in 1947 to an increase of $6,585,000 in 1965, compared to Alternative 1.

Table 7. Summary of National Economic Development Analysis for Alternative 3 (FY18 Price Level)

NED Measure	Fort Peck	Garrison	Oahe	Big Bend	Fort Randall	Gavin's Point	Total
Average Annual Generation (MWh)	932,337	2,097,593	2,322,472	960,894	1,685,805	728,014	8,727,115
Generation Difference from Alternative 1 (MWh)	636	2,339	2,338	30	-401	1,094	6,037
Average Annual Generation Value	$22,945,000	$53,849,000	$62,964,000	$28,972,000	$42,999,000	$17,438,000	$229,167,000
Difference in Average Annual Generation Value from Alternative 1	$13,000	$53,000	$33,000	-$1,000	-$15,000	$27,000	$110,000
Average Annual Dependable Capacity - Summer (MW)	178.4	442.7	579.7	459.7	340.8	115.5	2,116.9
Difference in Average Annual Dependable Capacity - Summer from Alternative 1 (MW)	0.10	0.37	0.55	-0.03	0.08	0.01	1.08
Average Annual Dependable Capacity Value - Summer	$22,099,000	$54,825,000	$71,801,000	$56,933,000	$42,211,000	$14,308,000	$262,177,000
Difference in Average Annual Dependable Capacity Value - Summer from Alternative 1	$13,000	$46,000	$68,000	-$3,000	$10,000	$1,000	$135,000
Average Annual Dependable Capacity - Winter (MW)	190.0	435.0	470.9	381.8	276.1	108.1	1,862.0
Difference in Average Annual Dependable Capacity - Winter from Alternative 1 (MW)	0.2	0.1	1.3	0.4	0.1	0.0	2.1
Average Annual Dependable Capacity Value - Winter	$23,527,000	$53,880,000	$58,325,000	$47,286,000	$34,197,000	$13,391,000	$230,606,000
Difference in Average Annual Dependable Capacity Value - Winter from Alternative 1	$19,000	$8,000	$165,000	$53,000	$14,000	$0	$259,000
Maximum Average Annual Capacity Loss	$12,000	$7,000	$68,000	-$4,000	$10,000	$0	$93,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	$25,000	$60,000	$101,000	-$5,000	-$5,000	$27,000	$203,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	0.056%	0.055%	0.075%	-0.006%	-0.006%	0.085%	0.041%

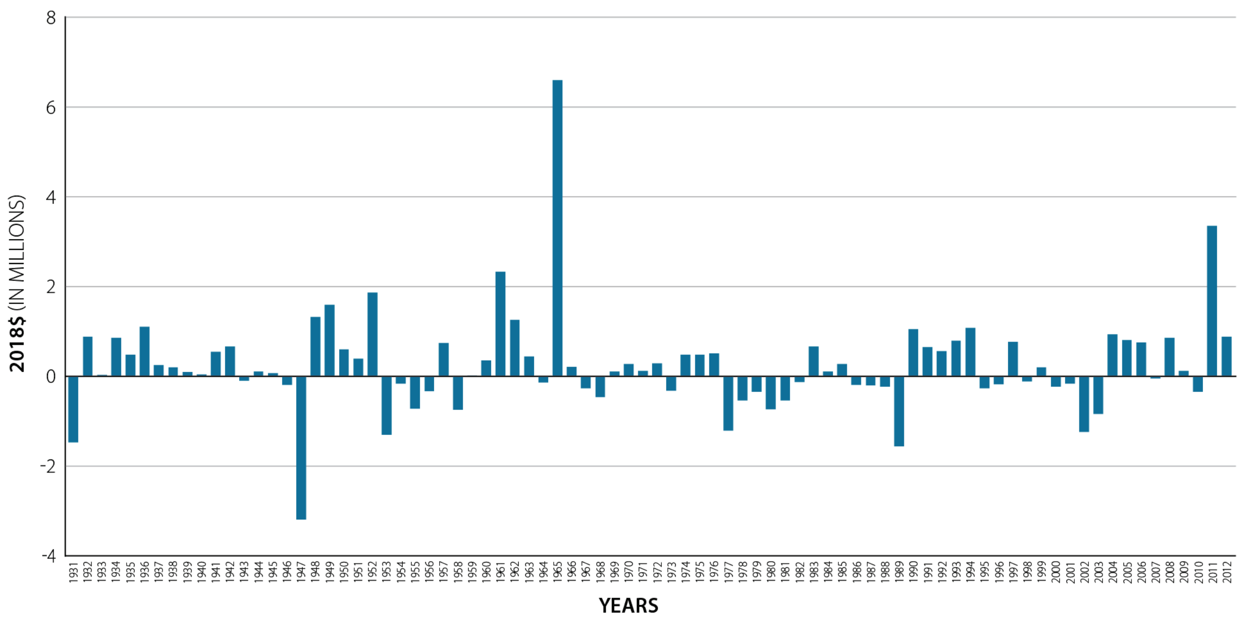

Figure 5. Annual Difference in Value of Alternative 3 Relative to Alternative 1 for Hydropower System Value

3.5 Alternative 4 – Spring ESH Creating Release

Alternative 4 focuses on developing ESH habitat through both mechanical and reservoir releases that would occur during the spring months.

The NED analysis for Alternative 4 is summarized by plant in Table 8. The average annual generation under this alternative is 8,660,832 MWh, a decrease of 60,246 MWh, when compared with Alternative 1 (the No Action alternative). This equates to an average annual decrease in generation value of $1,799,000.

The average annual summer dependable capacity is 2,106.9, a decrease of 8.9 MW compared to Alternative 1. The average annual winter dependable capacity is 1,847.1, a decrease of 12.8 MW. The maximum average annual impact to dependable capacity is a loss of $1,972,000. This was estimated by looking at each individual plant and determining which season had the greatest impact on that individual plant under that alternative. Each plant's maximum impact was then summed to show the maximum average annual impact on capacity. This value is also used to determine the total NED value impact for each alternative.

The overall impact of Alternative 4 as compared to Alternative 1 is a reduction of $3,771,000 which includes reductions in generation and dependable capacity in critical periods, which represents a decrease of 0.77 percent of the overall system value calculated under Alternative 1. The majority of the decrease, 79 percent, is occurring at Garrison and Oahe Dams. Alternative 4 would result in the largest adverse impacts to NED values of the action alternatives relative to Alternative 1.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 6 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 4 as compared to Alternative 1. The differences are plotted and color coded based on the type of release occurring each year. The graphic shows that full release years typically show increases in overall value during full release years, except for in 1982. The decrease to generation in this year is marginal overall, but large decreases are occurring in the summer months, affecting the capacity in the critical period. The greatest overall reductions in NED values occur in the years following the full and partial releases when reservoirs are lower than under Alternative 1 with impacts to generation and capacity value. The largest reduction in NED value as simulated would occur in 2010, the year after a partial release. The largest gain occurs in a full release year, 2002.

In 21 of the 82 years in the POR, Alternative 4 results in a higher hydropower value than Alternative 1. The average increase in these years would be $4,895,476. In 61 of the years, Alternative 4 would result in a lower hydropower value than Alternative 1. The average decrease in these types of years would be $5,587,000. The entire POR differences between Alternative 4 and Alternative 1 range from a gain of $25,963,000 in 2002 to a loss of $24,909,000 in 2010.

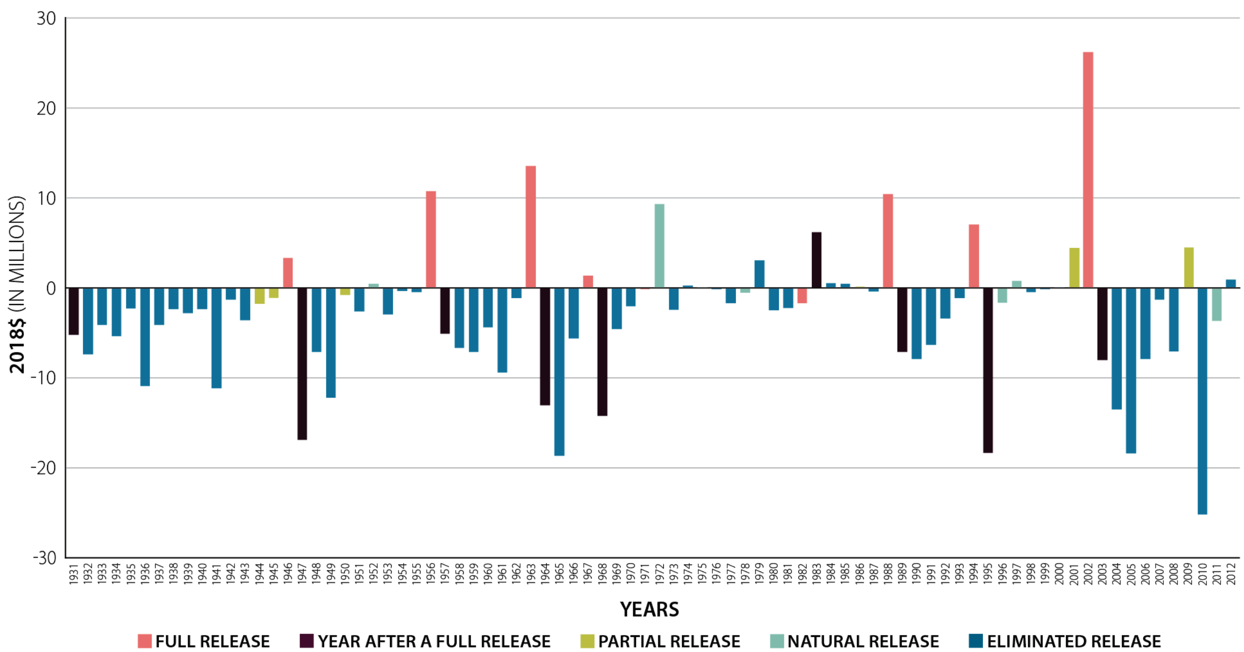

Figure 6. Annual Difference in Value of Alternative 4 Relative to Alternative 1 for Hydropower

Table 8. Summary of National Economic Development Analysis for Alternative 4 (FY18 Price Level)

NED Measure	Fort Peck	Garrison	Oahe	Big Bend	Fort Randall	Gavin's Point	Total
Average Annual Generation (MWh)	931,145	2,071,981	2,298,346	960,828	1,677,639	720,894	8,660,832
Generation Difference from Alternative 1 (MWh)	-556	-23,272	-21,788	-36	-8,567	-6,026	-60,246
Average Annual Generation Value	$22,923,000	$53,082,000	$62,216,000	$28,960,000	$42,807,000	$17,270,000	$227,258,000
Difference in Average Annual Generation Value from Alternative 1	-$9,000	-$714,000	-$715,000	-$13,000	-$207,000	-$141,000	-$1,799,000
Average Annual Dependable Capacity - Summer (MW)	179.4	435.6	575.2	460.4	340.8	115.5	2,106.9
Difference in Average Annual Dependable Capacity - Summer from Alternative 1 (MW)	1.0	-6.7	-4.0	0.7	0.1	0.0	-8.9
Average Annual Dependable Capacity Value - Summer	$22,212,000	$53,945,000	$71,240,000	$57,019,000	$42,209,000	$14,308,000	$260,933,000
Difference in Average Annual Dependable Capacity Value - Summer from Alternative 1	$126,000	-$834,000	-$493,000	$83,000	$8,000	$1,000	-$1,109,000
Average Annual Dependable Capacity - Winter (MW)	188.5	431.4	463.8	380.0	275.6	107.9	1,847.1
Difference in Average Annual Dependable Capacity - Winter from Alternative 1 (MW)	-1.3	-3.6	-5.8	-1.4	-0.4	-0.3	-12.8
Average Annual Dependable Capacity Value - Winter	$23,343,000	$53,424,000	$57,442,000	$47,057,000	$34,136,000	$13,358,000	$228,760,000
Difference in Average Annual Dependable Capacity Value - Winter from Alternative 1	-$165,000	-$448,000	-$718,000	-$176,000	-$47,000	-$33,000	-$1,587,000
Maximum Average Annual Capacity Loss	-$165,000	-$834,000	-$718,000	-$176,000	-$47,000	-$32,000	-$1,972,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	-$174,000	-$1,548,000	-$1,433,000	-$189,000	-$254,000	-$173,000	-$3,771,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	-0.39%	-1.43%	-1.06%	-0.22%	-0.30%	-0.55%	-0.77%

3.6 Alternative 5 – Fall ESH Creating Release

Alternative 5 would focus on developing ESH habitat through both mechanical and reservoir releases that would occur during the fall months. The NED analysis for Alternative 5 is summarized by plant in Table 9. The average annual generation under this alternative is 8,701,949 MWh, a decrease of 19,130 MWh, when compared with Alternative 1 (the No Action alternative). This equates to an average annual decrease in generation value of $678,000.

The average annual summer dependable capacity is 2,114.2, a decrease of 1.6 MW compared to Alternative 1. The average annual winter dependable capacity is 1,858.5, a decrease of 1.4 MW. The maximum average annual impact to dependable capacity is a loss of $353,000. This was determined by looking at each individual plant and determining which season had the greatest impact on that individual plant under that alternative. Each plant's maximum impact was then summed to show the maximum average annual impact on capacity. This value is also used to determine the total NED impact for a given alternative.

The overall NED impact of Alternative 5 as compared to Alternative 1 is a reduction of $1,031,000 which includes losses to generation and to dependable capacity in critical periods. This is a loss of 0.21 percent of the overall system value calculated under Alternative 1. The majority of the reduction, 65 percent, is occurring at Garrison and Oahe Dams. Alternative 5 has the second smallest impact of the alternatives analyzed.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 7 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 5 as compared to Alternative 1. The differences are plotted and color coded based on the type of release occurring each year. The figure indicates that full release years would result in an increase in overall value. However, in each case, the year immediately following the full release years would result in a reduction in NED values compared to Alternative 1. Overall, under Alternative 5 there are an equal number of years of increases and decreases compared to Alternative 1, but the decreases are relatively larger. The trend in Alternative 5 seems to be that while some large increases to hydropower system value occur during some full release years, most other types of water years are experiencing larger losses relative to the full release year gains. The largest decrease is occurring in the year after a full release, 1984.

In 41 of the 82 years in the POR, Alternative 5 results in a higher hydropower value than Alternative 1. The average increase in these types of years would be $3,197,000. In 41 of the years, Alternative 5 results in a lower hydropower value than Alternative 1. The average decrease in these years would be $4,931,220. The entire POR differences between Alternative 5 and Alternative 1 range from a gain of $18,223,000 in 1987 to a loss of $50,426,000 in 1984.

Table 9. Summary of National Economic Development Analysis for Alternative 5 (FY18 Price Level)

NED Measure	Fort Peck	Garrison	Oahe	Big Bend	Fort Randall	Gavin's Point	Total
Average Annual Generation (MWh)	932,892	2,091,473	2,314,804	960,562	1,676,926	725,293	8,701,949
Generation Difference from Alternative 1 (MWh)	1,191	-3,781	-5,329	-302	-9,281	-1,628	-19,130
Average Annual Generation Value	$22,954,000	$53,625,000	$62,713,000	$28,934,000	$42,782,000	$17,371,000	$228,379,000
Difference in Average Annual Generation Value from Alternative 1	$22,000	-$171,000	-$218,000	-$39,000	-$232,000	-$40,000	-$678,000
Average Annual Dependable Capacity - Summer (MW)	178.8	441.4	578.4	459.2	341.0	115.5	2114.2
Difference in Average Annual Dependable Capacity - Summer from Alternative 1 (MW)	0.4	-0.9	-0.8	-0.5	0.2	0.0	-1.6
Average Annual Dependable Capacity Value - Summer	$22,139,000	$54,670,000	$71,630,000	$56,872,000	$42,229,000	$14,308,000	$261,848,000
Difference in Average Annual Dependable Capacity Value - Summer from Alternative 1	$53,000	-$109,000	-$103,000	-$64,000	$28,000	$1,000	-$194,000
Average Annual Dependable Capacity - Winter (MW)	189.7	433.5	469.5	381.5	276.1	108.2	1858.5
Difference in Average Annual Dependable Capacity - Winter from Alternative 1 (MW)	-0.1	-1.5	-0.1	0.1	0.1	0.1	-1.4
Average Annual Dependable Capacity Value - Winter	$23,492,000	$53,693,000	$58,149,000	$47,246,000	$34,191,000	$13,403,000	$230,174,000
Difference in Average Annual Dependable Capacity Value - Winter from Alternative 1	-$16,000	-$179,000	-$11,000	$13,000	$8,000	$12,000	-$173,000
Maximum Average Annual Capacity Loss	-$16,000	-$180,000	-$103,000	-$64,000	$9,000	$1,000	-$353,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	$6,000	-$351,000	-$321,000	-$103,000	-$223,000	-$39,000	-$1,031,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	0.01%	-0.32%	-0.24%	-0.12%	-0.26%	-0.12%	-0.21%

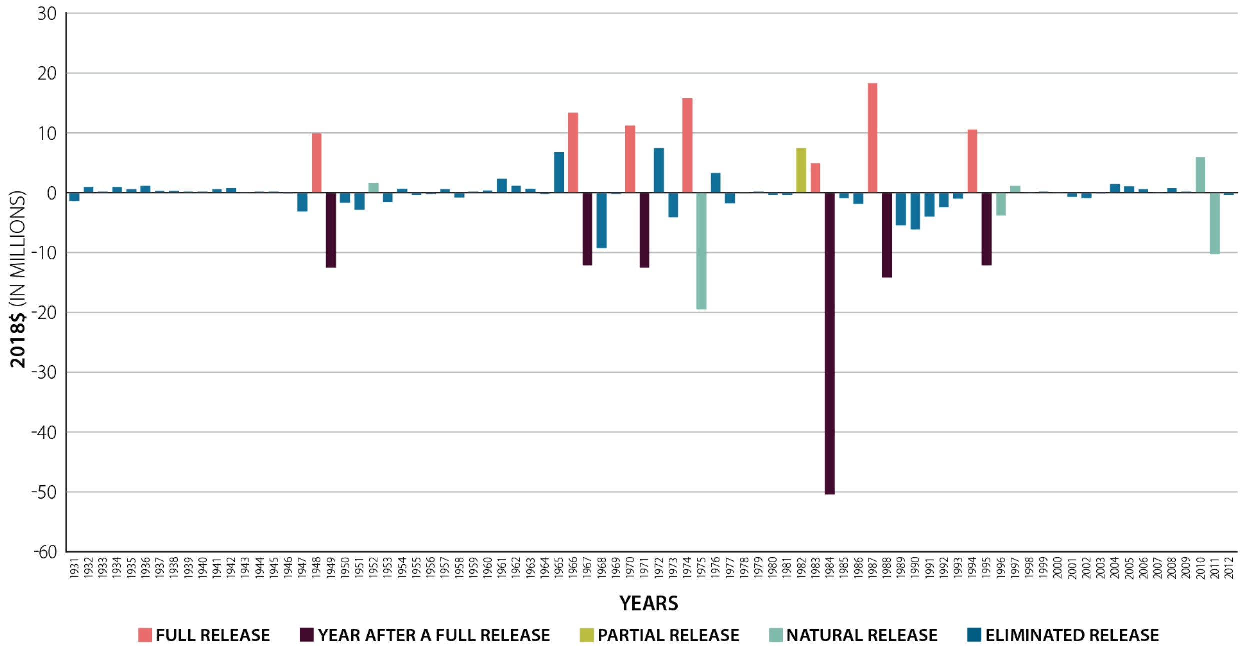

Figure 7. Annual Difference in Value of Alternative 5 Relative to Alternative 1 for Hydropower

3.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Alternative 6 includes actions that would develop ESH habitat through mechanical means and a spawning cue flow that would be mimicked through bi-modal pulses that would occur in March and May. The NED analysis for Alternative 6 is summarized by plant in Table 10. The average annual generation under this alternative is 8,679,355 MWh, a decrease of 41,724 MWh, when compared with Alternative 1 (the No Action alternative). This equates to a decrease in average annual generation value of $1.26 million.

The average annual summer dependable capacity is 2,103.2, a decrease of 12.6 MW compared to Alternative 1. The average annual winter dependable capacity is 1,848.4, a decrease of 11.5 MW. The maximum average annual impact to dependable capacity is a loss of $1,949,000. This was determined by looking at each individual plant and determining which season had the greatest impact on that individual plant under that alternative. Each plant's maximum impact was then summed to show the maximum average annual impact on capacity. This value is also used to determine the total impact assigned to a given alternative.

The overall impact of Alternative 6 as compared to Alternative 1 is a reduction of $3,209,000 which includes reductions to generation and to dependable capacity in critical periods. This is a reduction of 0.65 percent of the overall system value calculated under Alternative 1. Half of this reduction, 50 percent, is occurring at Oahe Dam. Garrison and Oahe Dams together are accounting for 85 percent of the loss. Alternative 6 has the second largest impact of the alternatives analyzed.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 8 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 6 as compared to Alternative 1. The differences are plotted and color coded based on the type of release occurring each year. There are gains to value in most full release years, but small losses in 1967 and 1970. Overall these years are showing increased generation, but large decreases in generation during the critical period months, resulting in losses. Years after a full release also are always showing reductions in NED value. However, the largest decreases are occurring in eliminated release years, 2004 and 2010.

In 25 of the 82 years in the POR, Alternative 6 results in a higher hydropower value than Alternative 1. The average increase in these types of years would be $2,915,280. In 57 of the years, Alternative 6 would results in a lower hydropower value than Alternative 1. The average decrease in these years would be $5,358,754. The entire POR differences between Alternative 6 and Alternative 1 range from a gain of $14,576,000 in 2002 to a loss of $18,838,000 in 2004.

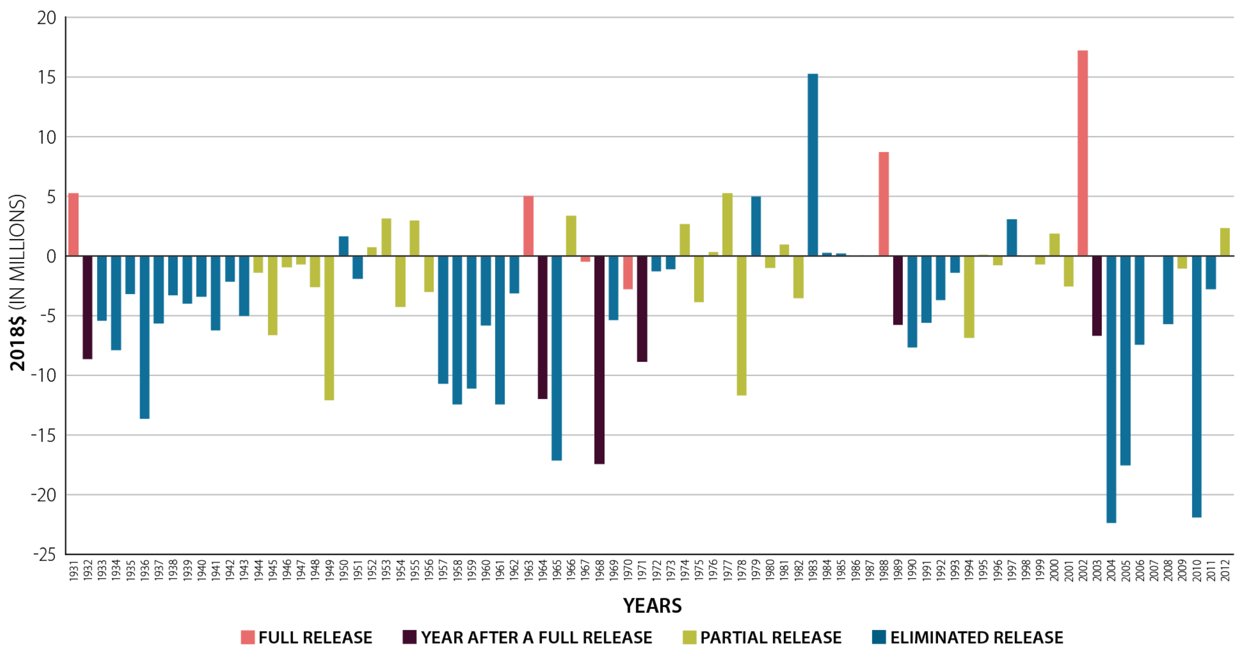

Figure 8. Annual Difference in Value of Alternative 6 Relative to Alternative 1 for Hydropower

Table 10. Summary of National Economic Development Analysis for Alternative 6 (FY18 Price Level)

NED Measure	Fort Peck	Garrison	Oahe	Big Bend	Fort Randall	Gavin's Point	Total
Average Annual Generation (MWh)	929,664	2,083,608	2,295,341	961,976	1,684,091	724,675	8,679,355
Generation Difference from Alternative 1 (MWh)	-2,036	-11,646	-24,793	1,112	-2,116	-2,246	-41,724
Average Annual Generation Value	$22,884,000	$53,423,000	$62,179,000	$28,996,000	$42,954,000	$17,361,000	$227,797,000
Difference in Average Annual Generation Value from Alternative 1	-$48,000	-$373,000	-$752,000	$23,000	-$60,000	-$50,000	-$1,260,000
Average Annual Dependable Capacity - Summer (MW)	178.2	436.3	572.3	460.1	340.8	115.6	2,103.2
Difference in Average Annual Dependable Capacity - Summer from Alternative 1 (MW)	-0.1	-6.0	-6.9	0.4	0.0	0.0	-12.6
Average Annual Dependable Capacity Value - Summer	$22,073,000	$54,032,000	$70,873,000	$56,987,000	$42,204,000	$14,311,000	$260,480,000
Difference in Average Annual Dependable Capacity Value - Summer from Alternative 1	-$13,000	-$747,000	-$860,000	$51,000	$3,000	$4,000	-$1,562,000
Average Annual Dependable Capacity - Winter (MW)	188.5	432.4	463.4	380.4	275.7	108.0	1,848.4
Difference in Average Annual Dependable Capacity - Winter from Alternative 1 (MW)	-1.4	-2.6	-6.2	-0.9	-0.3	-0.1	-11.5
Average Annual Dependable Capacity Value - Winter	$23,340,000	$53,555,000	$57,396,000	$47,117,000	$34,140,000	$13,373,000	$228,921,000
Difference in Average Annual Dependable Capacity Value - Winter from Alternative 1	-$168,000	-$317,000	-$764,000	-$116,000	-$43,000	-$18,000	-$1,426,000
Maximum Average Annual Capacity Loss	-$168,000	-$747,000	-$860,000	-$115,000	-$42,000	-$17,000	-$1,949,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	-$216,000	-$1,120,000	-$1,612,000	-$92,000	-$102,000	-$67,000	-$3,209,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	-0.48%	-1.03%	-1.20%	-0.11%	-0.12%	-0.21%	-0.65%

4.0 Regional Economic Development Evaluation Results

Regional Economic Development impacts are based on the results of the NED analysis. WAPA markets its firm power from hydropower to various preferred customers that meet federally mandated criteria. Changes to the operations of the system will impact WAPA's ability to meet the demand for electricity, possibly leading to the need to purchase power. The need to purchase power may lead to increases in electricity rates. If rates were to be impacted, there would be indirect RED effects such as impacts on disposable income for households or discretionary spending for businesses. These have the potential to affect jobs and income regionally.

Sales of electric power must repay all costs associated with power generation. WAPA provided the hourly preference customer and pumping load in the SPP footprint and the deliveries external to SPP, and they were compared to the generation data from the HBC model. Then net hourly generation for every day of the year was obtained by subtracting the load or demand from the generation. The prices used in these comparisons are different than those used for the NED analysis and were based on actual October 2015 through June 2016 average SPP LMP pricing at USACE generators in the SPP footprint for on/off peak periods.

4.1 Summary of Regional Economic Development Results

A summary of the RED impacts for each alternative are summarized in Table 11. Impacts are shown for the average of the 82-year POR.

Table 11. Environmental Consequences Relative to Hydropower: Regional Economic Development

Alternative	Financial Impact to WAPA on average
Alternative 2	($30,299)
Alternative 3	$102,358
Alternative 4	($1,155,522)
Alternative 5	($356,073)
Alternative 6	($792,147)

4.2 Alternative 1 – No Action

Under Alternative 1, the generation on an average annual basis would require an additional 195,594 MWh valued at $1,761,000 beyond the typical load requirements. In order to add some additional perspective to Alternative 1, the generation for 2008 were analyzed, which was a drought year. In 2008, under Alternative 1, generation for the system was shown to be a deficit of 3,273,900 MWh, meaning that WAPA power purchases would need to be made in order to meet the demand on the system.

4.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Under Alternative 2, on average, WAPA would incur a financial loss of $30,300. So, these values and numbers discussed represent the average annual difference between the net generation under Alternative 1 and Alternative 2. Then an on-peak and off-peak energy price was applied to indicate the financial impact to WAPA of each alternative.

Alternative 2 would increase power purchases or reduce surplus sales by about $30,300 on average. Of the 8,784 hours examined (all of the hours in a year), 57 percent of the hours resulted in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $514. The largest single hour purchase was $2,069 on average. About 43 percent of the hours provided surplus power and with that the ability to sell the power on the market at an average of $671.

4.4 Alternative 3– Mechanical Construction Only

Alternative 3 would decrease power purchases or increase surplus sales by a little over $100,000 in the average year. Of the 8,784 hours examined, 46 percent of the hours resulted in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $153. The largest single hour purchase on average was $1,205. Approximately 54 percent of the hours would provide surplus power and with that the ability to sell the power on the market at an average of $154.

4.5 Alternative 4 – Spring ESH Creating Release

Alternative 4 would increase power purchases or reduce surplus sales by more than $1.1 million on average. Of the 8,784 hours examined, 78 percent of the hours would result in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $402. The largest single hour purchase on average was $1,729. About 22 percent of the hours would provide surplus power and with that the ability to sell the power on the market at an average of $848.

4.6 Alternative 5 – Fall ESH Creating Release

Therefore, Alternative 5 would increase power purchases or reduce surplus sales by about $356,000 in on average. Of the 8,784 hours examined, 64 percent of the hours would result in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $290. The largest single hour purchase was $1,960. About 36 percent of the hours would provide surplus power and with that the ability to sell the power on the market at an average of $394.

4.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Therefore, Alternative 6 would increase power purchases or reduce surplus sales by about $792,000 on average. Of the 8,784 hours examined, 72 percent of the hours would result in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $320. The largest single hour purchase would average $1,604. About 28 percent of the hours would provide surplus power and with that the ability to sell the power on the market at an average of $512.

5.0 Other Social Effects Results

The OSE analysis for hydropower relied on the results of the NED analysis to show how changes to hydropower generation could impact air emissions. Reductions in hydropower generation would need to be made up by increasing other sources of power generation, likely to be a reliable fossil fuel source that produces greenhouse gases. As discussed in the methodology section, the EPA eGrid database was used to determine the appropriate region and emissions factors for this study. The emissions factors are 1,822 lbs/MWh for carbon dioxide, 0.154 lbs/MWh for methane, 0.029 lbs/MWh for nitrous oxide, and 2,204.62 lbs/MWh for carbon dioxide equivalent.

5.1 Summary of Other Social Effects Impacts

A summary of OSE impacts for the MRRMP-EIS alternatives is in Table 12. Table 13 summarizes the social cost of carbon.

Table 12. Environmental Consequences Relative to Hydropower: Other Social Effects

Change in Emissions	Carbon Dioxide (lbs)	Methane (lbs)	Nitrous Oxide (lbs)	Carbon Dioxide Equivalent (kt)
Average Annual Increase in Emissions under Alternative 2	9,855,094	833	157	4,500
Average Annual Decrease in Emissions under Alternative 3	10,999,306	930	175	5,022
Average Annual Increase in Emissions under Alternative 4	109,769,010	9,278	1,747	50,118
Average Annual Increase in Emissions under Alternative 5	34,854,585	2,946	555	15,914
Average Annual Increase in Emissions under Alternative 6	76,021,175	6,425	1,210	34,710

Table 13. Environmental Consequences Relative to Hydropower - Social Cost of Carbon

Change in Social Cost of Carbon	SCC 2018 Average	SCC - 2050 Average	SCC - 2050 95th Percentile
Change under Alternative 2	216,000.00	$369,000	$1,138,000
Change under Alternative 3	$241,000	412,000.00	$1,271,000
Change under Alternative 4	$2,406,000	$4,110,000	$12,680,000
Change under Alternative 5	$764,000	$1,305,000	$4,026,000
Change under Alternative 6	$1,666,000	$2,846,000	$8,782,000

SCC = social cost of carbon

5.2 Alternative 1 – No Action

Changes in hydropower operations have the potential to cause other types of effects than simply impacting generation and capacity values. An environmental benefit associated with hydropower is a reduction in greenhouse gases as compared to thermal power generation. If the Missouri River hydropower system generation was actually being produced by thermal power sources, it would increase annual emissions by 15,889,805,078 lbs of carbon dioxide, 1,343,046 lbs of methane, 252,911 lbs of nitrous oxide, which equates to the carbon dioxide equivalent of 15,994,458,021 lbs. The social cost of carbon discussed in the methodology section is intended to estimate the social costs of increased and decreased emissions.

The social cost of carbon for 2018 is $48 per metric tons of CO_2 (using a 3 percent discount rate). The social cost of the carbon emissions if the power currently generated by the hydropower system had to be generated by a thermal power source would be $348,239,000 based on the 2018 average social cost of carbon estimate. This could range up to a value of 1,835,508,000 using the 2050 95th percentile social cost of carbon estimate. The system does not produce these emissions, and therefore this benefit provides the baseline for the Other Social Effects accounts.

5.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Under Alternative 2, average annual emissions relative to Alternative 1 would likely increase, as the reductions in power generation would be made up by thermal power sources to meet the demand for power. Table 14 summarizes the OSE and emissions impact of replacing this average annual reduction in generation. A range of values for the Social Cost of Carbon was used to demonstrate different potential scenarios in different years. See section 3.3 for further description of these values.

Under Alternative 2, emissions would increase by 9,855,094 lbs of carbon dioxide, 833 lbs of methane, and 157 lbs of nitrous oxide annually. This would correspond to a 4,500 metric ton increase in carbon dioxide equivalent. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The average social cost of carbon for 2018 – 2050 would range from $216,000 to $369,000. Using the low probability, high-consequence estimates, the impacts would range from $621,000 to $1,138,000.

Table 14. Environmental Consequences Relative to Hydropower: Average Annual Change in Emissions

Alternative 2	
Average Annual Increase in Carbon Dioxide (lbs)	9,855,094
Average Annual Increase in Methane (lbs)	833
Average Annual Increase in Nitrous Oxide (lbs)	157
Average Annual Increase in Carbon Dioxide Equivalent (metric tons)	4,500
SCC - 2018 Average	$216,000
SCC - 2035 Average	$297,000
SCC - 2050 Average	$369,000
SCC - 2018 95 percentile	$621,000
SCC - 2035 95 percentile	$900,000
SCC -2050 95 percentile	$1,138,000

SCC = social cost of carbon

5.4 Alternative 3 – Mechanical Construction Only

Under Alternative 3, average annual emissions relative to Alternative 1 would decrease, as there is a small increase in average annual generation. Table 15 summarizes the OSE and emissions impact of this potential increase in hydropower generation. Under Alternative 3, emissions would decrease by 10,999,306 lbs of carbon dioxide, 930 lbs of methane, and 175 lbs of nitrous oxide annually. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The decrease in the average social cost of carbon for 2018–2050 would range from $241,000 to $412,000. Using the low probability, high-consequence estimates, the decrease in social cost of carbon would range from $693,000 to $1,271,000.

Table 15. Environmental Consequences Relative to Hydropower: Average Annual Change in Emissions

Alternative 3	
Average Annual Decrease in Carbon Dioxide (lbs)	10,999,306
Average Annual Decrease in Methane (lbs)	930
Average Annual Decrease in Nitrous Oxide (lbs)	175
Average Annual Decrease in Carbon Dioxide Equivalent (metric tons)	5,022
SCC - 2018 Average	-$241,000
SCC - 2035 Average	-$331,000
SCC - 2050 Average	-$412,000
SCC - 2018 95 percentile	-$693,000
SCC - 2035 95 percentile	-$1,004,000
SCC -2050 95 percentile	-$1,271,000

SCC = social cost of carbon

5.5 Alternative 4 – Spring ESH Creating Release

Under Alternative 4, average annual emissions relative to Alternative 1 would increase, as the reductions in power generation would likely be made up by thermal power sources. Table 16 summarizes the OSE and emissions impact of replacing this lost generation. Under Alternative 4, emissions would increase by 109,769,010 lbs of carbon dioxide, 9,278 lbs of methane, and 1,747 lbs of nitrous oxide annually. This would correspond to a 50,118 metric ton increase in carbon dioxide equivalent annual emissions. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The average social cost of carbon for 2018 – 2050 would range from $2,406,000 to $4,110,000. Using the low probability, high-consequence estimates, the social cost of carbon would range from $6,916,000 to $12,680,000.

Table 16 Environmental Consequences Relative to Hydropower: Average Annual Change in Emissions

Alternative 4	
Average Annual Increase in Carbon Dioxide (lbs)	109,769,010
Average Annual I Increase in Methane (lbs)	9,278
Average Annual Increase in Nitrous Oxide (lbs)	1,747
Average Annual Increase in Carbon Dioxide Equivalent (metric tons)	50,118
SCC - 2018 Average	$2,406,000
SCC - 2035 Average	$3,308,000
SCC - 2050 Average	$4,110,000
SCC - 2018 95 percentile	$6,916,000
SCC - 2035 95 percentile	$10,024,000
SCC -2050 95 percentile	$12,680,000

SCC = social cost of carbon

5.6 Alternative 5 – Fall ESH Creating Release

Under Alternative 5, average annual emissions relative to Alternative 1 would likely increase, as the reduction in power generation would likely be made up by thermal power sources. Table 17 shows the OSE and emissions impact of replacing this lost generation. Under Alternative 5, emissions would increase by 34,854,585 lbs of carbon dioxide, 2,946 lbs of methane, and 555 lbs of nitrous oxide annually. This would correspond to a 15,914 metric ton increase in carbon dioxide equivalent annual emissions. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The average social cost of carbon for 2018 – 2050 would range from $764,000 to $1,305,000. Using the low probability, high-consequence estimates, the social cost of carbon would range from $2,196,000 to $4,026,000.

Table 17. Environmental Consequences Relative to Hydropower: Average Annual Change in Emissions

Alternative 5	
Average Annual Increase in Carbon Dioxide (lbs)	34,854,585
Average Annual Increase in Methane (lbs)	2,946
Average Annual Increase in Nitrous Oxide (lbs)	555
Average Annual Increase in Carbon Dioxide Equivalent (metric tons)	15,914
SCC - 2018 Average	$764,000
SCC - 2035 Average	$1,050,000
SCC - 2050 Average	$1,305,000
SCC - 2018 95 percentile	$2,196,000
SCC - 2035 95 percentile	$3,183,000
SCC -2050 95 percentile	$4,026,000

SCC = social cost of carbon

5.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Under Alternative 6, average annual emissions relative to Alternative 1 would increase, as the reduction in power generation would likely be made up by thermal power sources. Table 18 shows the OSE and emissions impact of replacing this lost generation. Under Alternative 6, emissions would increase by 76,021,175 lbs of carbon dioxide, 6,425 lbs of methane, and 1,210 lbs of nitrous oxide annually. This would correspond to a 34,710 metric ton increase in carbon dioxide equivalent annual emissions. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The average social cost of carbon for 2018 – 2050 would range from $1,666,000 to $2,846,000. Using the low probability, high-consequence estimates, the impacts would range from $4,790,000 to $8,782,000.

Table 18. Environmental Consequences Relative to Hydropower: Average Annual Change in Emissions

Alternative 6	
Average Annual Increase in Carbon Dioxide (lbs)	76,021,175
Average Annual Increase in Methane (lbs)	6,425
Average Annual Increase in Nitrous Oxide (lbs)	1,210
Average Annual Increase in Carbon Dioxide Equivalent (metric tons)	34,710
SCC - 2018 Average	$1,666,000
SCC - 2035 Average	$2,291,000
SCC - 2050 Average	$2,846,000
SCC - 2018 95 percentile	$4,790,000
SCC - 2035 95 percentile	$6,942,000
SCC -2050 95 percentile	$8,782,000

SCC = social cost of carbon

6.0 Coupled Effects from Changes in Power Generation from Thermal Power and Hydropower Plants

If both hydropower and thermal power generation are affected during peak periods, there is a potential for coupled effects from reductions in both hydropower and thermal power plants. Simultaneous reductions in power generation, especially during peak seasons in the summer and winter, can exacerbate (i.e., increase) the adverse impacts to wholesale power prices and potentially electricity rates, electricity reliability, and regional economic conditions. Power generation estimates for both hydropower and thermal power were compared for each peak season (for every year) over the 36-year period (1975–2012 not including 2011) to evaluate the potential for coupled effects. Table 19 summarizes seasonal power generation in both the SPP and MISO Regional Transmission Organizations (RTOs) for each season. This data was averaged over two years of daily generation data from MISO and SPP (SPP 2015, 2016; MISO 2014, 2016).

Table 19. Average Power Generation by Season by RTO (MWh)

RTO	Winter	Spring	Summer	Fall
SPP	39,413,563	72,741,917	46,449,282	76,502,318
MISO	96,712,399	174,673,962	100,952,513	180,806,500
Total	136,125,962	247,415,879	147,401,794	257,308,818

Source: SPP 2015, 2016; MISO 2014, 2016

The following sections provide seasonal information on the potential impacts on power supply and generation from the coupled effects of hydropower and thermal power.

6.1 Summary Across Alternatives

All alternatives show some years when both hydropower and thermal power generation would be reduced relative to Alternative 1 (the No Action alternative). Under Alternative 2, coupled effects could potentially occur during summer months when low summer flow events would occur, causing the greatest potential for adverse impacts. Although Alternatives 3 through 6 would result in coupled effects during some years with both hydropower and thermal power generation reduced compared to Alternative 1 (the No Action alternative), the power generation affected as a percent of MISO and SPP generation is very small and the reductions typically occur in non-peak power demand season. In these conditions, there would be replacement capacity within SPP and MISO, and therefore, there would be minimal adverse impacts to wholesale power prices, electricity rates, grid stability, and regional economic conditions.

6.2 Alternative 1 – No Action

Under Alternative 1, seasonal power generation by year from both hydropower and thermal power plants along the Missouri River account for between 12 and 14 percent of seasonal power generation in the MISO and SPP RTOs (Table 20). During drought conditions, power generation under Alternative 1 would be a relatively lower percentage, especially in the summer season, from reduced power generation from both hydropower and thermal power plants. Compared to a high of 14.9 percent of MISO and SPP summer power generation (summer of 1975), drought conditions can cause the contribution of power generation from hydropower and thermal power to drop to 11.7 percent of the RTO generation (summer of 1980), a drop of 3.2 percent. In 1975, power generation from hydropower would be 3.2 million MWh and thermal power (18.7 million MWh), and in 1980, power generation from hydropower and thermal power plants would reduce to 2.2 million MWh and 14.9 million MWh, respectively.

Table 20. Combined Hydropower and Thermal Power Generation as a Percent of MISO and SPP Total Generation under Alternative 1

Year	Winter	Spring	Summer	Fall
1975	13.6%	14.1%	14.9%	14.6%
1976	13.7%	14.6%	14.3%	14.2%
1977	13.5%	13.7%	13.5%	13.7%
1978	13.3%	13.7%	14.5%	14.6%
1979	13.8%	14.3%	14.4%	14.0%

Year	Winter	Spring	Summer	Fall
1980	13.6%	13.8%	11.7%	14.1%
1981	13.5%	13.8%	13.8%	13.9%
1982	13.4%	13.5%	14.0%	14.3%
1983	13.7%	13.5%	12.1%	14.2%
1984	13.7%	13.6%	13.9%	14.1%
1985	13.7%	13.8%	13.8%	13.7%
1986	13.4%	13.4%	14.1%	14.2%
1987	14.0%	13.6%	12.3%	13.9%
1988	13.5%	13.5%	11.8%	13.8%
1989	13.4%	13.7%	13.6%	13.5%
1990	13.4%	13.5%	13.5%	13.2%
1991	13.2%	13.4%	12.8%	13.6%
1992	13.4%	13.6%	13.7%	12.5%
1993	13.3%	13.0%	13.1%	12.2%
1994	13.3%	13.7%	14.0%	13.6%
1995	13.3%	13.4%	13.9%	14.2%
1996	13.8%	14.6%	14.8%	14.2%
1997	13.6%	14.6%	14.8%	14.8%
1998	13.7%	13.7%	14.2%	14.0%
1999	13.6%	14.4%	14.0%	14.0%
2000	13.6%	14.0%	13.6%	13.8%
2001	13.4%	13.0%	12.9%	13.1%
2002	13.3%	13.6%	12.6%	13.5%
2003	13.3%	13.6%	12.0%	13.5%
2004	13.3%	13.5%	13.8%	12.5%
2005	13.2%	13.3%	12.4%	13.0%
2006	13.3%	13.3%	12.0%	13.1%
2007	13.3%	13.2%	13.0%	12.8%
2008	13.3%	13.2%	13.6%	13.4%
2009	13.3%	13.3%	13.7%	13.6%
2010	13.3%	12.8%	13.9%	14.1%
2012	13.6%	13.9%	12.0%	14.0%

6.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Under Alternative 2, coupled effects could potentially occur during summer months when low summer flow events would occur, which were simulated to occur over the years of the period of record (1975–2012) in 1988, 1989, 2002, and 2003. During the low summer flow events, both hydropower and thermal power would experience reductions in summer power generation during a season when demand for electricity is also typically high. These decreases in power generation in the summer would come during relatively drier conditions when power generation is already being affected, especially as simulated in 1988, 2002, and 2003. Reductions in power generation compared to Alternative 1 (the No Action alternative), as simulated, would be greatest in 1988 with a change of 5.9 million MWh, the bulk of which (88 percent) would be from reductions in thermal power generation. In the summer of 1988, the change in power generation under Alternative 2 as a percent of SPP and MISO summer power generation is estimated to be 4.0 percent. Table 21 summarizes the change in power generation from Alternative 1 (the No Action alternative) by season and by year as a percent of SPP and MISO power generation.

Table 21. Seasonal Change in Power Generation under Alternative 2 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation

Year	Winter	Spring	Summer	Fall
1975	-0.05%	-0.03%	-0.02%	-0.05%
1976	-0.05%	-0.02%	-0.16%	0.05%
1977	0.15%	0.06%	-0.05%	0.00%
1978	0.00%	0.02%	-0.02%	-0.03%
1979	-0.03%	0.09%	-0.22%	0.02%
1980	0.06%	0.11%	-0.01%	0.03%
1981	0.07%	0.02%	-0.10%	-0.05%
1982	-0.02%	0.06%	-0.01%	-0.01%
1983	-0.08%	0.54%	-0.07%	-0.22%
1984	-0.10%	0.09%	-0.25%	-0.16%
1985	-0.08%	-0.04%	-0.03%	-0.01%
1986	0.00%	0.38%	0.07%	-0.13%
1987	-0.30%	0.24%	-0.01%	-0.07%
1988	-0.10%	-0.05%	-4.01%	0.00%
1989	0.03%	0.03%	-1.42%	0.23%
1990	0.07%	0.07%	0.00%	0.09%
1991	0.02%	0.00%	-0.05%	0.00%
1992	0.00%	-0.01%	-0.05%	0.04%
1993	0.01%	0.01%	0.00%	0.00%
1994	0.00%	0.10%	-0.03%	0.01%
1995	0.00%	0.00%	-0.01%	0.09%
1996	-0.17%	-0.01%	-0.02%	0.03%
1997	-0.19%	0.03%	-0.03%	-0.19%
1998	0.08%	0.22%	-0.18%	-0.01%
1999	-0.08%	-0.03%	-0.08%	0.02%
2000	-0.02%	-0.12%	-0.07%	-0.01%
2001	-0.02%	0.03%	-0.08%	0.45%
2002	0.03%	0.05%	-1.49%	0.18%

Year	Winter	Spring	Summer	Fall
2003	0.02%	-0.02%	-0.66%	0.25%
2004	0.07%	-0.02%	-0.03%	-0.02%
2005	0.00%	-0.01%	-0.27%	-0.11%
2006	-0.01%	-0.05%	-0.07%	0.05%
2007	0.00%	0.00%	-0.24%	-0.14%
2008	0.01%	0.00%	-0.01%	-0.01%
2009	0.00%	0.02%	-0.02%	0.02%
2010	0.00%	0.22%	0.02%	0.05%
2012	-0.08%	0.02%	-0.12%	0.07%

These coupled effects in the summer season during the low summer flow events would exacerbate impacts to wholesale power prices, with relatively higher wholesale power prices with both sources of electricity unable to replace the power generation. Although replacement capacity within the markets is likely to be available during these conditions, it is possible that simultaneous reductions in power generation especially during a condensed period of time could adversely impact voltage pressure, local grid stability, available transmission capacity, and the availability of local electricity (SPP pers. comm. 2018).

The re-occurrence of these low summer flow events under Alternative 2 could lead to higher retail electricity rates. An increase in retail electricity rates may cause households to have less disposable income to spend on other goods and services in the community or region, causing adverse effects on local and regional economies. Similarly, businesses may have lower net revenue and less money to spend on other business expenses in the region.

6.4 Alternative 3 – Mechanical Construction

Under Alternative 3, there would be negligible coupled effects to both hydropower and thermal power generation. The fall of the modeled year 2005 shows the greatest impact of a power generation reduction of 259,022 MWh, 0.10 percent of both MISO and SPP generation, the bulk of which would be from reductions in thermal power generation (Table 22).

Table 22. Seasonal Change in Power Generation under Alternative 3 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation

Year	Winter	Spring	Summer	Fall
1975	0.00%	0.00%	0.01%	0.00%
1976	0.00%	0.01%	0.00%	0.00%
1977	0.00%	-0.03%	0.02%	0.00%
1978	0.00%	-0.01%	0.00%	0.01%
1979	0.00%	0.00%	0.00%	0.00%
1980	0.00%	-0.02%	0.02%	0.00%
1981	0.00%	-0.01%	0.02%	0.00%
1982	0.00%	-0.02%	0.03%	0.02%
1983	0.02%	-0.01%	0.00%	0.00%

Year	Winter	Spring	Summer	Fall
1984	0.00%	0.00%	0.01%	0.00%
1985	0.00%	0.00%	0.02%	0.00%
1986	0.00%	0.00%	0.01%	0.00%
1987	0.00%	-0.01%	0.02%	0.00%
1988	0.02%	-0.02%	0.07%	0.00%
1989	0.00%	-0.02%	0.00%	0.00%
1990	0.00%	0.00%	0.02%	0.03%
1991	0.01%	0.00%	0.02%	0.00%
1992	0.00%	0.00%	0.00%	0.01%
1993	0.01%	0.00%	0.01%	0.00%
1994	0.00%	0.02%	0.01%	0.00%
1995	0.00%	-0.01%	0.01%	0.00%
1996	-0.01%	0.00%	0.00%	0.00%
1997	0.00%	0.00%	0.02%	-0.01%
1998	0.00%	0.00%	-0.03%	0.00%
1999	0.00%	0.00%	-0.02%	0.00%
2000	0.00%	0.00%	-0.02%	0.00%
2001	0.00%	0.00%	0.04%	-0.01%
2002	0.00%	-0.02%	0.09%	0.00%
2003	0.00%	-0.01%	0.06%	0.00%
2004	0.00%	0.00%	0.01%	0.03%
2005	0.00%	0.00%	0.08%	-0.10%
2006	0.00%	0.00%	0.01%	0.01%
2007	0.00%	0.00%	0.00%	0.00%
2008	0.00%	0.00%	0.01%	0.01%
2009	0.00%	-0.01%	0.00%	0.00%
2010	0.00%	0.01%	-0.02%	0.01%
2012	0.03%	0.00%	0.04%	0.00%

6.5 Alternative 4 – Spring ESH Creating Release

Alternative 4 could result in adverse impacts to coupled generation from hydropower and thermal power, although these conditions would occur in the fall months (Table 23). The year 1994, when a full spring release is simulated to occur, would result in the largest power reduction of 2.6 million MWh compared to Alternative 1 (the No Action alternative), 2.4 million of which would be from thermal power plants. These reductions would be up to 1 percent of MISO and SPP generation in the fall in a modeled year like 1994. Because the reductions in power generation from hydropower and thermal power would occur in the fall and demand for electricity is generally relatively lower during the fall season, there would be replacement capacity, with minimal impacts to wholesale power prices, electricity rates, grid stability, and regional economic conditions.

Table 23. Seasonal Change in Power Generation under Alternative 4 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation

Year	Winter	Spring	Summer	Fall
1975	0.00%	0.00%	0.00%	0.00%
1976	0.00%	0.00%	0.00%	0.00%
1977	0.00%	-0.03%	0.02%	0.00%
1978	0.00%	-0.01%	0.01%	0.01%
1979	0.00%	0.11%	-0.05%	-0.03%
1980	-0.01%	-0.02%	0.01%	0.00%
1981	0.00%	-0.02%	0.00%	-0.01%
1982	-0.01%	0.38%	-0.13%	-0.30%
1983	-0.09%	-0.03%	0.02%	0.00%
1984	0.01%	0.00%	0.01%	0.00%
1985	0.00%	0.00%	0.02%	0.00%
1986	0.00%	0.06%	0.00%	-0.02%
1987	0.00%	-0.01%	0.02%	0.01%
1988	0.02%	0.33%	0.05%	-0.09%
1989	-0.03%	-0.03%	-0.02%	-0.01%
1990	-0.01%	-0.01%	0.00%	-0.16%
1991	-0.02%	-0.01%	0.01%	-0.13%
1992	-0.02%	0.00%	0.01%	-0.05%
1993	-0.02%	0.00%	0.00%	0.00%
1994	0.00%	0.31%	-0.08%	-1.02%
1995	-0.01%	-0.24%	0.01%	-0.10%
1996	-0.04%	0.00%	0.00%	0.00%
1997	0.00%	0.00%	0.02%	-0.01%
1998	0.00%	0.00%	-0.03%	0.01%
1999	0.00%	0.00%	-0.02%	0.00%
2000	0.00%	0.00%	-0.03%	0.00%
2001	0.00%	0.11%	0.01%	-0.02%
2002	0.00%	0.37%	0.12%	-0.01%
2003	-0.01%	-0.03%	0.04%	-0.06%
2004	-0.02%	-0.02%	-0.07%	0.28%
2005	0.02%	-0.02%	-0.02%	-0.06%
2006	0.01%	-0.01%	-0.02%	-0.05%
2007	0.00%	-0.01%	0.04%	-0.43%
2008	-0.01%	-0.02%	-0.01%	-0.17%

Year	Winter	Spring	Summer	Fall
2009	-0.03%	0.33%	-0.09%	-0.15%
2010	-0.05%	-0.32%	-0.26%	-0.13%
2012	0.01%	0.00%	0.05%	0.01%

6.6 Alternative 5 – Fall ESH Creating Release

Alternative 5 could result in adverse impacts to coupled generation from hydropower and thermal power, although these conditions would primarily occur in the spring months (Table 24). The year 1984, the year after a full fall release is simulated to occur, would result in the largest power reduction of 709,000 MWh compared to Alternative 1 (the No Action alternative), 654,000 MWh of which would be from hydropower plants. These reductions would be up to 0.3 percent of MISO and SPP generation in the spring as simulated. Because the reductions in power generation from hydropower and thermal power would occur in the spring and demand for electricity is generally relatively lower during the spring season, there would be replacement capacity, with minimal impacts to wholesale power prices, electricity rates, grid stability, and regional economic conditions.

Table 24. Seasonal Change in Power Generation under Alternative 5 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation

Year	Winter	Spring	Summer	Fall
1975	0.02%	-0.15%	-0.07%	-0.14%
1976	0.05%	-0.02%	0.03%	0.03%
1977	0.00%	-0.03%	0.01%	0.00%
1978	0.00%	-0.01%	0.00%	0.00%
1979	0.00%	0.00%	0.00%	0.00%
1980	0.00%	-0.01%	0.02%	0.00%
1981	0.00%	-0.01%	0.01%	0.00%
1982	0.00%	-0.03%	0.03%	0.15%
1983	-0.05%	-0.11%	0.02%	0.17%
1984	-0.03%	-0.29%	-0.18%	0.02%
1985	-0.01%	-0.01%	0.02%	0.00%
1986	0.00%	-0.01%	0.00%	-0.01%
1987	0.00%	0.00%	0.02%	0.33%
1988	0.00%	-0.12%	0.00%	-0.07%
1989	-0.02%	-0.03%	-0.02%	-0.01%
1990	-0.01%	-0.01%	0.00%	-0.13%
1991	-0.02%	0.00%	0.01%	-0.07%
1992	-0.01%	0.00%	0.00%	-0.03%
1993	-0.02%	0.00%	0.01%	0.00%
1994	0.00%	-0.13%	-0.04%	0.39%
1995	0.02%	-0.19%	-0.06%	-0.12%
1996	-0.09%	0.00%	-0.01%	0.00%

Year	Winter	Spring	Summer	Fall
1997	0.00%	0.00%	0.02%	-0.01%
1998	0.00%	0.00%	-0.03%	0.01%
1999	0.00%	0.00%	-0.02%	0.00%
2000	0.00%	0.00%	-0.02%	0.00%
2001	0.00%	0.00%	0.04%	-0.01%
2002	0.00%	-0.01%	0.08%	0.00%
2003	0.00%	-0.01%	0.06%	0.00%
2004	0.00%	0.00%	0.01%	0.02%
2005	0.00%	-0.01%	0.08%	-0.11%
2006	0.00%	0.00%	0.02%	0.01%
2007	0.00%	0.00%	0.00%	0.00%
2008	0.00%	0.00%	0.01%	0.01%
2009	0.00%	-0.01%	0.00%	0.00%
2010	0.00%	0.00%	-0.03%	0.11%
2012	-0.02%	0.00%	0.07%	0.00%

6.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Under Alternative 6, coupled effects of reductions in thermal power and hydropower generation would affect up to 0.4 percent of SPP and MISO generation (Table 25). The spring of the modeled year 2010 shows the greatest impact of a reduction of 0.4 percent of both MISO and SPP generation, the year after a partial release simulated to occur in 2009. Because the relatively small amount of power generation affected relative to capacity, there would be replacement capacity from other sources, with minimal impacts to wholesale power prices, electricity rates, grid stability, and regional economic conditions.

Table 25. Seasonal Change in Power Generation under Alternative 6 Compared to Alternative 1 as a Percent of Seasonal MISO and SPP Generation

Year	Winter	Spring	Summer	Fall
1975	-0.04%	0.04%	-0.02%	-0.04%
1976	0.00%	0.02%	-0.01%	0.01%
1977	0.01%	0.14%	0.03%	-0.03%
1978	-0.01%	-0.04%	-0.06%	-0.12%
1979	-0.01%	0.13%	-0.05%	-0.02%
1980	-0.01%	0.00%	0.01%	0.00%
1981	0.00%	0.11%	-0.01%	-0.05%
1982	-0.01%	0.06%	-0.01%	-0.08%
1983	-0.05%	-0.01%	0.05%	-0.01%
1984	-0.01%	0.00%	0.02%	0.00%
1985	0.00%	0.00%	0.02%	0.00%

Year	Winter	Spring	Summer	Fall
1986	0.00%	0.00%	0.01%	0.00%
1987	0.00%	-0.01%	0.02%	0.00%
1988	0.00%	0.20%	0.09%	-0.04%
1989	0.00%	-0.03%	-0.01%	-0.01%
1990	-0.01%	-0.01%	0.01%	-0.13%
1991	-0.02%	0.00%	0.01%	-0.09%
1992	-0.02%	0.00%	0.00%	-0.05%
1993	-0.02%	0.00%	0.00%	0.00%
1994	0.00%	-0.06%	-0.03%	0.01%
1995	0.00%	-0.01%	0.02%	-0.01%
1996	-0.01%	0.00%	-0.01%	0.00%
1997	0.00%	0.00%	0.01%	0.05%
1998	0.00%	0.01%	-0.02%	0.00%
1999	0.00%	0.00%	-0.02%	0.00%
2000	0.00%	0.08%	-0.05%	-0.03%
2001	0.03%	0.03%	-0.01%	-0.01%
2002	0.00%	0.19%	0.17%	0.01%
2003	0.00%	-0.03%	0.04%	-0.01%
2004	-0.01%	-0.02%	-0.08%	0.31%
2005	0.03%	-0.02%	-0.01%	-0.06%
2006	0.01%	-0.01%	-0.02%	-0.05%
2007	0.00%	-0.01%	0.03%	-0.27%
2008	-0.01%	-0.01%	0.00%	-0.14%
2009	-0.02%	0.06%	-0.04%	-0.02%
2010	0.00%	-0.41%	-0.35%	0.07%
2012	0.02%	0.02%	0.05%	0.01%

7.0 References

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