DRAFT

Missouri River Recovery Management Plan and Environmental Impact Statement

THERMAL POWER ENVIRONMENTAL CONSEQUENCES ANALYSIS TECHNICAL REPORT

December 2016

Intentionally Left Blank

Missouri River Recovery Management Plan and Environmental Impact Statement

Thermal Power Environmental Consequences Analysis

Technical Report

December 2016

Intentionally Left Blank

Table of Contents

List of Figures

List of Tables

Intentionally Left Blank

1.0 Introduction

The USACE in cooperation with the USFWS are developing a Missouri River Recovery Management Plan and Draft Environmental Impact Statement (MRRMP-Draft EIS). The purpose of the MRRMP Draft EIS is to develop a management plan that includes a suite of actions that removes or precludes jeopardy status for the piping plover, the interior least tern, and the pallid sturgeon using USACE authorities.

The purpose of the Thermal Power Environmental Consequences Analysis Technical Report is to provide supplemental information on the Thermal Power analysis in addition to the MRRMP-Draft EIS. Additional details on the National Economic Development (NED) and Regional Economic Development (RED) methodology and results are provided in this report. The OSE impacts are presented in the MRRMP-Draft EIS, Chapter 3, Thermal Power, Environmental Consequences section. No Environmental Quality (EQ) analysis was undertaken for thermal power.

1.1 Summary of Alternatives

The MRRMP-Draft EIS evaluates the following Management Plan alternatives. Detailed description of the alternatives is provided in the Draft EIS, Chapter 2.

- **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 BiOp compliance. Management actions under No Action include creation of early life stage habitat for the pallid sturgeon and emergent sandbar habitat (ESH), as well as a spring plenary pulse. The construction of habitat will be focused in the Garrison and Gavins reaches for ESH (an average rate of 107 acres per year) and between Ponca to the mouth near St. Louis for SWH (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 No Action 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 3,546 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 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 only create ESH through mechanical means at an average rate of 391 acres per year across the entire system. 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 additional 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.

- **Alternative 4 – Spring ESH Creating Release.** The USACE would mechanically construct ESH annually at an average rate of 240 acres per year across the entire system. 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 (current operations), with the addition of a spring release designed to create ESH for the least tern and piping plover. An additional 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 309 acres per year across the entire system. This alternative is based on Alternative 1 (current operations), with the addition of a release in the fall designed to create sandbar habitat for the least tern and piping plover. An additional 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 303 acres per year across the entire system. 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 or would be terminated whenever flood targets are exceeded. An additional 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-DraftEIS 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 MP-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 national economic development (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 regional economic development (RED) account registers changes in the distribution of regional economic activity (i.e. jobs and income).
- The environmental quality (EQ) displays non-monetary effect of significant natural and cultural resources.

- The other social effects (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. The Thermal Power Technical Report includes information on the NED and RED methodology and results.

1.3 Approach for Evaluating Environmental Consequences of Missouri River Recovery Management Plan

There are twenty-two thermal power plants are located along the Missouri River. One power plant is located on Lake Sakakwea and six are located between Garrison Dam and Lake Oahe (this river reach is referred to as both the Garrison reach and the Bismarck reach). The Garrison Reach is also called the “upper river” for the purposes of consistency with the figures in the NED evaluation. The remaining 15 plants are located in the lower river below Gavins Point Dam, near the following cities: Sioux City, Omaha, Nebraska City, Kansas City, and St. Louis.

Evaluation of the environmental consequences of the Management Plan to thermal power requires an understanding of how the physical conditions of the river would change under each of the Management Plan alternatives. Generally, thermal power plants are impacted by the Missouri River flows, stages and temperature conditions affecting intake access to water, the ability to discharge cooling water, and power plant operations and generation. Power plants need sufficient river stages to accommodate intake elevations. River temperatures can affect power plant operational efficiency and power generation. In addition, state water quality standards include a maximum river water temperature and maximum change in river water temperature within the mixing zone. Maximum temperatures requirements are 90 degrees Fahrenheit for plants along the lower sections of the Missouri River. When the river temperatures start to approach 90 degrees, power plants would need to curtail power generation to meet these temperature requirements.

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 impact thermal power operations and power generation. This figure also shows the intermediate factors and criteria that were applied in assessing the NED, RED, and OSE consequences to thermal power.

The environmental consequences analysis first focused on an analysis of the river stage, river flow, or temperatures at specified locations near power plants along the river relative to important intake and temperature thresholds under each of the MRRMP-Draft EIS alternatives. The results of this analysis provided important inputs for the NED, RED, and OSE evaluation, the second step in the process. The NED, RED, and OSE evaluation estimated impacts associated with changes in power plant operations and power generation under the MRRMP-Draft EIS alternatives. Figure 2 illustrates an overview of the approach for the thermal power evaluation.

CHANGES IN: Physical Components of Missouri River Watershed (including frequency, seasonality, and duration)

- River flows and stages
- Reservoir water surface elevations
- River water temperature
- Channel morphology

Leads To

CHANGES IN: Thermal Power Conditions

- Access to water
- Ability to discharge cooling water
- Thermal plant operational efficiencies

Leads To

CHANGES IN: Thermal Power Operations

- Reductions in power generation
- Replacement power generation
- Replacement of lost capacity
- Intake operations and maintenance activities

Leads To

CHANGES IN: Beneficial and/or Adverse National Economic Development (NED) Effects

- Capital investments to replace lost capacity, power replacement costs, variable costs

Leads To

CHANGES IN: Beneficial and/or Adverse Regional Economic Development (RED) Effects

- Changes in retail electricity rates
- Changes in regional economic conditions (from changes in electricity rates on household spending)

Leads To

CHANGES IN: Beneficial and/or Adverse Other Social Effects (OSE)

- Electricity reliability
- Air emissions
- Impacts on low income households

Figure 1. Flow Chart of Inputs Considered in Thermal Power Evaluation

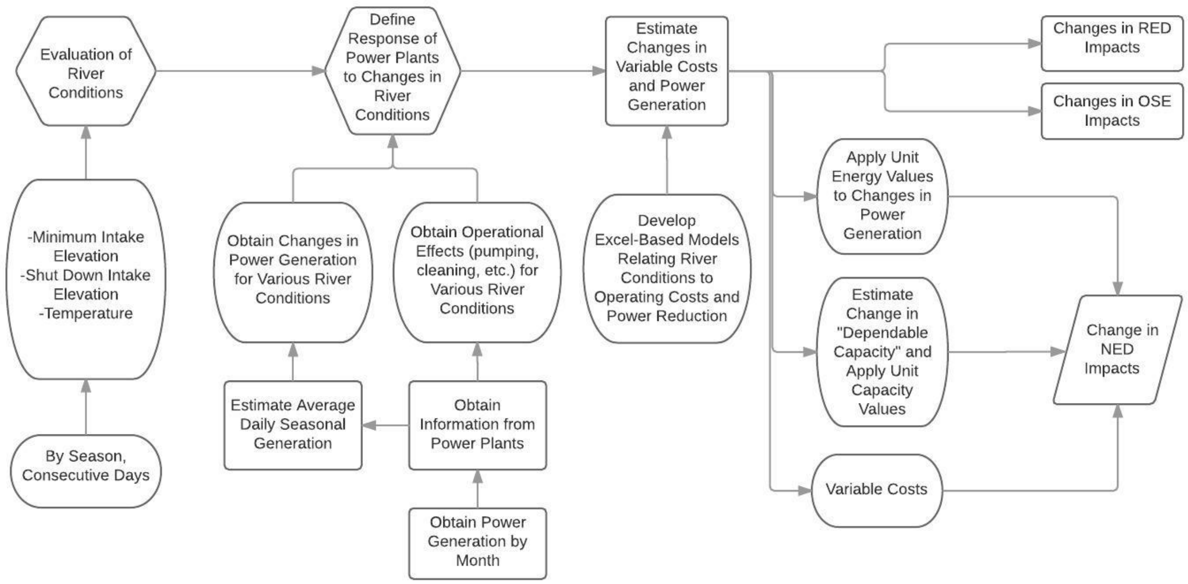

Figure 2. Environmental Consequences Approach for Thermal Power

The analysis of changes in river stages (relative to intake elevations) and river flows uses USACE Hydrologic Engineering Center River Analysis System (HEC-RAS) data for the period of record between 1931 and 2012 to assess when and how often intake access to water is affected. In addition, the Engineering Research and Development Center (ERDC) developed a HEC-RAS Water Quality temperature model to estimate daily temperatures for a 15-year period between 1995 and 2012 (excluding 2007, 2010, and 2011).[1] Please see the Hydrology and Hydraulics Water Quality Temperature Technical Report (available on the MRRP website at www.moriverrecovery.org) for additional details on the river temperature modeling. River temperatures are used to assess impacts to power generation from reduced operational efficiency and regulatory requirements. Because it was necessary to consider both water access and temperature impacts simultaneously to estimate accurate energy value and capacity value impacts to thermal power plants, the NED evaluation is based on the 15-year period. The period of analysis will be expanded as more river water temperature data is available in the spring of 2017 to include river water temperatures from 1975 to 2012. New river temperature data will be incorporated into the analysis for the final MRRMP-EIS. The following sections in this report provide further details on the methodology.

The one-time spawning cue test (Level 2) release that may be implemented under Alternatives 3, 4, and 5 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

[1] Years 2007, 2010, and 2011 in the HEC-RAS water quality temperature model were excluded from the analysis for the Draft EIS due to model limitations. Updates to the model will be incorporated into the analysis as available.

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.

2.0 Methodology and Assumptions

The methodology includes an evaluation of the relationship between river conditions and thermal power plants and uses this information to assess the NED, RED, and OSE impacts; these steps in the process are described in these sections.

2.1 Assumptions and Limitations

In modeling the environmental consequences to thermal power plants from the MRRMP-EIS alternatives, the project team established a set of assumptions. The following discussion highlights these assumptions to give the reviewer a better understanding of the objectives for the modeling effort. In addition, this section discusses the limitations of this modeling effort.

The key assumptions used in the modeling effort are as follows.

- The analysis uses data from the 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-period of record under each of the Management Plan alternatives as well as Alternative 1 (No Action).
- The analysis uses data from a water quality/river temperature model developed by USACE ERDC. The analysis assumes that the ERDC temperature models reasonably estimate river temperatures over the 15-year period of analysis under each of the Management Plan alternatives as well as Alternative 1 (No Action). Please see the Water Quality Temperature Technical Report.
- The project team conducted considerable outreach to power plants to understand how various river stages, flows, and temperature conditions adversely impact power plants (i.e., reduced power generation, increased costs). The project team has utilized information from interviews with power plants to assess how adverse effects would affect power generation and variable costs. Some of these conditions have not occurred in the recent past and therefore represent the anticipated operational response of a power plant to a hypothetical situation. It is assumed that the information provided by power plant officials adequately describes the impacts included in the modeling effort.
- Based on input from power plant representatives, it was assumed that all plants in the lower river would shut down when the river temperature was above 90 degrees Fahrenheit because discharging cooling water would violate the maximum temperature water quality standards.
- Unit capacity values, estimated by FERC and provided by the Hydropower Analysis Center, are used to represent the capital cost or major investment needed to replace lost capacity. The unit values are assumed to represent the cost to replace the capacity with an alternative source – combined cycle natural gas.
- The analysis depicts relatively large adverse impacts to power generation expected during dry years under current system operations. Some of these impacts would occur when river stages fall below critical intake thresholds. Recent bed degradation is likely causing water surface elevations to fall below critical thresholds in some locations. Since these conditions exist under current system management, which are modeled with a

2012 channel geometry, power plants would need to improve intakes to address these issues. The analysis presented here does not attempt to evaluate intake modifications resulting from bed degradation issues, but instead focuses on change in power generation and capacity relative to No Action as a result of the action alternatives.

2.2 Risk and Uncertainty

Risk and uncertainty are inherent with any model that is developed and used for water resource planning. Much of the risk and uncertainty with the overall Management Plan is associated with the operation of the Missouri River system and the extent to which flows and reservoir levels will mimic conditions that have occurred over the 82-year period of record. Unforeseen events such as climate change and weather patterns may cause river and reservoir conditions to change in the future and would not be captured by the HEC-RAS models or carried through to the thermal power model described is this document. The project team has attempted to address risk and uncertainty in the Management Plan by defining and evaluating a reasonable range of plan alternatives that include an array of management actions within an adaptive management framework for the Missouri River. All of the alternatives were modeled to estimate impacts to thermal power plants.

A source of uncertainty associated with the thermal power analysis is predicting how thermal power plants would react to long-term changes in river and reservoir conditions. The project team has utilized information from interviews with power plants to assess how adverse effects would affect power generation and variable costs. Some of these river conditions have not occurred in the recent past and therefore represent the anticipated operational response of a power plant to a hypothetical situation. However, while these operational responses may be reasonable under current conditions or in the near future, unforeseen conditions may arise that may alter the operational response to the adverse conditions.

In addition, investments to replace lost capacity during peak power demand seasons in this modeling effort may not reflect specific plant requirements and constraints. For consistency across all power plants, a standard approach to replacing changes in dependable capacity (used in hydropower evaluations) was used.

2.3 Evaluation of the Relationship between River Conditions and Thermal Power

The purpose of this analysis is to link the HEC-RAS modeling efforts, which simulate river operations of the Missouri River under each of the Management Plan alternatives, with the economic analysis necessary to estimate the consequences to thermal power plants. Specialized software was used to simulate river and reservoir operations for planning studies and decision support developed by the Institute for Water Resources, Hydrologic Engineering Center (HEC). Hydrologic Engineering Center River Analysis System (HEC-RAS) and ERDC's HEC-NSM temperature model data were used to provide a profile of river conditions at locations that approximately corresponded to locations of thermal power intakes. The analysis used Microsoft Excel® to evaluate potential effects of changes in river flows, river stages, and river temperatures on thermal power operations and power generation.

2.3.1 Thermal Power Intake Elevation and Flow Analysis

The following section describes the approach and structure of the analysis used to measure impacts to thermal power plant operations from changes in Missouri River flows and stages.

The intake elevation and flow analysis was used to evaluate when changes in river stages and flow levels would adversely affect thermal power plant intakes. Generally, power plants have specified two intake elevations: minimum intake elevation and shut down intake elevation. Minimum intake elevations are the water surface levels below which there would be small adverse impacts to power plant operations, such as additional pumping requirements as well as higher operations and maintenance costs for cleaning debris and sediment, compared to river stages at the shutdown intake elevation. When river stages fall below shut down intake elevations, more severe impacts occur to plants and most plants must shut down. HEC-RAS data was used to provide a profile of river behavior at locations that approximately corresponded to locations of thermal power plants intakes. River behavior for each location was modeled over a period of 82 years, from 1930 to 2012.

The USACE developed the initial list of thermal power plants along the Missouri River as well as one conversion station that could be potentially affected by changes in Missouri River flows and stages. Further research and discussions with thermal power plants eliminated one plant from analysis and several units at various plants as these plants or units are already decommissioned or planned for decommissioning in the next year. As a result, 21 thermal power plants located along the Missouri River were included in the analysis.

All of the power plant representatives and utilities provided input on the specific river stages and river flows that would adversely impact access to water for cooling. Eleven utilities representing 18 plants along with one electricity conversion station[2] provided feedback in follow-up discussions associated with operational changes and changes in power generation.

Information on minimum and shut down intake elevations was initially obtained from USACE and then verified or changed during interviews with utility or power plant operators. All intake elevation thresholds in the analysis are shown in feet above mean sea level (FAMSL) in the NAVD88 vertical datum. Many of the intake elevations were converted from NAVD29 to NAD88 to be consistent with the H&H models.

Inclusion of critical flows in the analysis was based on feedback from utilities and power plant operators. Specifically, a number of power plants indicated a critical low flow, while others indicated that the other metrics (intake elevations and temperature) were sufficient to evaluate potential adverse impacts to power plants. Power plant representatives provided critical low-flow thresholds. In most cases, these low-flow thresholds were an indication of severe adverse impacts to power plants, when power generation must be reduced. Several plant operators indicated that the average summer flow (July and August) is an important indicator that must be considered along with temperature conditions to determine the adverse impacts to plant operation and power generation. The summer flow threshold was used along with intake elevations only for the power plants that indicated that this condition was an important consideration.

Table 1 identifies the specific measures that were calculated for the thermal power intake elevation and flow analysis. As previously described, only those measures identified by the

---

[2] An electricity conversion station operated by Minnesota Power is affected when river stages at the Minnkota Power Missouri River Intake are below the shut down intake elevation.

plants/utilities as important to consider were included in the NED analysis for the specific power plant.

Table 1. Thermal Power Intake Elevation and Flow Analysis Conditions

River Conditions	Measure	Description
Condition 1 – Number of days river stages fall between the minimum intake elevation and the shut down intake elevation	Number of days by season	This measure is an estimate of the number of days in a season that a thermal power plant intake would experience minor adverse operating conditions (i.e., impacts to pumping, sediment clogging of intake, etc.). The focus of the metric is on operating conditions (and not shut down conditions).
Condition 2 – Number of days river stages fall below the shut down intake elevation	Number of days by season	This measure is an estimate of the number of days in a season that river stages fall below the shutdown intake elevation and the plant will have to shut down due to low water elevations. The focus of the metric is on shut down conditions.
Condition 3 – Number of days river flows will fall below plant operating flow requirements	Number of days by season	This measure is an estimate of the number of days in a season that river flows fall below an important operating threshold when plants will incur severe operational impacts and will reduce power generation. The focus of the metric is on shut down conditions.

This analysis specifically evaluated the number of days river flow and stage are below intake thresholds on a seasonal basis each year. Seasons are important to consider when power reductions occur because replacement costs for electricity (i.e., energy values) vary based on peak periods when demand for energy is greatest in the winter and summer months. In addition, plants also tend to produce more energy during peak periods when demand for electricity is highest, often operating close to full capacity. Refer to Section 0 for additional information on energy replacement values (energy values) and the seasons identified for the analysis.

2.3.2 Thermal Power Temperature Analysis

The following section describes the approach and structure of the analysis used to measure impacts to thermal power plant operations from changes in Missouri River water temperature. The temperature analysis was used to evaluate how thermal power plant operations would be affected by changes in river temperature. River temperatures can affect the cooling efficiency of plants, with potential impacts to power generation. In addition, state water quality standards for thermal power discharges specify a maximum river water temperature and maximum change in river water temperature within the mixing zone. Maximum temperature requirements are 90 degrees Fahrenheit for the 15 power plants located below Gavins Point Dam. When the river temperatures start to approach 90 degrees Fahrenheit, power plants in the lower river usually need to curtail power generation to meet the National Pollutant Discharge Elimination System (NPDES) temperature requirements. River temperatures also affect three of the power plants in the Garrison reach. The remaining four plants in the Garrison reach have cooling towers or systems and are not affected by river temperatures.

The analysis uses outputs from H&H models and the ERDC's HEC-NSM temperature model. ERDC provided daily temperature data for the years 1995 through 2012, excluding 2007, 2010 and 2011. [3] Again, the period of analysis for the temperature model will be extended and incorporated into the analysis when it becomes available.

The project team collected information from power plant operators and utilities to specify the temperatures and frequency of temperature conditions that would result in adverse conditions to power plants. These conditions were used with the ERDC daily temperature data to estimate the number of days during a season that the plant would experience these temperature conditions. For the plants in the lower river, the temperature analysis was based on various temperature groups – for example, a number of plants are assessed at each degree Fahrenheit between 85 and 90 degrees and a sixth group was specified for days that the temperature was above 90 degrees Fahrenheit. Each power plant operator or utility provided input into the temperature conditions and resulting power generation impacts for their plant(s). Some plants start to derate or reduce power generation at lower temperatures than others depending on their design standards. In addition, based on input from plant representatives, power plants in the lower river would be shut down above 90 degrees Fahrenheit because discharging cooling water at this river temperature would be in violation of their state water quality standards and their operating permits. Temperature conditions could affect plants in the Garrison reach, and various temperature conditions based on input from power plant representatives were specified for these plants to assess their operational impacts. Table 2 identifies the measures calculated in the temperature analysis.

Table 2. Temperature Analysis Metrics

River Conditions	Measure	Description
Condition 1 – Number of days river temperatures fall above or within critical threshold temperatures	Number of days per season	This measure is an estimate of the number of days in a season that the Missouri River is within critical temperature thresholds. The thresholds were determined based on input from power plants.

2.4 National Economic Development

An economic analysis was developed that builds upon the evaluation of river conditions analysis to evaluate the change in NED associated with thermal power operations and power generation as a result of the MRRMP-Draft EIS alternatives. NED impacts are defined as the costs, including power replacement costs and costs to replace lost capacity, incurred under various conditions that may occur as a result of adverse river conditions along the Missouri River.

Relationships were determined based on interviews with power plant operators and utilities. Energy and capacity values (obtained from the hydropower analysis) were applied to the estimates of lost power generation and capacity. Unit energy values represent the cost or price to replace reductions in power generation with electricity generation from the regional transmission organizations (RTOs). Capacity values are applied to a changes in dependable capacity relative to Alternative 1, which is based on decreases in power generation during peak power demand seasons. The changes in variable costs and energy and capacity values were aggregated for all power plants to estimate the NED impacts for each alternative. This section

[3] Years 2007, 2010, and 2011 were excluded from the analysis for the Draft EIS due to model limitations. Updates to the model will be incorporated into the analysis as available.

describes each of the steps included in the NED thermal power analysis and data sources used in the analysis.

2.4.1 Estimate Average Daily Seasonal Generation

One of the first steps in the NED analysis process was to obtain the power generation for potentially affected plants. Monthly generation was obtained from the U.S. Energy Information Administration (EIA) for the net generation for each power plant. Net generation is the amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries (EIA 2016). Power plants are obligated to report their monthly net generation through a form titled EIA 923. Because power plants are periodically taken off-line for repairs and maintenance, power plants and utilities were asked during interviews to provide a year that represented “typical” generation between 2012 and 2014 with no adverse impacts to power generation. Alternatively, an average of the three years was also provided as an option to use in the analysis. If plants were unresponsive to the information request, an average of the three years of power generation was used in the analysis.

Reductions in power generation were evaluated seasonally because replacement costs of power vary by season, with peak demand for electricity driving power replacement prices higher in the winter and summer months. In addition, power generation is also affected by demand for electricity, generally with higher generation during the peak summer and winter seasons. The determination of the seasons for the analysis included an assessment of the monthly energy prices (i.e., energy values), estimated through locational marginal pricing (described in Section 3.1.4). The months were grouped into seasons that reflected similar monthly prices. The seasons for the analysis were: spring (March through June), summer (July and August), fall (September through December), and winter (January and February).

The next step in the process was to estimate the average seasonal daily net generation. The monthly net generation for the appropriate units was aggregated for the months in each season. To estimate the average daily generation for each season, the total seasonal generation for each plant was divided by the number of days in each season to estimate the daily seasonal generation for each affected plant or unit.

2.4.2 Obtain Information from Power Plants on Adverse Conditions

Fourteen utilities were contacted for information regarding how river conditions affect power generation and variable costs (variable costs are described further Section 2.4.6). There are 22 thermal power plants located along or very close to the Missouri River. In addition, there is an electricity conversion station that can be affected when one thermal power plant is shut down. All power plant operators or utilities provided input on the shut down and minimum intake elevations for their associated power plants. Eleven utilities representing 18 power plants and one electricity conversion station provided information on conditions that would affect power generation for the economic evaluation.

After the utilities or power plant operators were contacted, telephone meetings were scheduled to describe the MRRMP-EIS alternatives and share the results of the intake elevation analyses associated with each power plant. As noted above, the initial analysis results included the number of days below the minimum and the shutdown intake elevation as well as the number of days above specific temperatures. These discussions provided the context for the discussion of the MRRMP-EIS impacts and provided the team with an opportunity to obtain more detailed information from the power plant representatives on their operational constraints. Given daily and seasonal information on the river flows, river stages, and temperature conditions for the Management Plan alternatives, the plants were asked to specify and/or verify the intake elevations, river flows or temperature conditions under which they would experience adverse conditions and to describe the adverse conditions. Multiple iterative discussions were held with the power plant representatives to elicit this information.

Based on these discussions, relationships between river stages, flows, and temperatures and adverse operating conditions were developed. If plants did not provide input despite several efforts to contact them, data and assumptions were based on input from representative plants (in a similar location and types of plant) for the analysis. This section generally describes how the relationships were established between power generation and river stages and flows; power generation and temperature conditions; and river stages and variable costs.

Adverse Effects Associated with River Stage Thresholds

Critical intake elevation thresholds were confirmed with all of the power plants, including both the shut down intake elevation and the minimum intake elevation. Most power plants were assumed to fully shut down when river stages drop below the shut down intake elevations, which was consistent with input from power plant representatives. For most plants, it is assumed that all average daily net power generation for the season (estimated under Section 2.4.1) would be lost for every day that the plant is shut down. There are exceptions to this approach when plants have reserve supplies of water; two such plants were identified in the outreach to power plants (see Section 2.4.2.3 for additional details). Additionally, a number of the plants do not experience any days below the shut down intake elevations and therefore were not included in the shut down intake elevations estimation. This occurred to seven plants in the period of analysis.

Power plant operators were also asked to describe adverse impacts associated with power plant operations below minimum intake elevation, but above the shut down intake elevation. Only one utility indicated that power generation would be affected under these river stage conditions, which was included in the analysis. A number of plants indicated that variable costs would be affected under minimum intake elevations (see Section 0 for additional details).

Adverse Effects Associated with River Flows Thresholds

Due to a dynamic channel in the Bismarck reach and the river flow/river stage relationship built into the HEC-RAS model, one plant indicated that river flow levels would provide a better indicator for simulating potential effects to their plant. In addition, a plant in the lower river uses supplemental pumps to access the river water during the non-navigation season, typically in the late fall though the spring. They indicated that when river flows fall below a specific threshold, especially in the summer and fall, they do not have permits for supplemental pumps, access to water and impacts from rising temperatures would be an issue. Plants are not permitted to have supplemental pumps during the navigation season due to navigation during this period. Most of the low river flows occur in the late fall and winter when the navigation season is over. The plant was assumed to shut down between July and October when the river flows were below the specified threshold during this period. Supplemental pumps and sufficient river flows maintain access to water through the intake for the remainder of the year.

Additional Plant Input on Shut Down Conditions

Input was also obtained from two plants with reserve supplies of water. One plant has a reserve of water that would allow it to continue to operate for approximately two weeks with the Missouri River intake shut down. However, these reserves would take about 10 days to replenish once the intake was able to access the water. Because the number of days shut down is dependent on the consecutive nature of the days, an assessment was undertaken using HEC-RAS daily stage data for the alternatives to evaluate when the plant would be affected.

Similar to the aforementioned plant, another intake pumps water to a lake and a separator impoundment. The lake and separator impoundment provide approximately 25 days of supply of water. A similar evaluation was undertaken on the consecutive days below the shut down intake elevation, along with input from the utility on the evaporation and refill factors, to assess when the plant and the conversion station would be affected. A conversion facility is affected when the intake is shut down and cannot transmit production tax credits (wind energy) during the summer. However, as modeled, there would be no impacts to this intake in the summer months between 1995 and 2012.

Adverse Effects Associated with River Temperature Conditions

River temperatures have the potential to affect power generation through decreased operational plant efficiencies in cooling the condenser of the plant; as river water temperatures increase to a point at which the cooling efficiency is affected, the plant may have to decrease power generation, also known as derating the plant. Some plants prefer to address temperature issues through an assessment of river flows, which are highly correlated with river temperatures (discussed above under river flow conditions). In addition, state water quality standards in the lower river (Missouri, Kansas, Nebraska, Iowa) include maximum river water temperatures that are included in the NPDES permits for the plant. When the river temperature approaches the maximum river temperatures in the water quality standards, most plants need to reduce power generation to meet the NPDES temperature requirements.

The ERDC daily temperature model and results were discussed with the power plants. The power plant operators were asked to describe the adverse conditions and power generation reductions associated with specific river water temperatures or river flows.

The thermal power temperature analysis then associated the river temperatures or flows that adversely impacted plant operations and generation. According to all plants located in the lower river that provided input, above a river temperature of 90 degrees Fahrenheit (the state water quality standard for Missouri, Kansas, Nebraska, and Iowa), the plants would need to fully shut down due to water quality standards. These temperature conditions and maximum river temperatures only apply to plants in the river below Gavins Point Dam.

Many of the plants with once through cooling systems need to derate due to higher temperatures because of decreases in the cooling efficiency at the plant. The operational efficiency of power plants with recirculating cooling systems is not affected by higher river temperatures because the plant relies on the cooling tower or system and not the river water temperature to cool its condensers.

Five utilities representing nine power plants provided information on temperature impacts to power generation for the plants located below Gavins Point Dam. Based from input from plant representatives, it was assumed that all plants (including those plants that did not provide input) in the lower river were affected by river temperatures. Plants that did not provide input were assumed to incur impacts similar to neighboring plants.

Four plants in the Bismarck reach have recirculating cooling systems and are not anticipated to be impacted by river temperatures. Three utilities in the Bismarck reach provided temperature impacts for their plants and were incorporated into the NED model. In addition, it is possible that river temperature conditions near Bismarck, North Dakota as modeled in the mid-2000s would be higher than indicated in the ERDC temperature model due to changes in operational releases from Garrison Dam during drought conditions to support the cold water fishery in the reservoir. These specific operational considerations are not included in the ERDC temperature model or in the NED modeling, therefore, impacts associated with temperatures on these three plants could be greater than simulated.[4]

2.4.3 Estimate Power Generation Reductions

The evaluation of river conditions described under section 2.3 was used along with the average daily seasonal generation (with no adverse river conditions) in section 2.4.1 and the information obtained from power plants in 2.4.2 to estimate power generation reductions. An Excel®-based model was used to estimate these seasonal, yearly reductions in power generation over the 15-year period of analysis.

There were no instances when there were estimated impacts to power generation from both river stages and flows and from temperature. The potential for double counting of days was considered in situations where plants experienced reductions in power generation from river stages falling below shut down intake or flow thresholds and with impacts from higher water temperature conditions. A manual comparison of flow and stage results against temperature results was done to ensure that the model did not double count power generation reductions from these conditions. River temperature impacts usually occur in the summer (some in the spring) and river flows and stages are generally higher during these seasons. Lower river flows and stages typically occur in the fall and winter season when temperatures are not as high.

2.4.4 Estimate Energy Values

Energy values estimate the value of replacement energy if electricity generation is reduced under the MRRMP-EIS alternatives. Energy values are the product of the reduction in energy (i.e. power generation) in megawatt-hours and an energy unit value price ($/MWh). The approach to estimate the reduction in power generation was described in Sections 2.3, 2.4.1, 2.4.2 and 2.4.3

The unit energy value was based on the cost to purchase electricity in the market. Energy values for the Missouri River were estimated by the Hydropower Analysis Center using LMP from the Western Area Power Administration hub of both the Midwest Independent System Operator (MISO) Regional Transmission Organization (RTO) and the Southwest Power Pool

[4] Three power plant representatives in the Bismarck reach described issues related to temperature during the mid-2000s (2005-2009). Plywood was installed at Garrison Dam to release water from the top of the reservoir to support the cold water fishery in Lake Sakakawea, which adversely affected the plants. The temperature model does not incorporate the higher river temperatures due to the releases between 2005 and 2009. The temperatures could be higher in the mid-2000s than modeled here.

(SPP). LMP is a computational technique that determines a shadow price for an additional MWh of demand.

Power plants along the Missouri River are members of the MISO and SPP RTOs, generally with more northern utilities being members of MISO and southern utilities being members of SPP. The MISO and SPP energy values (LMP) were used for the member plants in the analysis.

Because unit energy values are an energy price and represent the full cost of the replacement energy, they are inclusive of any variable costs associated with reduced power generation. The energy values include “blocks” based on peak and non-peak times, and vary by month as well as weekends and weekdays. Because all of the thermal power plants are base load plants, the peaking and non-peaking times of the day were not used for the energy values. However, values can change daily and seasonally; therefore, average energy values for weekend and weekdays by month in 2012 were used. A seasonal energy value (spring, summer, fall, and winter) was estimated from the monthly and weekend/weekend energy values; months with similar energy values were combined to estimate the seasonal values. The seasonal energy values (2012 present value of forecasted values) were estimated by weighing the number of the weekend days and weekdays in the relevant season. The 2012 energy values were inflated to 2016 dollars with GDP deflators (OMB 2016). The peak seasons of summer (July and August) and winter (January and February) reflect higher values than other months of the year. The seasons were defined as follows:

- Winter: January and February
- Spring: March through June
- Summer: July and August
- Fall: September through December

The energy values used in the analysis are shown in Table 3.

Table 3. MISO and SPP Unit Energy Values, 2016$

Season	MISO Weighted Seasonal Energy Values ($/MWH)	SPP Weighted Seasonal Energy Values ($/MWH)
Summer	$43.19	$30.68
Fall	$25.82	$26.28
Winter	$39.61	$37.80
Spring	$28.93	$33.76

Source: Hydropower Analysis Center, 2015

The unit energy values were applied to the estimates of reduced power generation under the various conditions for each plant, for each year and season, and for each alternative to estimate losses in energy values, which represent the replacement costs of reduced energy generation.

2.4.5 Estimate Capacity Values

Capacity values represent the cost to construct and operate a new power plant or a major investment to replace lost capacity. Capacity values are relevant when a new plant needs to be constructed or large capital investment needs to be made. Capacity values should be applied when an investment is needed to replace lost capacity with a new source. The potential need to replace capacity is estimated through an evaluation of the long-term effects of the alternative on the power plant and its power generation, especially during peak periods when all capacity is being used. The approach to estimate the capacity values through a dependable capacity approach is provided in the following subsections.

Estimate Dependable Capacity

The dependable capacity of a thermal power plant or unit is a measure of the amount of capacity that the unit or power plant can reliably contribute towards meeting system peak power demands. Dependable capacity can be computed in several ways. The method that is appropriate for evaluating the dependable capacity of a predominantly thermal-based power system like those in the Missouri River Basin is the specified availability method, which is described in Section 6 of EM 1110-2-1701, HYDROPOWER Engineering and Design (USACE 1985). The following steps were used to model dependable capacity.

Estimate the total seasonal capability for each power plant during the peak summer and winter seasons. The total seasonal capability is the amount of power generation in a typical year where there are no adverse impacts (also known as total seasonal generation). The total seasonal capability was estimated using EIA data for a typical year, as described Section 2.4.1.

Estimate the reductions in power generation for each plant for each peak winter and summer season for each year.

Subtract the reduction in power generation for each plant for the winter and summer season from the total seasonal capability (step 2 from step 3), which provides the estimated amount of generation that would occur in the relevant season in each year.

Estimate the number of hours within each season, which is the number of days in the season multiplied by 24 hours/day.

Model the capacity for each year, peak season, and plant. Divide the amount of power generated in the peak seasons (step 3) by the total number of hours in the season (step 4).

Estimate the dependable capacity. Based on discussions with the Hydropower Analysis Center and guidance in the Hydropower Engineer Manual 1110-2-1701, the 15th percentile (85th percent exceedance) of the annual peak season capacity estimates for each plant was used. This represents the amount of capacity that a plant can reliably contribute to meeting peak season needs (pers. comm. Hydropower Analysis Center 2015; USACE 1985).

Estimate Unit Capacity Values

Capacity values represent the cost to construct and operate a new power facility or major investment to replace lost capacity. Capacity values are reported as a dollar amount per KW or MW per year and include fixed plant costs and variable operating costs. The unit capacity value is applied to the dependable capacity to estimate the capacity values under each alternative for each plant and each peak season.

The unit capacity values are based on a FERC spreadsheet model that estimates annual regional capacity values for different generating resources (Hydropower Analysis Center, 2015).

The capacity values for the Midwest Reliability Council West electricity market module as defined by the EIA are:

- Coal $198.82 per KW-year
- Combined cycle $118.57 per KW-year
- Combustion turbine $56.58 per KW-year

Because a combined cycle gas-fired thermal plant would the most likely replace a coal or nuclear-fired plant (Hydropower Analysis Center, pers. comm. 2015), the capacity value used for this analysis is $118.57/KW-year. For consistency with the dependable capacity unit (MW), the capacity value was multiplied by 1,000 to provide a unit capacity value of $118,570 per MW-year in 2012 dollars. The unit capacity value was inflated to 2016 dollars with the OMB GDP inflator, resulting in a 2016 value of $136,657 per MW-year. Capacity values do not include decommissioning costs if a plant or a unit would need to be retired or decommissioned. Therefore, these capacity values (i.e., capital cost estimates) reflect conservative estimates of the possible capital costs to replace the capacity under the alternatives. In particular, nuclear plant decommissioning costs are substantial and could increase these impacts to power plants if decommissioning a unit or facility would need to occur.

Estimate Capacity Values

The unit capacity value of $136,657 was applied to the dependable capacity (15th percentile of the capacity in each year for each peak season). The capacity values are estimated compared to the no action condition. If there was no change in capacity relative to the no action alternative, the change in capacity value would be zero.

The final step in the process was to choose the larger of the two changes in capacity values (from the no action alternative) for summer and winter for each plant and each alternative, which represents the worst case requirement to replace capacity (Hydropower Analysis Center, pers. comm. 2015). The change in capacity value represents an annualized capital cost (or decrease in capital cost), and therefore the capacity value is applied to each year to estimate the capital cost impacts (fixed and variable costs) to replace lost capacity under the MRRMP-EIS alternatives.

2.4.6 Estimate Variable Costs

The power plant representatives were asked how the river stages, flows, and temperatures could affect their operations, other than power generation, and to specify the associated variable costs. Any costs incurred when power generation was also being reduced were assumed to be captured within the energy values analysis because energy values reflect the full replacement cost of the power to be purchased in the market. Two plant operators (located in the Garrison reach) were able to specify increased variable costs incurred during periods between minimum and shut down intake elevations when the plants were not reducing their power generation. A separate plant provided an intake cleaning cost when river stages are between shut down and minimum intake elevations. Most of the power plant operators or utility representatives felt that the impacts to power generation captured the bulk of the impacts.

2.5 Regional Economic Development

The RED analysis used power generation information from the SPP and MISO Regional Transmission Organizations (RTOs) and consultation with RTO experts to describe the potential impacts of the reductions in power generation on wholesale electricity prices and how changes to those prices could impact consumer electricity rates that are set by retail electricity providers. Any changes in retail electricity rates could impact household and business spending, with implications for jobs and income in regional economies. If consumers must spend more of their income on higher electricity rates, they would have less disposable income to spend on other goods and services, which could adversely impact jobs and income in affected industries. The RED analysis considered the worst-case peak seasonal reduction in power generation as a percent of total seasonal generation for the RTOs, the timing of the reductions in power generation within the peak season, and input from SPP to qualitatively assess the potential impacts to electricity rates and RED effects. Additional information on USACE RED methodology is available within the IWR 2011 Report on Regional Economic Development Procedures Handbook (USACE 2011).

A reduction in power generation due to adverse river conditions would result in the use of alternative sources of power. Because the thermal power plants along the Missouri River are base load plants, they are generally lower-priced electricity generators compared to other fossil fuel plants. Therefore, if these power plants must reduce power generation because of adverse conditions, the next available power source could be at a marginally higher price than these base-load generators. If multiple power plants reduce power generation during peak summer seasons, the cost to retail electricity providers would temporarily increase because the next marginal energy producer would charge more per unit of energy produced. When there are reductions in power generation in peak periods during adverse conditions (i.e., high river temperatures), the price increases would likely be much higher than if power generation were reduced during off-peak times (i.e., fall and spring). In the situation where RTO capacity is limited during peak periods, some of the highest-cost resources would be made operational, increasing wholesale electricity prices. If the Missouri River thermal power plants must reduce power generation for a long period or on a re-occurring basis during peak periods, this could create an increase in the wholesale cost of electricity to retail electrical providers, although it would takes time for price changes in the wholesale market to be reflected in the consumer market.

Consumer electricity rates are typically regulated by the state utility commission, but can also be unregulated. If the rates are regulated, the retail electricity provider, with sufficient justification, petitions the state utility regulatory commission to change the rates. The commission then makes the decision on whether the retail electricity rates should be increased. In an unregulated market, the retail electricity provider can typically change the consumer electricity rate without permission from a state regulating authority.

Input was also obtained from experts to better understand the magnitude of power reductions during peak seasons which could affect wholesale electricity prices such that retail electricity providers would have justification to petition for electricity rate changes (SPP pers. comm. 2016; WAPA pers. comm. 2016). If multiple power plants must reduce power generation simultaneously during peak summer seasons or if Missouri River thermal power plants must reduce power generation for a long period or on a re-occurring basis during peak periods, this could create an average increase in the wholesale cost of electricity to retail electrical providers. The providers may then have sufficient rationale to petition state utility commissions for an increase in consumer electricity rates.

Power generation from the MISO 2013 Annual Market Assessment Report and the SPP 2014 State of the Market Report were obtained to better understand the level of generation and relative importance of the reductions in power generation in each of the RTO markets from Missouri River plants during peak seasons (MISO 2014; MISO 2016; SPP 2015; SPP 2016). The average power generation during these two years for each RTO is presented seasonally in the analysis (Tables 4 and 5). The analysis considers the impacts of the alternatives for the worst-case peak season reduction in power generation over the 15-year period and are also presented as a proportion of the MISO and SPP seasonal power generation. The RED evaluation used the RTO average season power generation along with RTO input, and the anticipated timing (i.e., number of plants affected simultaneously) to assess potential impacts to consumer electricity rates and regional economic conditions. Tables 4 and 5 summarize the total generation in megawatt hours (MWh) by month within each RTO.

Table 4. Annual Generation within SPP by Month (Monthly Average 2014-2015)

Month	Total SPP Gen (MWh)
1	20,674,110
2	18,739,453
3	18,332,751
4	16,364,566
5	17,476,396
6	20,568,204
7	23,198,268
8	23,251,014
9	19,782,663
10	18,162,332
11	18,502,615
12	20,054,707

Source: SPP 2015; SPP 2016

Table 5. Total Generation within MISO by Month (Monthly Average 2013-2014)

Month	Total MISO Generation (MWh)
1	51,691,786
2	45,020,612
3	45,675,629
4	40,455,915
5	42,552,243
6	45,990,174
7	49,928,354
8	51,024,159
9	43,827,539
10	42,308,793
11	44,092,782
12	50,577,387

Source: MISO 2014; MISO 2016

3.0 National Economic Development Results

This section provides the results of the NED analysis. A summary of results across all alternatives is presented first, followed by a detailed description of the results by alternative.

3.1 Summary of Alternatives

Adverse river conditions, such as reduced river flows or elevations or increased river temperature, can affect thermal power operations and power generation. The NED analysis for thermal power focused on estimating the changes in variable costs, energy and capacity values occurring as a result of changing physical conditions along the Missouri River under the MRRMP-EIS alternatives. The results of the H&H modeling show that river elevations, flows, and temperatures would impact thermal power plants evaluated under all the MRRMP-EIS alternatives including Alternative 1. The impacts to thermal power plants would include a change in costs to replace lost energy, capacity, and to address adverse operating conditions (variable costs).

Tables 6, 7, and 7 provide a summary of the NED analysis for each of the MRRMP-EIS alternatives. Table 6 summarizes the results for all of the thermal power plants under analysis. As currently modeled over the 15-year period of analysis, the effect of adverse conditions on average annual energy values, capacity values and variable costs would range from $52.6 million under Alternative 3 (the least adverse impact) to $81.1 million under Alternative 2 (the greatest adverse impacts) over the 15-year period. Alternatives 3, 5, and 6 would have beneficial impacts on average annual power generation, energy values, and total NED effects, while Alternatives 2 and 4 would result in adverse impacts compared to Alternative 1. The low summer flow events, which would occur as simulated in two of the 15-year period of analysis under Alternative 2, would result in adverse impacts to power generation, energy values, and capacity values for power plants in the lower river, with an average annual increase in NED costs or losses of 68.2 percent compared to Alternative 1. The average annual reductions in power generation from adverse conditions represent from 1.5 to 1.7 percent of total annual power generation for all Missouri River power plants without adverse conditions (93 million MWh). However, annual changes in power generation fluctuate depending on river conditions, and under Alternative 2 under the low summer flow event simulated in 2002 (worst impacted-year), 5.6 percent of power generation without adverse conditions would be affected.

Table 7 and Figure 3 summarizes the NED analysis for thermal power plants in the Garrison reach (i.e., the upper river). As currently modeled over the 15-year period of analysis, the effect of adverse conditions on energy values, capacity values and variable costs would range from $11.1 million under Alternative 2 (least adverse impacts) to $13.4 million (greatest adverse impact) under Alternative 4. Relative to Alternative 1, Alternative 4 would result in the greatest increase in NED losses (15.3%) or $1.8 million on average per year. Alternative 2, 3, 5, and 6 would result in a beneficial impacts to power generation, energy values, and total NED values compared to Alternative 1. Annual average reductions in power generation under all alternatives for power plants in the upper river would range from 1.8 to 2.2 percent of Missouri River power generation without adverse conditions (23.7 million MWh), with Alternative 4 accounting for the largest adverse impacts. In a release year as simulated in 2009, 1.5 million MWh or 4.4 percent of power generation without adverse impacts from these plants would be affected.

Table 6. Estimated Thermal Power National Economic Development Results for MRRMP-Draft EIS Alternatives for All Power Plants

All Locations	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6
Effect of Adverse Conditions on Power Generation (Annual Average MWH)	1,482,484	1,632,268	1,432,559	1,507,305	1,440,620	1,420,535
Percent of Change in Power Generation as a Percent of Missouri River Total Power Generation with No Adverse Impacts (93 million MWh)	1.6%	1.7%	1.5%	1.6%	1.5%	1.5%
Change in Power Generation from Alternative 1 (Annual Average MWH)	NA	149,783	-49,926	24,821	-41,864	-61,950
Effect of Adverse Conditions on Energy Values (Annual Average)[b]	$52,900,819	$58,980,999	$51,223,396	$53,006,010	$51,526,175	$50,549,508
Percent Change in Energy in Energy Values	NA	11.5%	-3.2%	0.2%	-2.6%	-4.4%
Effect of Adverse Conditions on Capacity Values (Annual Average)[d]	NA	$22,081,810	$314,065	$314,065	$314,065	$1,053,903
Summer Dependable Capacity (MW)[d]	8,308.1	8,150.1	8,392.7	8,432.6	8,392.7	8,500.8
Winter Dependable Capacity (MW)[d]	10,185.8	10,185.2	10,185.8	10,185.8	10,185.8	10,185.2
Variable Costs (Annual Average)[c]	$31,869	$32,948	$28,508	$34,523	$29,508	$28,050
Effect of Adverse Conditions on NED Values (Energy Values, Capacity Values and Variable Costs) (Annual Average)	**$52,932,688**	**$81,095,757**	**$51,565,968**	**$53,354,598**	**$51,869,577**	**$51,631,461**
Change in NED Impacts from Alternative 1 (Annual Average)	**NA**	**$28,163,069**	**-$1,366,719**	**$421,911**	**-$1,063,111**	**-$1,301,226**
Percentage Change from Alternative 1	NA	68.2%	-3.3%	1.0%	-2.6%	-3.2%

Note: Higher positive values represent higher costs (or higher reductions in power generation) associated with adverse river conditions, while negative values represent lower costs or higher values (increases in power generation) when compared to Alternative 1.

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach, while the lower river includes all power plants below Gavins Point Dam

b Energy values represent replacement costs for power generation that is reduced under adverse conditions.

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected.

d Dependable capacity is estimated as the 15th percentile of the annual peak season capacity for each plant. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $136,657/MW-year (Hydropower Analysis Center 2015).

Table 7. Estimated Thermal Power National Economic Development Results for MRRMP-Draft EIS Alternatives for Power Plants in the Upper River

Upper River	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6
Effect of Adverse Conditions on Power Generation (Annual Average MWH)	449,284	424,763	434,994	516,747	435,801	443,479
Percent of Change in Power Generation as a Percent of Missouri River Total Power Generation with No Adverse Impacts (23.7 million MWh)	1.9%	1.8%	1.8%	2.2%	1.8%	1.9%
Change in Power Generation (Annual Average MWH)	NA	-24,521	-14,290	67,462	-13,483	-5,805
Effect of Adverse Conditions on Energy Values (Annual Average)[b]	$11,621,394	$10,993,420	$11,255,167	$13,366,638	$11,273,712	$11,477,234
Percent Change in Energy in Energy Values	NA	-5.4%	-3.2%	15.0%	-3.0%	-1.2%
Effect of Adverse Conditions on Capacity Values (Annual Average)[d]	NA	$86,338	$38,884	$38,884	$38,884	$138,183
Summer Dependable Capacity (MW)[d]	2,917.7	2,917.8	2,917.5	2,917.5	2,917.5	2,917.4
Winter Dependable Capacity (MW)[d]	2,953.5	2,952.9	2,953.5	2,953.5	2,953.5	2,952.9
Variable Costs (Annual Average)[c]	$31,869	$32,948	$28,508	$34,523	$29,508	$28,050
Effect of Adverse Conditions on NED Values (Energy Values, Capacity Values and Variable Costs) (Annual Average)	**$11,653,263**	**$11,112,706**	**$11,322,558**	**$13,440,044**	**$11,341,932**	**$11,643,467**
Change in NED Impacts from Alternative 1 (Annual Average)	**NA**	**-$540,556**	**-$330,705**	**$1,786,782**	**-$311,331**	**-$9,795**
Percentage Change from Alternative 1	NA	-4.6%	-2.8%	15.3%	-2.7%	-0.1%

Note: Higher positive values represent higher costs (or higher reductions in power generation) associated with adverse river conditions, while negative values represent lower costs or higher values (increases in power generation) when compared to Alternative 1

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach, while the lower river includes all power plants below Gavins Point Dam

b Energy values represent replacement costs for power generation that is reduced under adverse conditions.

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected.

d Dependable capacity is estimated as the 15th percentile of the annual peak season capacity for each plant. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $136,657/MW-year (Hydropower Analysis Center 2015).

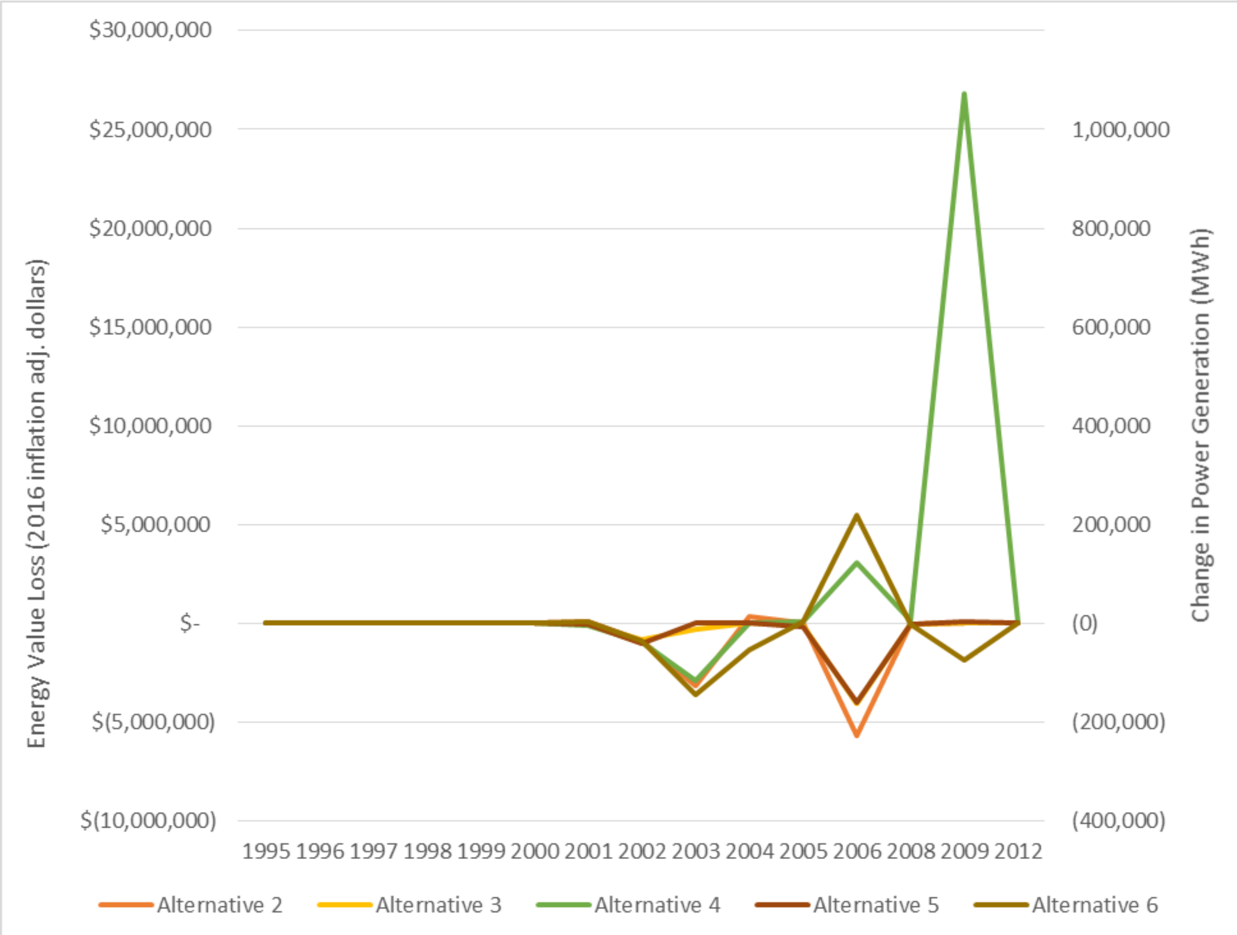

Figure 3. Change in Power Generation and Energy Values Relative to No Action for the Upper River Power Plants (higher positive values indicate more costs or losses)

The MRRMP-EIS alternatives have varying impacts on power plants in the lower river (Table 8 and Figure 4). Thermal power plants in the lower river would be mostly impacted by changes in the river temperature. NED effects would range from $39.9 million (least adverse impact) under Alternative 4 to $70.0 million under Alternative 2 (greatest adverse impact) on average over the 15-year period of analysis. Relative to Alternative 1, Alternative 2 would result in the greatest increase in NED losses (69.5%) or $28.7 million on average for thermal power plants in the lower river. Beneficial impacts to power generation, energy values, and NED effects would occur under Alternatives 3, 4, 5, and 6 relative to Alternative 1, with Alternative 3 having the largest reduction in NED costs or losses of 3.3 percent compared to Alternative 1. The average annual reductions in power generation from adverse conditions represent from 1.4 to 1.7 percent of total annual power generation for all Missouri River power plants without adverse conditions (69.7 million MWh). However, annual changes in power generation fluctuate depending on river conditions, and under Alternative 2 under the low summer flow event simulated in 2002 (worst impacted-year), 1.6 million MWh or 2.3 percent of power generation without adverse conditions would be affected.

Table 8. Estimated Thermal Power National Economic Development Results for MRRMP-EIS Alternatives for Power Plants in the Lower River

Lower River	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6
Effect of Adverse Conditions on Power Generation (Annual Average MWH)	1,033,200	1,207,505	997,564	990,558	1,004,819	997,056
Percent of Change in Power Generation as a Percent of Missouri River Total Power Generation with No Adverse Impacts (69.7 million MWh)	1.5%	1.7%	1.5%	1.4%	1.4%	1.6%
Change in Power Generation (Annual Average MWH)	NA	174,305	-35,636	-42,642	-28,381	-56,144
Effect of Adverse Conditions on Energy Values (Annual Average)[b]	$41,279,425	$47,987,579	$39,968,229	$39,639,373	$40,252,464	$39,072,274
Percent Change in Energy in Energy Values	NA	16.3%	-3.2%	-4.0%	-2.5%	-5.3%
Effect of Adverse Conditions on Capacity Values (Annual Average)[d]	NA	$21,995,472	$275,181	$275,181	$275,181	$915,719
Summer Dependable Capacity (MW)[d]	6,645.3	6,487.6	6,730.1	6,770.0	6,730.1	6,838.3
Winter Dependable Capacity (MW)[d]	8,570.3	8,570.3	8,570.3	8,570.3	8,570.3	8,570.3
Variable Costs (Annual Average)[c]	NA	NA	NA	NA	NA	NA
Effect of Adverse Conditions on NED Values (Energy Values, Capacity Values and Variable Costs) (Annual Average)	**$41,279,425**	**$69,983,050**	**$40,243,410**	**$39,914,554**	**$40,527,645**	**$39,987,994**
Change in NED Impacts from Alternative 1 (Annual Average)	**NA**	**$28,703,626**	**-$1,036,015**	**-$1,364,871**	**-$751,780**	**-$1,291,431**
Percentage Change from Alternative 1	NA	69.5%	-2.5%	-3.3%	-1.8%	-3.1%

Note: Higher positive values represent higher costs (or higher reductions in power generation) associated with adverse river conditions, while negative values represent lower costs or higher values (increases in power generation) when compared to Alternative 1

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach, while the lower river includes all power plants below Gavins Point Dam

b Energy values represent replacement costs for power generation that is reduced under adverse conditions.

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected.

d Dependable capacity is estimated as the 15th percentile of the annual peak season capacity for each plant. Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $136,657/MW-year (Hydropower Analysis Center 2015).

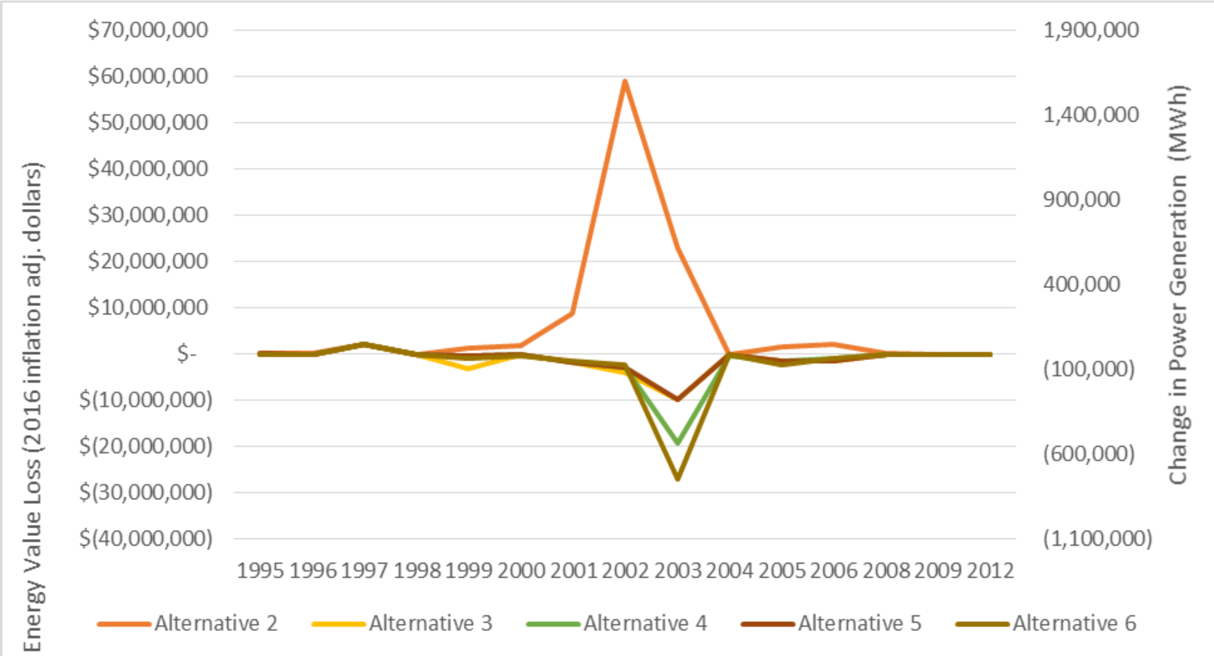

Figure 4. Change in Power Generation and Energy Values Relative to No Action for the Lower River Power Plants (higher positive values indicate more costs or losses)

3.2 Alternative 1 – No Action (Current System Operations and MRRP Management Actions)

Alternative 1 represents current system operations including a number of management actions associated with the MRRP and BiOp compliance. Management actions under Alternative 1 include creation of early life history habitat for the pallid sturgeon and ESH habitat, as well as a spring plenary pulse. The construction of habitat will be focused in the Garrison and Gavins reaches for ESH habitat creation and between Ponca to the mouth near St. Louis for SWH.

Management of the Missouri River system under Alternative 1 would result in an annual average decrease of $52.9 million[5] in energy values (i.e., $52.9 million in replacement costs of reduced power generation) over the 15-year period of analysis when compared to conditions when power generation would not be affected by adverse conditions. Most (78%) of this impact would be to power plants in the lower river. The vast majority of these adverse impacts would be due to high river temperature conditions in the summer months during the drought conditions simulated under Alternative 1 in the 2000s, which resulted in lower river flows in the summer and/or higher ambient air temperatures, causing river temperatures to increase above certain critical operating and regulatory thresholds for power plants. During these adverse conditions, twelve power plants in the lower river would be impacted during these relatively drier conditions. Because power generation would be affected in peak summer seasons, it is possible that electricity prices for replacement power would be higher than estimated with locational marginal pricing, resulting in larger adverse effects to energy values than reported here. These

[5] In this analysis, positive values represent costs for power plants, including costs to replace lost power generation, lost capacity, or variable costs.

reductions in power generation would account for 1.6 percent of total Missouri River power plant generation under conditions when no adverse impacts would occur.

Alternative 1 would result in an average annual reduction of $11.6 million in energy values in the upper river when compared to annual power generation from Missouri River plants with no adverse impacts to power generation. The reduction in power generation under Alternative 1 would account for 1.9 percent of power generation under no adverse conditions in the upper river. Most of the impacts in the upper river would occur with reduced river flows in relatively drier conditions in September through November affecting access to water through intakes.

Lost capacity occurs if power generation is impacted during peak summer and winter seasons. Capacity values for Alternatives 2-6 are based on the loss in dependable capacity relative to Alternative 1 and are defined as the amount of capacity that a power plant can reliably contribute to meeting peak season needs (USACE EM 1110-2-1701). Under Alternative 1, dependable capacity would be higher in the winter (11,524 MW) compared to the summer (9,563 MW) for all power plants in the lower river due to temperatures affecting power generation during the peak summer season. Capacity values, because they are calculated relative to Alternative 1, are not estimated for Alternative 1. Impacts to variable costs would be small under Alternative 1, with less than a half million over 15 years and an average annual cost of $31,869. The NED analysis for Alternative 1 is summarized in Table 9.

Table 9. Summary of NED Analysis for Alternative 1

Costs	Upper River[a]	Lower River	All Locations
Effect of Adverse Conditions on Energy Values (Total over 15 years)[b]	$174,320,910	$619,191,372	$793,512,282
Effect of Adverse Conditions on Energy Values (Average Annual)	$11,621,394	$41,279,425	$52,900,819
Maximum Loss in Annual Energy Values Costs	$74,052,467	$146,695,066	$147,882,573
Minimum Loss in Annual Energy Values Costs	$0	$908,836	$908,836
Average Annual Reduction in Missouri River Power Generation from Adverse Conditions under Alt 1 (MWh)	449,284	1,033,200	1,482,484
Percent of Power Generation relative to Generation with No Adverse Conditions (MWh) (93 million MWh total)	1.9%	1.5%	1.6%
Total Variable Costs[c]	$478,030	NA	$478,030
Average Annual Variable Costs	$31,869	NA	$31,869
Summer Dependable Capacity[d] (MW)	2,917.7	6,645.3	9,563.0
Winter Dependable Capacity[d] (MW)	2,953.5	8,570.3	11,523.8
Effect of Adverse Conditions on Energy Values and Variable Costs (Total)	$174,798,941	$619,181,372	$793,990,313
Effect of Adverse Conditions on Energy Values and Variable Costs (Annual Average)	$11,653,263	$41,279,425	$52,932,688

Note: Higher positive values represent higher costs associated with adverse river conditions.

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant on Lake Sakakawea.

b Energy values represent replacement costs for power generation that is reduced under adverse conditions.

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected.

d Dependable Capacity is estimated as the 15th percentile of the annual peak season capacity for each power plant, which represents the amount of capacity that a power plant can reliably contribute to meeting peak season needs (USACE EM 1110-2-1701).

3.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Alternative 2 includes a spawning cue pulse and low summer flows, as well as considerably more SWH and ESH construction than would occur under Alternative 1. Alternative 2 would result in $6.0 million in reduced energy values (i.e., replacement costs of reduced power generation) on average annually over the 15-year period of analysis when compared to Alternative 1, a change of 11.5 percent. Most of this impact (81%) would occur at power plants in the lower river, where the loss in energy values over the 15-year period would increase by 16 percent. The low summer flows in the lower river would cause the largest increases in adverse impacts compared to Alternative 1. Modeled river temperatures during the low summer flow events during the peak summer river temperatures would range from 1 to 3 degrees Fahrenheit higher than under Alternative 1. In addition, higher river temperatures would also adversely impact energy values during non-low summer flow years compared to Alternative 1. The higher amount of SWH and associated shallow water under Alternative 2 relative to Alternative 1 would slightly increase river temperatures under Alternative 2. Overall, adverse impacts to thermal power plants in the lower river would be relatively large and adverse for the summers when low summer flow events would occur, causing reductions in energy values from 17 to 40 percent higher than those expected under Alternative 1.

On average, energy values under Alternative 2 would increase (NED losses would decrease) in the Garrison reach relative to Alternative 1 associated with small benefits to power generation for power plants in this location. Changes in variable costs under Alternative 2 would be negligible when compared to Alternative 1.

Lost capacity occurs if power generation would be impacted during peak summer and winter seasons. Dependable capacity for power plants in the lower river would decrease by an estimated 158 MW relative to Alternative 1. The lost capacity represents 1.3 percent of nameplate capacity for all power plants in the lower river. Losses in capacity values, relative to Alternative 1, would be long-term, large, and adverse, with $22.0 million in recurring annual cost over the period of analysis. There would be negligible impacts to capacity values to power plants in the Garrison reach.

The reductions in power generation would typically occur during peak summer high-temperature periods when multiple plants with simultaneous power generation losses would be affected; these conditions would adversely affect the availability of replacement power, electricity prices (i.e., increase unit energy values), and costs to replace lost capacity, possibly resulting in more adverse impacts than reported here. The NED Analysis for Alternative 2 is summarized in Table 10.

The annual impacts are shown in Figures 5, 6, and 7. Figure 5 shows the annual NED impacts to thermal power plants in both the upper and lower river for the difference from Alternative 1. The results clearly show that overall NED costs or losses for thermal power are predominantly due to impacts to thermal power plants in the lower river. In all years in the analysis, NED losses to thermal power plants would be greater than $20 million relative to Alternative 1 because losses in capacity values under Alternative 2 would be $22 million, which is an annual loss that is applied to each year to estimate the NED impacts.

Table 10. Summary of NED Analysis for Alternative 2

Costs	Upper River[a]	Lower River	All Locations
Effect of Adverse Conditions on Energy Values (Total over 15 years)[b]	$164,901,298	$719,813,684	$884,714,982
Change in Energy Values from Alternative 1 (Total)	-$9,419,612	$100,622,311	$91,202,699
Percent Change in Energy Values from Alternative 1	-5.4%	16.3%	11.5%
Effect of Adverse Conditions on Energy Values (Average Annual)	$10,993,420	$47,987,579	$58,980,999
Change in Energy Values from Alternative 1 (Average Annual)	-$627,974	$6,708,154	$6,080,180
Average Annual Variable Costs[c]	$32,948	NA	$32,948
Change in Annual Variable Costs from Alternative 1	$1,079	NA	$1,079
Average Annual Reduction in Power Generation (MWh)	424,763	1,207,505	1,632,268
Percent of Power Generation relative to Generation with No Adverse Conditions (MWh) (93 million MWh total)	1.8%	1.7%	1.7%
Annual Average Change in Power Generation Reduction Compared to Alternative 1 (MWh)	-24,521	174,305	149,783
Loss in Capacity Values (Annual, Relative to Alternative 1)[d]	$86,338	$21,995,472	NA
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Total)	-$8,108,347	$430,554,385	$422,446,038
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Average Annual)	-$540,556	$28,703,626	$28,163,069

Note: Higher positive values represent higher costs associated with adverse river conditions, while negative values represent lower costs or higher values when compared to Alternative 1.

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one power plant on Lake Sakakawea.

b Energy values represent replacement costs for power generation that is reduced under adverse conditions.

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected.

d Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $136,657/MW-year (Hydropower Analysis Center 2015).

Low summer flow events, as simulated under Alternative 2 for conditions that occurred between 2001 to 2003, would result in large adverse impacts to NED values for thermal power plants in the lower river from relatively higher temperatures, a loss of $45 million in 2003 and loss of $81 million in 2002. The low summer flow events as simulated in 2002 and 2003 would result in small benefits to power plants in the upper river, because reservoirs in these years would have relatively more water resulting in relatively higher releases from Garrison Dam in the fall. To implement the low summer flow events, the reservoirs would not be releasing as much water and would generally be higher than experienced under Alternative 1 during these simulated years, resulting in higher river flows in the fall in the Garrison reach when compared to Alternative 1.

Additional results are shown in Figures 6 and 7. The difference in NED values between Alternative 1 and 2 are plotted and color-coded based on the type of release occurring each year. Figure 6 presents the annual results for the upper river, while Figure 7 presents the annual results for the lower river. Note that the scales of these two figures are very different. Again, the low summer flow years as simulated in 2002 and 2003 would have the largest NED losses relative to Alternative 1. Power plants in the lower river would also experience adverse impacts to power generation and energy values from considerably more SWH constructed under Alternative 2, which slightly raises the peak river temperatures in the summer in the lower river. These impacts would occur throughout the period of analysis because the channel geometry as simulated in the HEC-RAS and ERDC NSM models would be different from the channel geometry under Alternative 1. Again, because capacity would be impacted under Alternative 2 (loss of capacity value of $22 million/year), $22 million is added to the energy values each year to estimate the annual loss in NED values (no variable costs were obtained for power plants in the lower river).

In the upper river, as simulated under Alternative 2 with conditions in 2006, there would be benefits to power plants, which would occur because river flows in the fall would be slightly higher, providing more access to water for operations (days below shut down intake elevation would be higher under Alternative 2). The full spawning cue release as simulated in conditions similar to 2002 and 2003 would provide benefits to power plants in the Garrison reach because of the higher river flows in the fall, as described above.

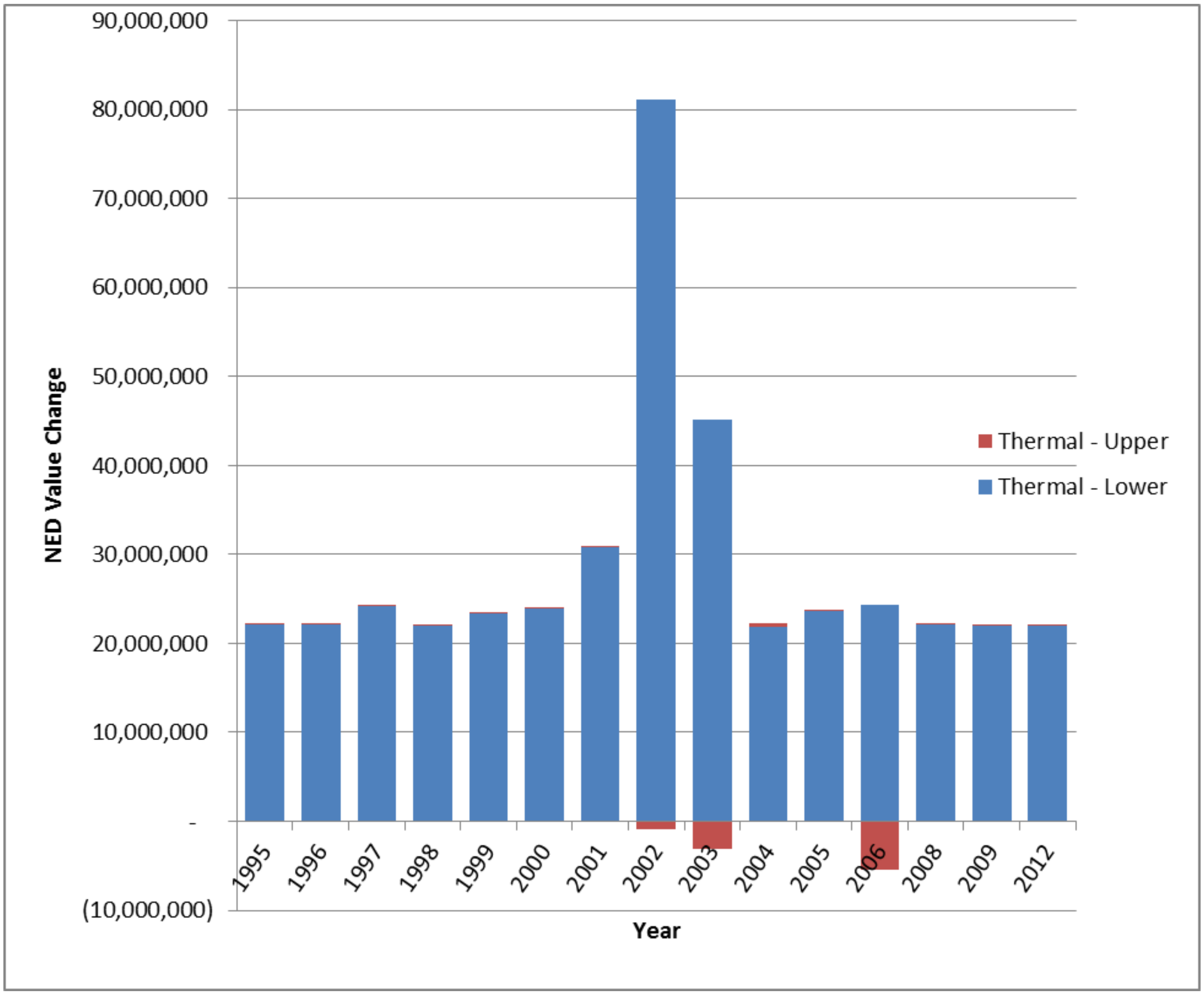

Figure 5. Annual Difference in NED Losses Relative to Alternative 1 for Thermal Power Plants in Upper and Lower River (higher positive values indicate more costs or losses)

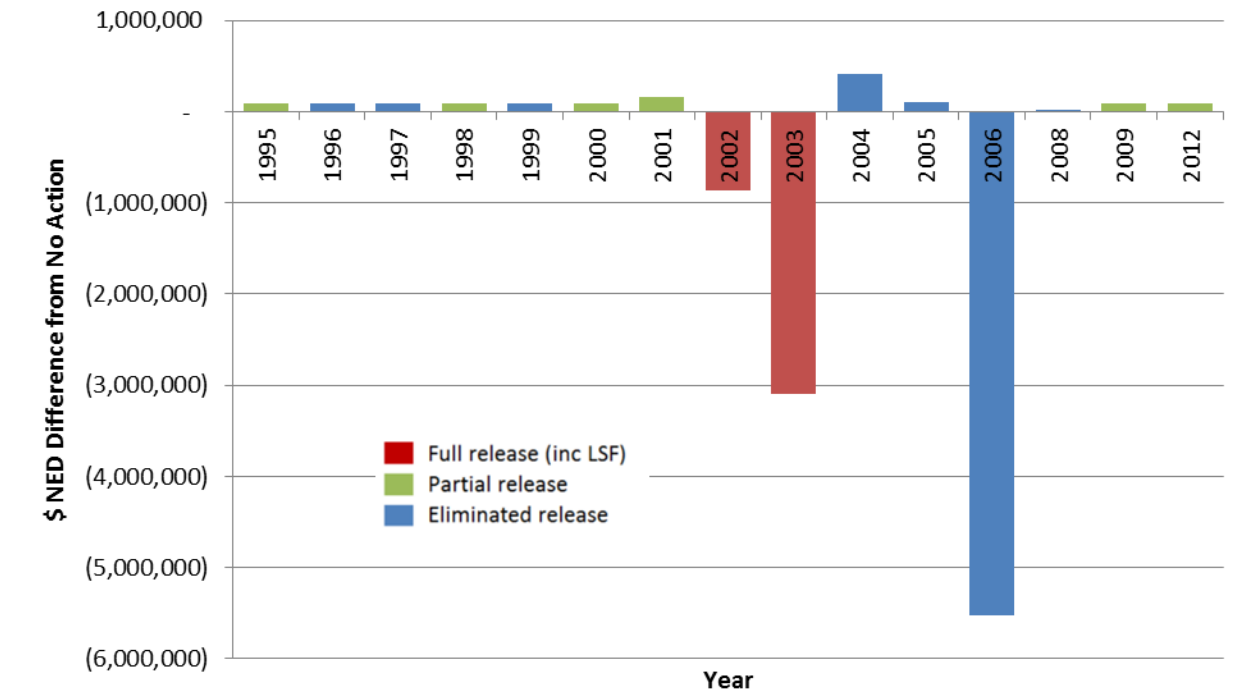

Figure 6. Alternative 2 Difference in NED Losses from Alternative 1 for Thermal Power Plants in the Upper River (higher positive values indicate more costs or losses)

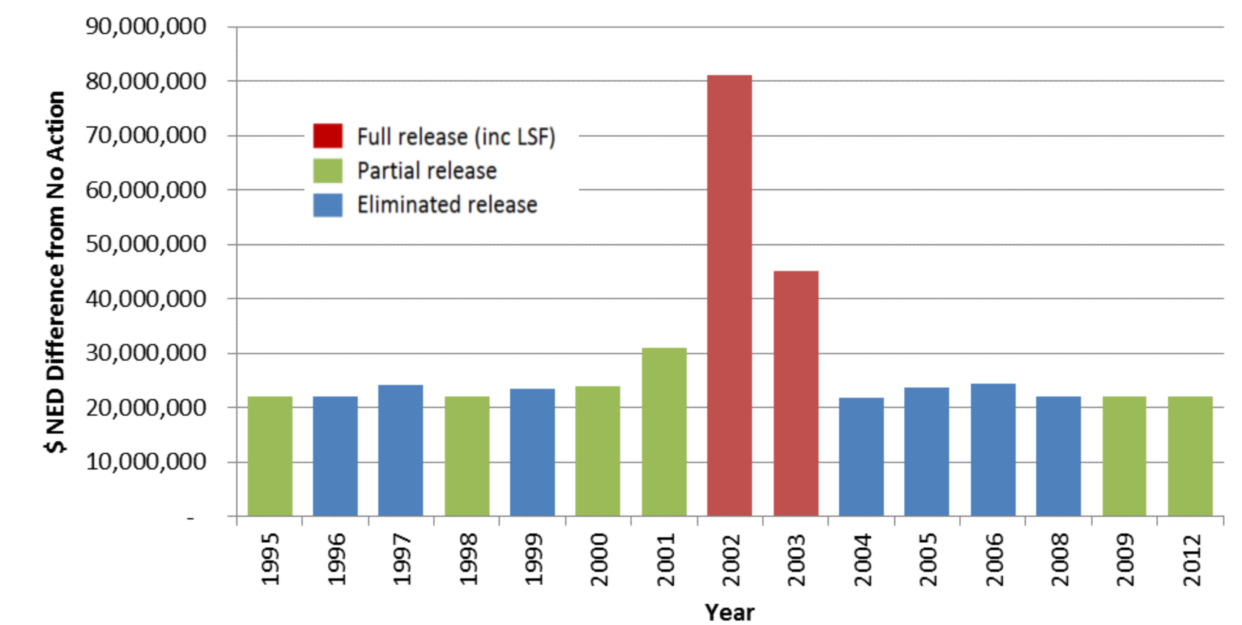

Figure 7. Alternative 2 Difference in NED Losses from Alternative 1 for Thermal Power Plants in the Lower River (higher positive values indicate more costs or losses)

3.4 Alternative 3 – Mechanical Construction Only

Alternative 3 includes mechanical habitat for construction of ESH and IRC habitat. Alternative 3 includes fewer acres of IRC habitat compared to the acres of SWH constructed under Alternative 1 (3,380 acres under Alternative 3 and 3,999 acres under Alternative 1). Alternative 3 would result in slight benefits compared to Alternative 1, with an average annual increase in energy values of $1.7 million (a decrease in the loss) compared to Alternative 1. Table 11 summarizes the NED analysis for Alternative 3. The bulk of the increased benefit would come from power generation increases relative to Alternative 1 in the lower river. The power plants in the lower river would experience slightly lower river temperatures under Alternative 3 compared to Alternative 1 in the summer months because of fewer acres of early life history habitat for the pallid sturgeon, which would result in small benefits to power generation.

Table 11. Summary of NED Analysis for Alternative 3

Costs	Upper River[a]	Lower River	All Locations
Effect of Adverse Conditions on Energy Values (Total over 15 years)[b]	$168,827,502	$599,523,434	$768,350,935
Change in Energy Values from Alternative 1 (Total)	-$5,493,408	-$19,667,938	-$25,161,347
Percent Change in Energy Values from Alternative 1	-3.2%	-3.2%	-3.2%
Effect of Adverse Conditions on Energy Values (Average Annual))	$11,255,167	$39,968,229	$51,223,396
Change in Energy Values from Alternative 1 (Average Annual)	-$366,227	-$1,311,196	-$1,677,423
Average Annual Variable Costs[c]	$28,508	NA	$28,508
Change in Annual Variable Costs from Alternative 1	-$3,361	NA	-$3,361
Average Annual Reduction in Power Generation (MWh)	434,994	997,564	1,432,559
Percent of Power Generation relative to Generation with No Adverse Conditions (MWh) (93 million MWh total)	1.8%	1.4%	1.5%
Change in Average Annual Power Reduction Compared to Alternative 1 (MWh)	-14,290	-35,636	-49,926
Loss in Capacity Values (Annual, Relative to Alternative 1) d	$38,884	$275,181	$314,065
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Total)	-$4,960,571	-$15,540,218	-$20,500,788
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Average Annual)	-$330,705	-$1,036,015	-$1,366,719

Notes: Higher positive values represent higher costs associated with adverse river conditions, while negative values represent lower costs or higher values when compared to Alternative 1.

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one plant on Lake Sakakawea.

b Energy values represent replacement costs for power generation that is reduced under adverse conditions.

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected.

d Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $136,657/MW-year (Hydropower Analysis Center 2015).

Figure 8 shows the annual NED impacts to thermal power plants in upper and lower river as modeled in the NED analysis. Benefits would occur to power generation and thermal power There would also be benefits to power generation compared to Alternative 1 in the upper river due to slightly higher river flows, with on average $366,000 higher (decreased loss in) energy values than would be experienced under Alternative 1. Variable costs for power plants in the upper river would be slightly less than the costs incurred under Alternative 1. Dependable capacity in the peak season in the summer would be higher for plants in the lower river and unchanged for plants in the upper river compared to Alternative 1 with negligible impacts to capacity values. Overall, there would be relatively small benefits to NED values under Alternative 3 because of small increases in river flows in the fall and slight reductions in river temperatures compared to Alternative 1.

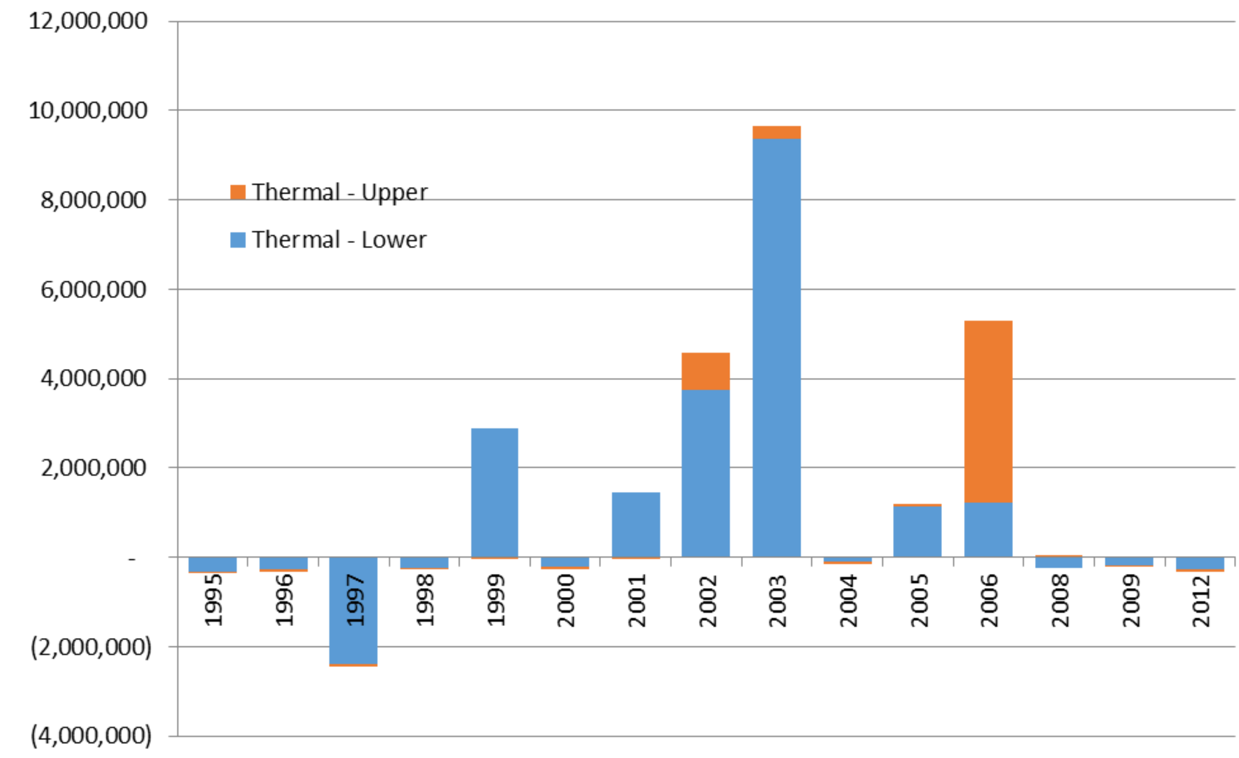

Figure 8. Annual Difference in NED losses under Alternative 3 Relative to Alternative 1 for Thermal Power Plants in Upper and Lower River

NED impacts in the upper and lower river, although the lower river would dominate the overall change in NED impacts for thermal power. Additional results are shown in Figures 9 and 10. The difference in NED values between the alternatives are not plotted and color-coded based on the type of release because flow releases do not occur under Alternative 3. Figure 9 presents the annual results for the upper river, while Figure 10 presents the annual results for the lower river.

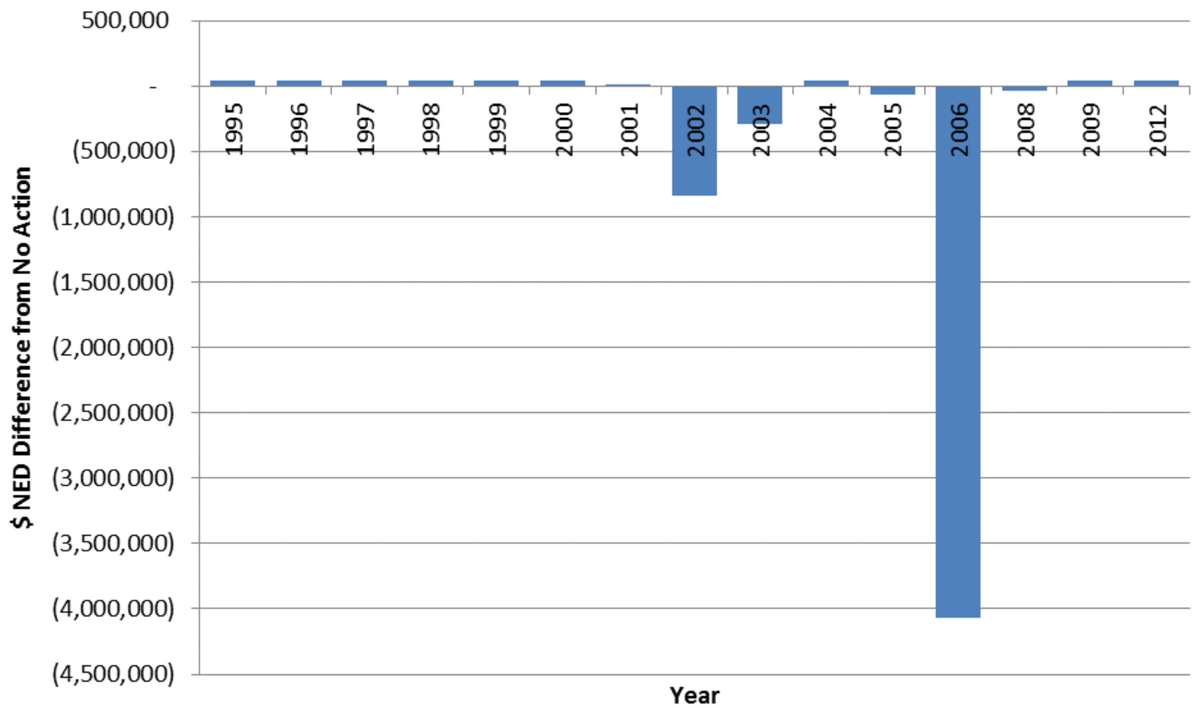

Figure 9. Alternative 3 Difference in NED Losses from Alternative 1 for Thermal Power Plants in the Upper River

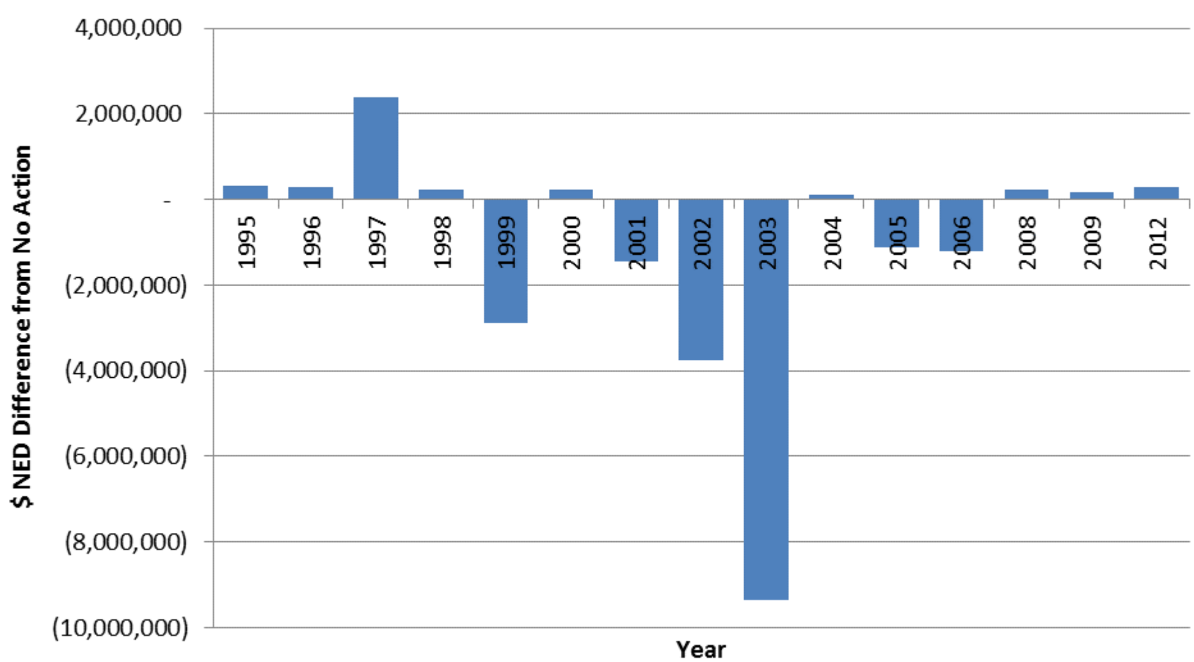

Figure 10. Alternative 3 Difference in NED Losses from Alternative 1 for Power Plants in the Lower River

As modeled in the upper river, there would be benefits to power generation under Alternative 3 compared to Alternative 1 for a number of plants due to slightly higher river flows during drought years similar to those simulated in 2002, 2006, and 2007. In modeled years of 2002 and 2007, the plenary pulse would not occur, with slight increases in reservoir elevations and resulting higher river flows in the fall, which would provide fewer days when river stages would be below shut down intake elevations relative to Alternative 1. Other years, as simulated under Alternatives 3 and 1, would result in negligible changes to NED impacts in the upper river.

The power plants in the lower river would also experience some small benefits to power generation at a number of plants due to slightly lower river temperatures under Alternative 3 compared to Alternative 1 in the summer months because of the fewer acres of early life history habitat for the pallid sturgeon in the lower river under Alternative 3. In the 2000s as simulated under Alternatives 1 and 3, there were no differences in flow releases out of Gavins Point Dam between these alternatives, yet 2001, 2002, 2003, 2005, and 2006 resulted in small benefits to power generation and energy values from slightly higher river temperatures, occurring primarily in the lower part of the lower river, affecting plants in the St. Louis area.

3.5 Alternative 4 – Spring ESH Creating Release

Alternative 4 includes a spring release in April and part of May to create ESH. Compared to Alternative 1, Alternative 4 includes fewer acres of IRC habitat construction compared to the acres of SWH constructed under Alternative 1 in the lower river (3,380 acres under Alternative 4 and 3,999 acres under Alternative 1). Alternative 4 would result in benefits in the lower river and adverse impacts in the upper river, with an average annual decrease in all locations from Alternative 1 of $105,000. The power plants in the lower river would benefit from an increase in average annual energy value of $1.6 million (a decrease in losses). In specific years and conditions, the relatively higher river flows in the summer in the lower river would reduce river temperatures in July when they are at their highest point, resulting in fewer impacts to power generation under Alternative 4 compared to Alternative 1.

Alternative 4 would result in adverse impacts to power generation compared to Alternative 1 in the upper river, with an average annual reduction of $1.6 million or a 15% change compared to Alternative 1. The losses would occur in the fall after a release year as the reservoir system rebalances its storage levels. Overall, adverse impacts to power generation and energy values would be short-term and relatively small to large for the plants in the upper river. Because these reductions in power generation would likely occur during off-peak months of September, October, and November, dependable capacity would not be affected and impacts to capacity values would be negligible under Alternative 4. Variable costs for power plants in the upper river would be slightly higher than the costs incurred under Alternative 1 with a negligible average annual change of $2,654. Table 12 summarizes the NED impacts under Alternative 4.

Table 12. Summary of NED Analysis for Alternative 4

Costs	Upper River[a]	Lower River	All Locations
Effect of Adverse Conditions on Energy Values (Total over 15 years)[b]	$200,499,564	$594,590,588	$795,090,152
Change in Energy Values from Alternative 1 (Total)	$26,178,654	-$24,600,784	$1,577,870
Percent Change in Energy Values from Alternative 1	15.0%	-4.0%	0.2%
Effect of Adverse Conditions on Energy Values (Average Annual)	$13,366,638	$39,639,373	$53,006,010
Change in Energy Values from Alternative 1 (Average Annual)	$1,745,244	-$1,640,052	$105,191
Average Annual Variable Costs[c]	$34,523	NA	$34,523
Change in Annual Variable Costs from Alternative 1	$2,654	NA	$2,654
Average Annual Reduction in Power Generation (MWh)	516,747	990,558	1,507,305
Percent of Power Generation relative to Generation with No Adverse Conditions (MWh) (93 million MWh total)	2.2%	1.4%	1.6%
Change in Average Annual Power Reduction Compared to Alternative 1 (MWh)	67,462	-42,642	24,821
Loss in Capacity Values (Relative to Alternative 1)[d]	$38,884	$275,181	$314,065
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Total)	$26,801,724	-$20,473,063	$6,328,661
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Average Annual)	$1,786,782	-$1,364,871	$421,911

Note: Higher positive values represent higher costs associated with adverse river conditions, while negative values represent lower costs or higher values when compared to Alternative 1.

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one plant on Lake Sakakawea.

b Energy values represent replacement costs for power generation that is reduced under adverse conditions.

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected.

d Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $136,657/MW-year (Hydropower Analysis Center 2015)

Figure 11 shows the annual NED impacts to thermal power plants in upper and lower river. As modeled, there would not be a lot of changes in the NED impacts relative to Alternative 1 in most of the years under the 15-year period of analysis. However, there would be benefits in a year similar to conditions simulated in 2003 in the lower river from relatively higher summer flows. There would also be adverse impacts in the upper river in a year similar to conditions simulated under Alternative 4 in 2009.

Additional results are shown in Figures 12 and 13. The difference in NED values between Alternative 1 and 4 are plotted and color-coded based on the type of release occurring each year. Figure 12 presents the annual results for the upper river, while Figure 13 presents the annual results for the lower river. Almost all of the adverse impact to power plants in the upper river would occur in one year, 2009. In the upper river, the simulated partial release in 2009 would result in relatively lower flows in the fall in the Garrison reach, causing adverse impacts to power generation from river stages falling below shut down intake elevations more than under Alternative 1. Power generation losses relative to Alternative 1 were over 1 million MWH during the fall season as simulated in this year. Four power plants would be affected by lower river flows similar to those that occurred in the year 2009, with two plants each incurring over $10 million in energy value losses compared to Alternative 1 under conditions simulated in 2009. Because these reductions in power generation would occur during off-peak months of September, October, and November, dependable capacity would not be anticipated to be impacted.

The power plants in the lower river would benefit from an increase in total energy values (a decrease in losses) of $24.6 million over the 15-year period of analysis, $19 million of which would occur with conditions similar to those simulated under Alternative 4 in 2003. As simulated in 2003, a full release occurs in the spring and higher releases out of Gavins Point Dam continue in May, June, and most of July of about 5,000 cfs higher under Alternative 4 compared to Alternative 1. These small increases in river flows in the lower river would reduce river temperatures in July when they are at their highest point, resulting in fewer adverse impacts to power generation under Alternative 4 compared to Alternative 1.

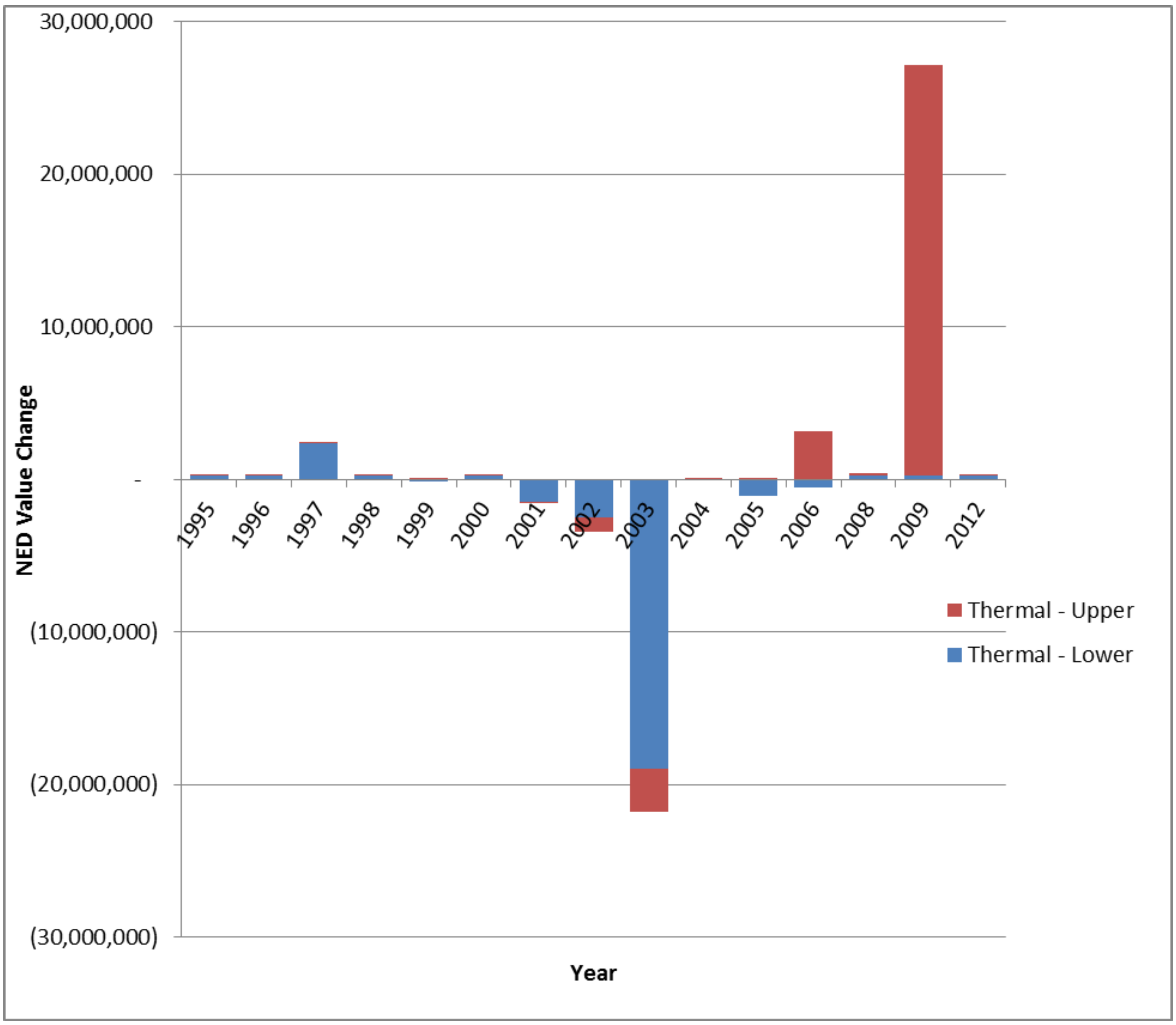

Figure 11. Annual Difference in NED Losses Relative to Alternative 1 for Thermal Power Plants in Upper and Lower River

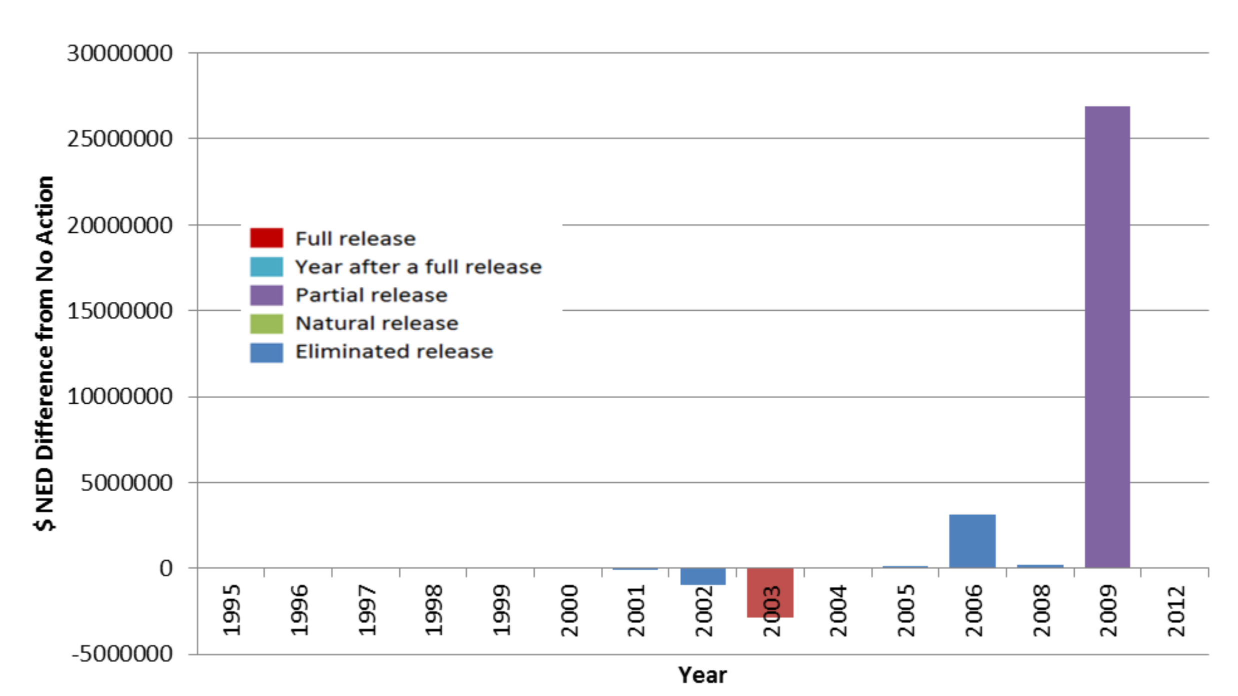

Figure 12. Alternative 4 Difference in NED Losses from Alternative 1 for Thermal Power in the Upper River

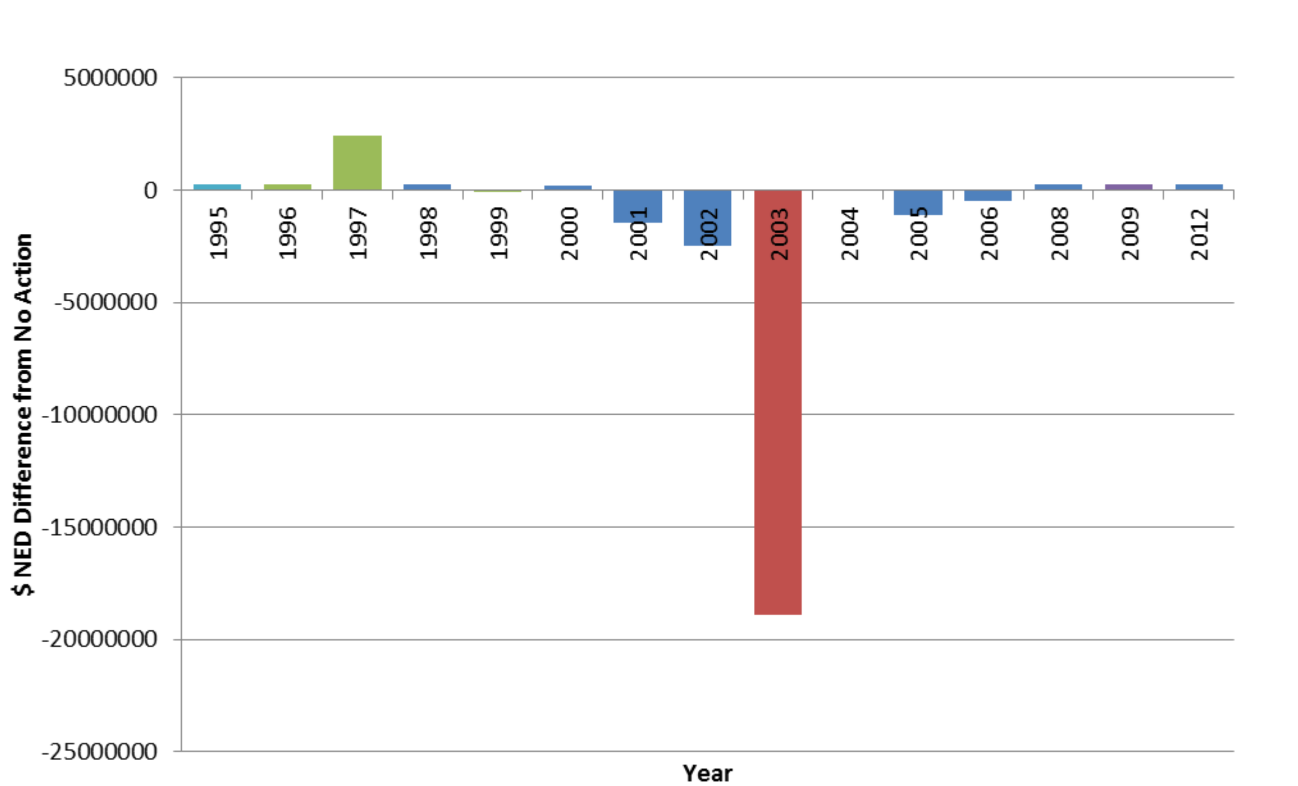

Figure 13. Alternative 4 Difference in NED Losses from Alternative 1 for Thermal Power Plants in the Lower River

3.6 Alternative 5 – Fall ESH Creating Release

Alternative 5 includes a fall release in October and November to create ESH; the fall release (full and partial) does not occur in the 15-year period of analysis, making the estimation of impacts to power plants during and following the flow releases difficult in this short period of analysis. Alternative 5 includes fewer acres of IRC habitat compared to the acres of SWH constructed under Alternative 1 in the lower river. ESH construction would include an average of 309 aces per year, while Alternative 1 would result in an average of 107 per year in years when construction occurs.

Alternative 5 results in beneficial impacts to NED compared to Alternative 1, with an average annual increase in energy values (decreased loss) of $1.4 million. Table 13 summarizes the NED analysis for thermal power plants. The Missouri River power plants in the lower river would experience an increase of $1.0 million in energy values per year when compared to energy values under Alternative 1. The beneficial effects would be from slight reductions in peak summer river temperatures from fewer acres of early life history habitat for the pallid sturgeon (IRC) constructed under Alternative 5. In the upper river, Alternative 5 would result in an average annual increase of $350,000 compared to Alternative 1. Higher fall river flows would account for the small benefits in power generation and energy values relative to Alternative 1.

Variable costs for power plants in the upper river would be slightly lower than the costs incurred under Alternative 1 with negligible change in costs compared to Alternative 1. Alternative 5 would result in negligible impacts to capacity values.

Figure 14 shows the annual NED impacts to thermal power plants in upper and lower river. In a number of years, there would be benefits to thermal power plants in the upper and lower river. However, there would be benefits in a year similar to conditions simulated in 2003 in the lower river from relatively higher summer flows. There would also be adverse impacts in the upper river in a year similar to conditions simulated under Alternative 4 in 2009.

Additional results are shown in Figures 15 and 16. The difference in NED values between Alternative 1 and 4 are plotted and color-coded based on the type of release occurring each year. Figure 15 presents the annual results for the upper river, while Figure 16 presents the annual results for the lower river. There are no clear associations with impacts associated with the release year or year after a release, although the 15-year period of analysis does not include a full release year. In the upper river, plants would experience benefits to power generation and energy values as simulated under Alternatives 1 and 5 under similar conditions to 2002 and 2006. Total increases in energy values would be $5.2 million relative to Alternative 1 over the 15-year period of analysis. Within the model, two simulated years, 2002 and 2006, would account for increases of $1 and $4 million, respectively, when fall river flows would be higher under Alternative 5 than under Alternative 1.

The Missouri River power plants in the lower river would benefit from an increase in energy values (decrease in losses) of $15.4 million of the 15-year period of analysis, $9.3 million of which would occur in under a modeled year similar to conditions in 2003 during the summer months. In 2003, there were no changes in the simulated releases from Gavins Point Dam under Alternatives 1 and 5. The beneficial effects are from slight reductions in peak summer river temperatures from fewer acres of SWH constructed under Alternative 5 relative to Alternative 1.

Table 13. Summary of NED Analysis for Alternative 5

Costs	Upper River[a]	Lower River	All Locations
Effect of Adverse Conditions on Energy Values (Total over 15 years)[b]	$169,105,674	$603,786,958	$772,892,632
Change in Energy Values from Alternative 1 (Total)	-$5,215,236	-$15,404,414	-$20,619,650
Percent Change in Energy Values from Alternative 1	-3.0%	-2.5%	-2.6%
Effect of Adverse Conditions on Energy Values (Average Annual))	$11,273,712	$40,252,464	$51,526,175
Change in Energy Values from Alternative 1 (Average Annual)	-$347,682	-$1,026,961	-$1,374,643
Average Annual Variable Costs[c]	$29,336	NA	$29,336
Change in Annual Variable Costs from Alternative 1	-$2,532	NA	-$2,532
Average Annual Reduction in Power Generation (MWh)	435,801	1,004,819	1,440,620
Percent of Power Generation relative to Generation with No Adverse Conditions (MWh) (93 million MWh total)	1.8%	1.4%	1.5%
Change in Average Annual Power Reduction Compared to Alternative 1 (MWh)	-13,483	-28,381	-41,864
Loss in Capacity Values (Relative to Alternative 1)[d]	$38,884	$275,181	$314,065
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Total)	-$4,669,966	-$11,276,693	-$15,946,659
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Average Annual)	-$311,311	-$751,780	-$1,063,111

Note: Higher positive values represent higher costs associated with adverse river conditions, while negative values represent lower costs or higher values when compared to Alternative 1.

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one plant on Lake Sakakawea.

b Energy values represent replacement costs for power generation that is reduced under adverse conditions.

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected.

d Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $136,657/MW-year (Hydropower Analysis Center 2015).

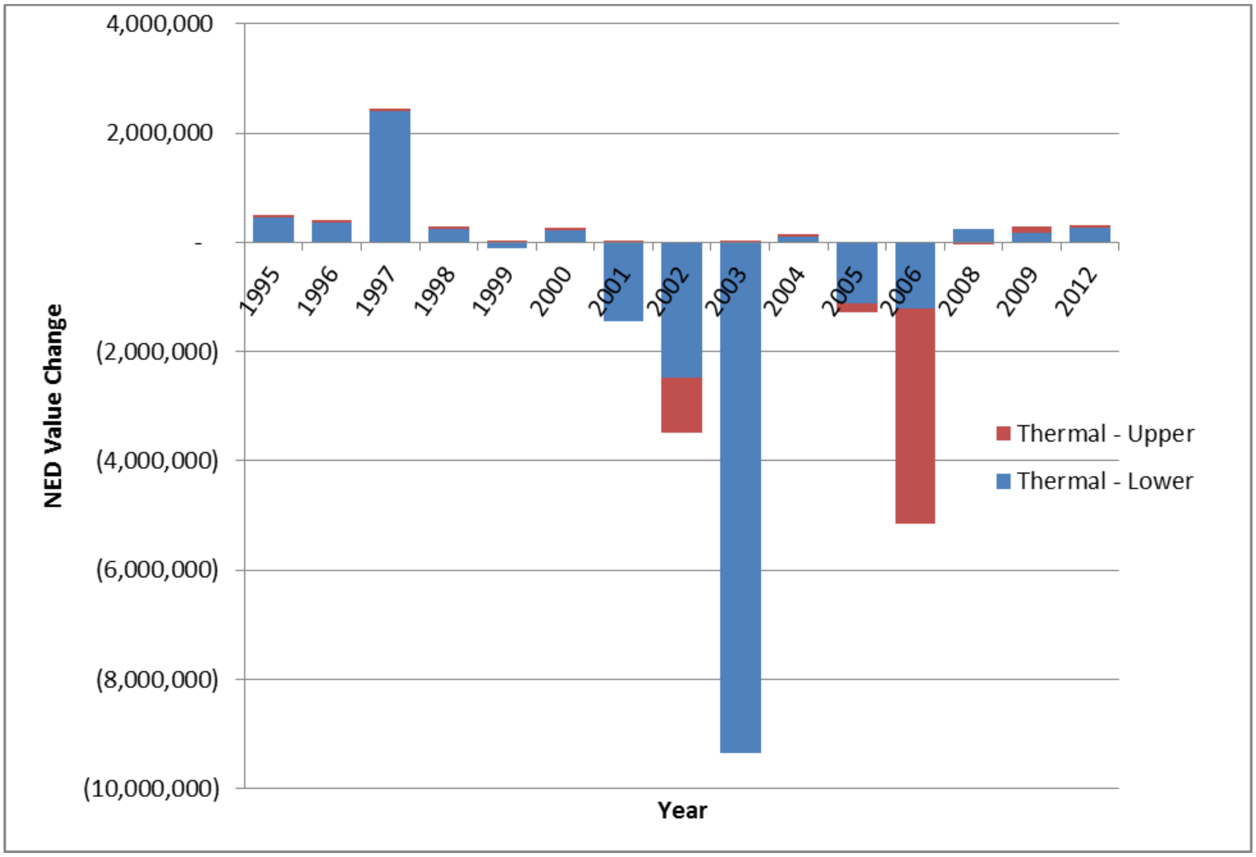

Figure 14. Annual Difference in NED Losses Relative to Alternative 1 for Thermal Power Plants in Upper and Lower River

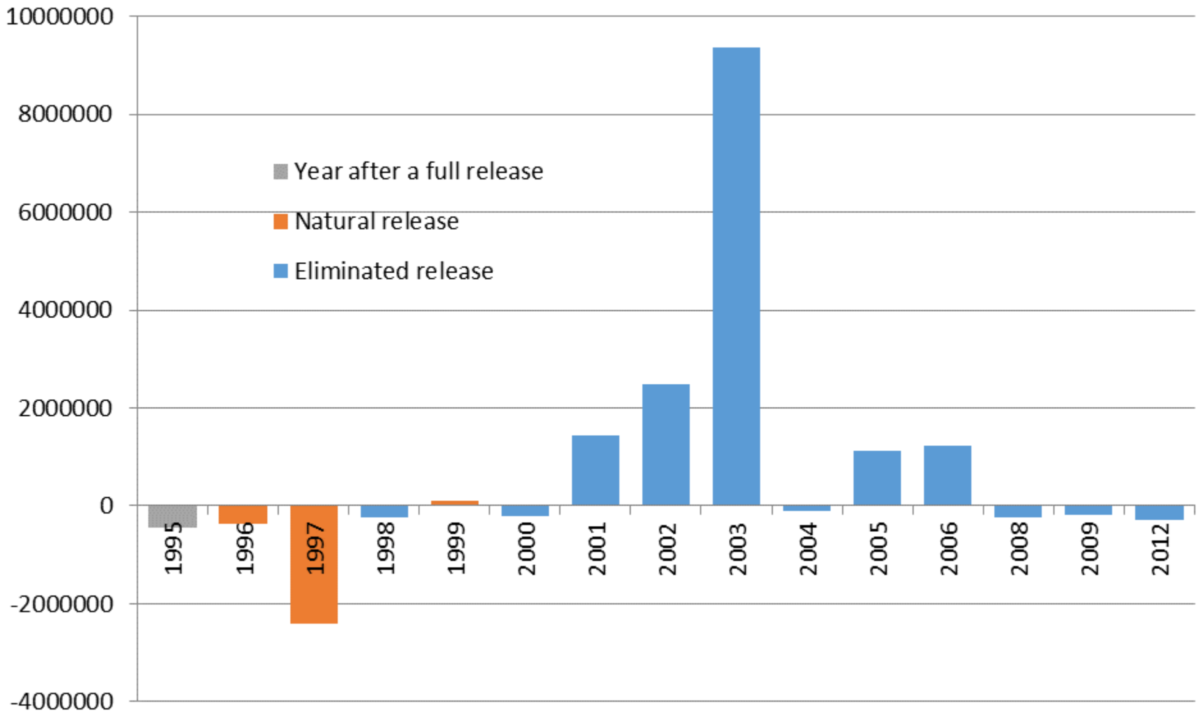

Figure 15. Alternative 5 Difference in NED Losses from Alternative 1 for Thermal Power Plants in the Upper River

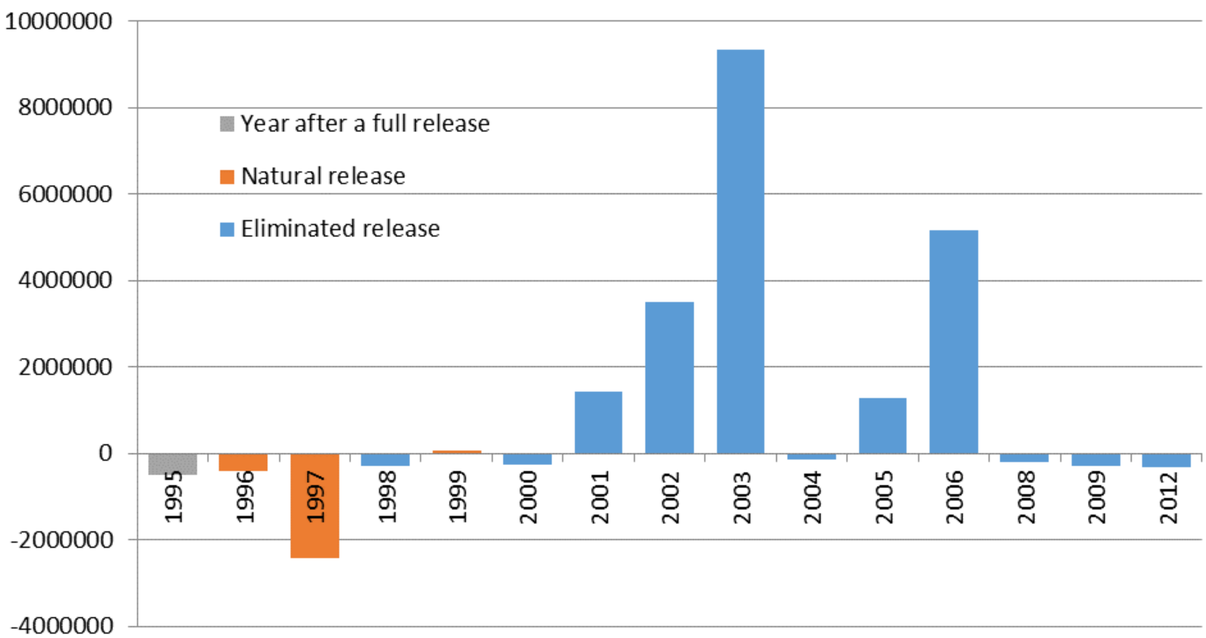

Figure 16. Alternative 5 Difference in NED Losses from Alternative 1 for Thermal Power in the Lower River

3.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Alternative 6 includes a bi-modal spawning cue in March and May to benefit the pallid sturgeon. Alternative 6 includes fewer acres of IRC habitat compared to the acres of SWH constructed under Alternative 1 in the lower river (3,380 acres under Alternative 6 and 3,999 acres under Alternative 1). However, ESH construction would include an average of 303 aces per year, while Alternative 1 would result in an average of 107 per year in years when construction occurs. Alternative 6 results in beneficial impacts to NED impacts compared to Alternative 1, with an average annual increase of energy values (decrease loss) of $2.4 million compared to Alternative 1 (Table 14). Most of the benefit would occur in the lower river, with an annual average increase of $2.2 million, the bulk of which would occur during a simulated full release year. Alternative 6 would result in very small beneficial impacts on average to power generation at power plants in the upper river when compared with Alternative 1, with an annual average increase in energy values of $144,000 compared to Alternative 1. Overall, there would be relatively small benefits to power plant generation and energy values under Alternative 6 due to small increases in river flows in the fall and winter that benefit access for intake cooling water and provide lower river temperatures and increase power generation relative to Alternative 1.

Variable costs for power plants in the upper river would be lower than the costs incurred under Alternative 1, with negligible change in costs compared to Alternative 1. Capacity values under Alternative 6 would be adversely affected under Alternative 6, resulting in $1.0 million in lost capacity values, with most of the impact occurring in the lower river. The adverse impacts to capacity values would occur at two plants in relatively drier years when the reservoir system is rebalancing in the year or two following a spawning cue release. Impacts to capacity values would be relatively long-term, small and adverse.

Figure 17 shows the annual NED impacts to thermal power plants in upper and lower river. As modeled, two years would drive the changes in the NED impacts relative to Alternative 1 in the 15-year period of analysis. There would be benefits in a year similar to conditions simulated in 2003 in the lower river from relatively higher river temperatures flows from a full release, and adverse impacts as simulated in 2006 to plants in the upper river from lower river flows in the fall in this year.

Additional results are shown in Figures 18 and 19. The difference in NED values between Alternative 1 and 6 are plotted and color-coded based on the type of release occurring each year. Figure 18 presents the annual results for the upper river, while Figure 19 presents the annual results for the lower river.

There would be beneficial impacts to power generation compared to Alternative 1 in the upper river for a number of plants, with years similar to 2003 and 2009 providing the bulk of the benefits. As simulated under a year similar to 2003, there would be approximately $3.5 million in increased energy value compared to Alternative 1 because of relatively higher river flows in the fall compared to Alternative 1. In the upper river, there would be adverse impacts to power generation and energy values in one simulated year under Alternative 6 -- 2006 -- with $5.5 million in more energy value losses compared to Alternative 1 due to slightly lower river flows relative to Alternative 1 in the Garrison Dam to Lake Sakakawea reach as the reservoir system rebalanced following the 2003 spawning cue release. On average across all years within the 15-year period of analysis, there would be an increase in NED values (decrease in losses) of $9,795 on average.

Table 14. Summary of NED Analysis for Alternative 6

Costs	Upper River[a]	Lower River	All Locations
Effect of Adverse Conditions on Energy Values (Total over 15 years)[b]	$172,158,508	$586,084,116	$758,242,623
Change in Energy Values from Alternative 1 (Total)	-$2,162,403	-$33,107,257	-$35,269,659
Percent Change in Energy Values from Alternative 1	-1.2%	-5.3%	-4.4%
Effect of Adverse Conditions on Energy Values (Average Annual))	$11,477,234	$39,072,274	$50,549,508
Change in Energy Values from Alternative 1 (Average Annual)	-$144,160	-$2,207,150	-$2,351,311
Average Annual Variable Costs[c]	$28,050	NA	$28,050
Change in Annual Variable Costs from Alternative 1	-$3,818	NA	-$3,818
Average Annual Reduction in Power Generation (MWh)	443,479	977,056	1,420,535
Percent of Power Generation relative to Generation with No Adverse Conditions (MWh) (93 million MWh total)	1.9%	1.4%	1.5%
Change in Average Annual Power Reduction Compared to Alternative 1 (MWh)	-5,805	-56,144	-61,950
Loss in Capacity Values (Relative to Alternative 1)[d]	$138,183	$915,719	$1,053,903
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Total)	-$146,929	-$19,371,465	-$19,518,394
Change in Energy Values, Capacity Values, and Variable Costs from Alternative 1 (Average Annual)	-$9,795	-$1,291,431	-$1,301,226

Note: Higher positive values represent higher costs associated with adverse river conditions, while negative values represent lower costs or higher values when compared to Alternative 1.

a The upper river includes five power plants in the Garrison Dam to Lake Oahe river reach and one plant on Lake Sakakawea.

b Energy values represent replacement costs for power generation that is reduced under adverse conditions.

c Variable costs include operations and maintenance costs incurred under adverse conditions when power generation is not affected.

d Capacity values represent an annualized capital cost to replace the estimated lost capacity; the unit capacity value was $136,657/MW-year (Hydropower Analysis Center 2015).

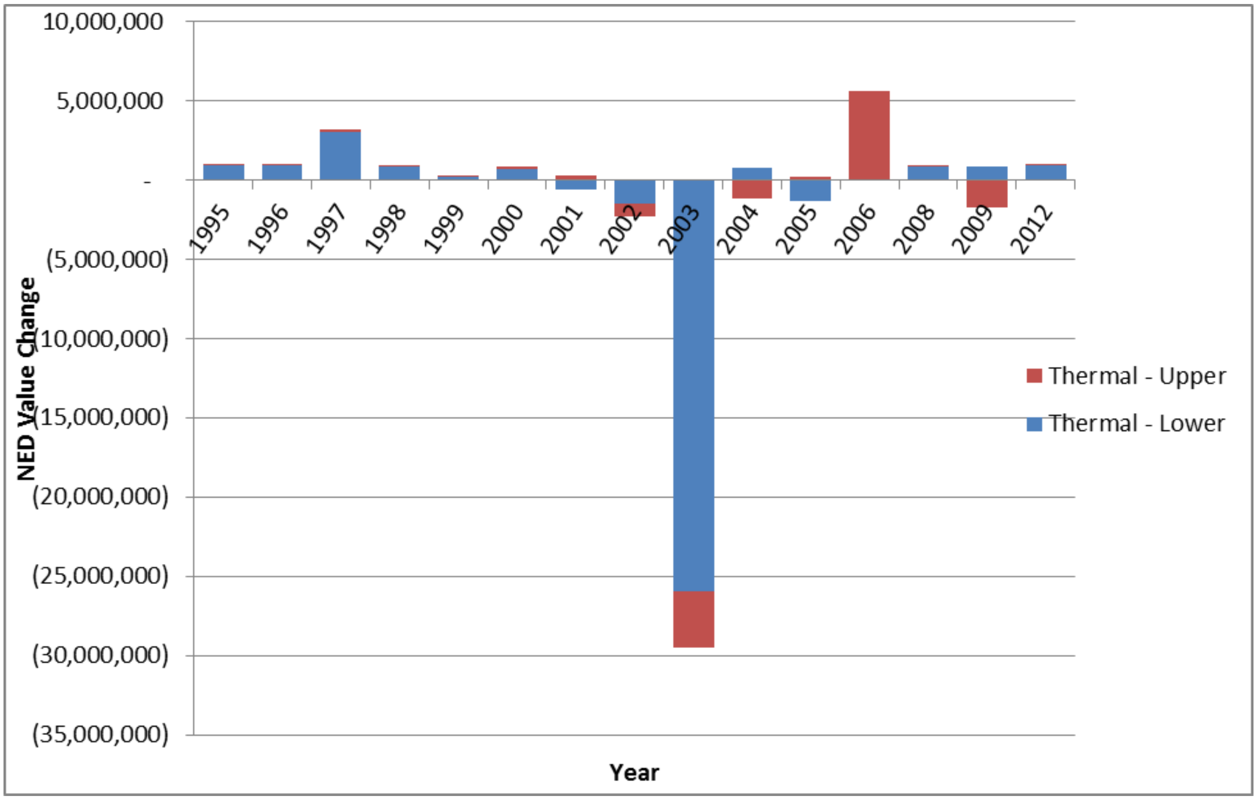

Figure 17. Annual Difference in NED Losses Relative to Alternative 1 for Thermal Power Plants in Upper and Lower River

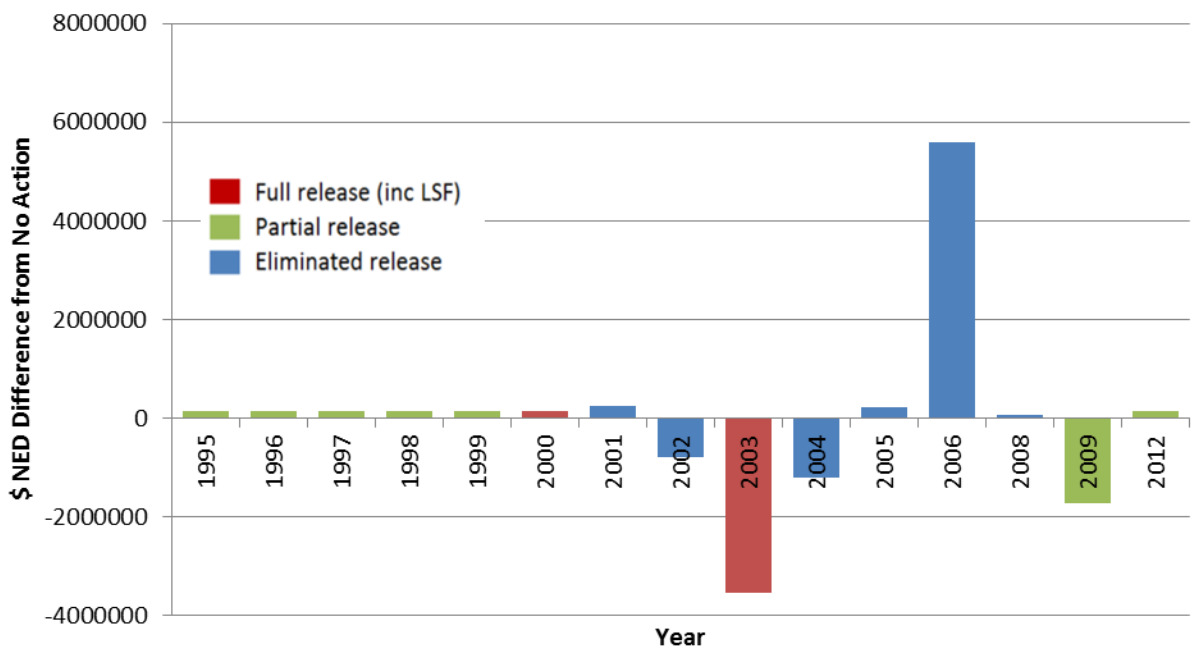

Figure 18. Alternative 6 Difference in NED Losses from Alternative 1 for Thermal Power Plants in the Upper River

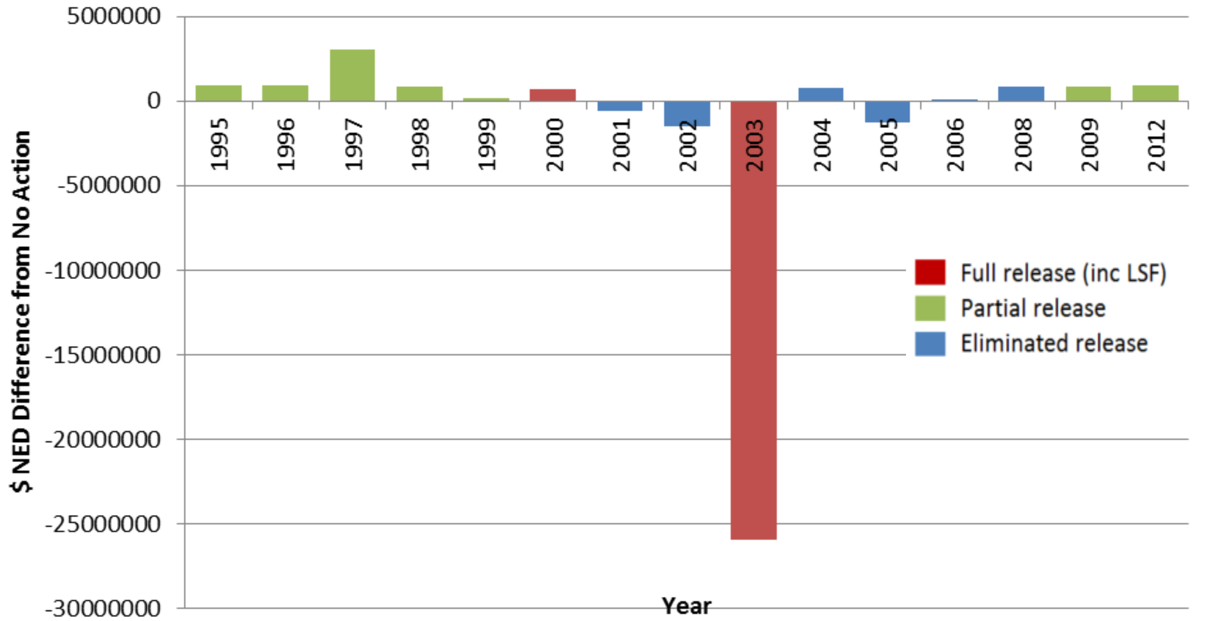

Figure 19. Alternative 6 Difference in NED Losses from Alternative 1 for Thermal Power Plants in the Lower River

The power plants in the lower river would benefit from an increase in total energy values of $33.1 million relative to Alternative 1 across the 15-year period of analysis, $26 million of which would occur in a year similar to conditions simulated in 2003. In 2003, a simulated full spawning cue release would occur in the spring and higher releases out of Gavins Point Dam continue in May, June, and most of July, with approximately 5,000 cfs higher under Alternative 6 compared to Alternative 1. These relatively higher summer river flows in the lower river would reduce river temperatures in July when they would be at their highest point, resulting in fewer impacts to power generation under Alternative 6 compared to Alternative 1.

Dependable capacity in the peak season in the summer would be higher for plants in the lower river under Alternative 6, and negligible for plants in the upper river compared to Alternative 1. However, capacity values under Alternative 6 would be adversely affected with most of the impact occurring in the lower river. Although overall dependable capacity increases under Alternative 6 for the lower river power plants, there would be two plants that experience decreases in capacity of 6.7 MW under Alternative 6 compared to Alternative 1, resulting in an annual loss in capacity values of $915,719 relative to Alternative 1. Most of the capacity would be impacted for these two plants from decreased generation simulated under Alternative 6 in years with similar conditions to 2001, when there would be very slightly lower releases from Gavins Point Dam under Alternative 6 compared to Alternative 1 as the reservoir system rebalances after the full spawning cue release in 2000.

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

If both hydropower and thermal power generation are affected during peak and critical periods, there is a potential for coupled effects of the two and amplified impacts from Management Plan actions. Power generation estimates for both hydropower and thermal power were compared season by peak season (for every year) over the 15-year period (1995-2012 not including 2007, 2010, and 2011) to evaluate the potential for coupled effects to wholesale electricity prices. Under alternative 2, the coupled effects could potentially occur during summer months when low summer flow events would occur, which were simulated to occur under Alternative 2 in 2002 and 2003. During the low summer flow events, both hydropower and thermal power are experiencing reductions in generation during a season when demand for electricity is also typically high, which could lead to higher energy values than reported above with more adverse impacts to thermal power plants when compared to Alternative 1.

The potential for coupled effects is not expected to occur as a result of any Management Plan actions under Alternatives 3, 4, 5, and 6 because there are generally benefits to power generation under these alternatives for power generation. Alternative 4 could result in coupled effects with reductions from both hydropower and thermal power, although these conditions would occur in the fall months. Because the reductions in power generation from hydropower and thermal power would occur in the fall and demand for electricity is typically low during that period, there are not anticipated to be coupled impacts on wholesale electricity prices.

4.0 Regional Economic Development Results

This section provides the results of the RED analysis. A summary of results across all alternatives is presented first followed by a detailed description of the results by alternative.

4.1 Summary Across Alternatives

The focus of the RED analysis for thermal power is on the potential of the MRRMP-EIS alternatives to impact wholesale energy prices and consumer electricity rates, which could have implications for household and business spending and regional economic conditions. Any changes in retail electricity rates could impact household and business spending, with implications for jobs and income in regional economies. If consumers must spend more of their income on higher electricity rates, they would have less disposable income to spend on other goods and services, which could adversely impact jobs and income in affected industries.

The RED analysis used power generation information from the SPP and MISO Regional Transmission Organizations (RTOs) and consultation with RTO experts to describe the potential impacts of the reductions in power generation on wholesale electricity prices and how changes to those prices could impact consumer electricity rates that are set by retail electricity providers. The NED results indicate that a number of plants would likely have to shut down or de-rate temporarily under all of the alternatives as a result of low flow or river stages or increased river temperatures. As described in Section 2.5, wholesale electricity prices could be affected if multiple plants experience reductions in power generation during peak power demand seasons (summer and winter); the prices that retail electricity providers pay for electricity would temporarily increase because the next marginal energy producer would likely charge more per unit of energy produced. In addition, when reductions in power generation occur in the peak periods during adverse conditions (i.e., high river temperature), the price increases are likely to be much higher than if the generation was reduced during off-peak times (i.e., fall and spring). In this situation, when capacity in the RTO is limited, some of the highest-cost resources would need to be brought online, potentially increasing wholesale electricity prices. If the Missouri River thermal power plants must reduce power generation for a long period of time or on a re-occurring basis, the wholesale price that retail electrical providers pay for their electricity could increase, and the providers may then have the rationale to petition state utility commissions for an increase in consumer electricity rates.

Tables 15 and 16 present the reductions in power generation for the worst case year under the MRRMP-Draft EIS alternatives and as a percentage of the RTO power generation. The only notable reductions in power generation relative to Alternative 1 during peak seasons occur under Alternative 2 in the summer in both MISO and SPP markets. Under Alternative 2, the worst case reduction in power generation under Alternative 2 for the plants in SPP accounts for approximately 3.8 percent of SPP generation in the summer, about 2 percent more than under Alternative 1. The worst case reduction in power generation under Alternative 2 for the plants in MISO accounts for approximately 3.4 percent of MISO generation in the summer, an increase of 0.7 percent compared to Alternative 1.

Adverse impacts to power generation under Alternative 2 relative to Alternative 1 would be large and possibly significant when low summer flow events would occur (two years are simulated to have low summer flow events under Alternative 2 in 2002 and 2003). Further analysis of the impacts to power generation during the summers of 2002 and 2003 indicate that high river temperatures tend to affect multiple plants simultaneously in the lower river in one or two periods within the summer season. During these periods, it is likely that wholesale electricity prices would increase, and potentially, with re-occurring low summer flow events under Alternative 2, there would be the potential for higher retail electricity prices in the long-term. Higher electricity rates under Alternative 2 would result in adverse impacts to household and business spending because with higher electricity rates, households and business would have less money to spend on personal or business expenses. With less spending, there could be impacts to regional economic conditions under Alternative 2. Impacts under Alternatives 3, 4, 5, and 6 would result in negligible impacts to consumer electricity rates and regional economic conditions compared to Alternative 1 because any adverse impacts to power generation would occur during the fall months, during off-peak seasons.

Table 15. Worst-Case Year Power Generation Reduction by Season under the MRRMP Draft-EIS Alternatives and as a Percent of SPP Generation

Season	Alternatives					
	1	2	3	4	5	6
Worst-Case Year Power Generation Reductions under the MRRMP-EIS Alternatives (MWH)						
Winter	210,013	210,013	210,013	206,225	210,013	210,013
Spring	92,612	88,044	81,174	81,174	81,174	81,174
Summer	724,361	1,754,007	658,386	664,610	664,610	663,170
Fall	212,655	219,476	208,800	238,270	208,800	234,415
Percent of Power Generation Reduction as a Percent of SPP Generation						
Winter	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Spring	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Summer	1.6%	3.8%	1.4%	1.4%	1.4%	1.4%
Fall	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%

Source: SPP 2014 and 2015.

Table 16. Worst-Case Year Power Generation Reductions by Season under the MRRMP-EIS Alternatives and as a Percent of MISO Generation

Season	Alternatives					
	1	2	3	4	5	6
Worst-Case Year Power Generation Reductions under the MRRMP-EIS Alternatives (MWH)						
Winter	2,982	5,964	5,964	4,473	2,982	5,964
Spring	12,184	5,538	11,076	6,646	11,076	6,646
Summer	2,757,688	3,401,385	2,664,205	2,688,962	2,688,962	2,688,962
Fall	2,799,889	2,801,308	2,799,888	2,799,888	2,799,888	2,801,308
Percent of Power Generation Reduction as a Percent of MISO Generation						
Winter	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Spring	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Summer	2.7%	3.4%	2.6%	2.7%	2.7%	2.7%
Fall	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%

Source: MISO 2016

4.2 Alternative 1 – No Action

Under Alternative 1, adverse impacts to power generation occur, most of which occurs in the mid-2000s, when drought conditions affect river flows and temperatures. Most of the worst years occur when river temperatures are relatively higher in the lower river and river flows in the fall and winter fall below critical operating conditions in the mid-2000s. In the worst-case summer, power generation in the SPP RTO would be reduced by 724,361 MWh. This loss of generation represents a 1.6 percent of SPP generation during the summer season with no adverse conditions Table 17). Within the MISO RTO, power generation from all power plants during the worst-case summer season would be reduced by 2,757,688 MWh, or 2.7 percent of total MISO power generation. During the winter peak power season for the Missouri River power plants in SPP, there would be up to 0.5 percent of SPP's total generation affected during the worst-case winter season. Within the MISO RTO the reduction in power generation in the winter represent less than 0.1 percent of total generation in MISO during the winter.

Although there would be reduced power generation in non-peak seasons when compared to no adverse impacts to river conditions, replacement generation would likely cost considerably less than during peak seasons and would not affect the wholesale electricity prices for retail electricity providers. Therefore, reductions in power during these off-peak seasons would not likely contribute to higher consumer electricity rates.

The reduction in Missouri River power generation compared to no adverse conditions under Alternative 2 as a percent of total generation in the summer is a relatively small percent (1.6 – 2.7%). However, these reductions would likely occur during one period of time during peak power demand seasons, when replacement power from MISO, SPP or other markets may be scarce. In addition, these impacts occur over multiple years during the period of analysis, supporting rationale for retail electricity providers to increase consumer electricity rates compared to current rates because of the higher prices to purchase the wholesale electricity. As a result, there could be relatively large, but temporary, reductions in power generation that could increase the price that retail electricity providers pay for wholesale electricity, which could cause providers to increase consumer electricity rates in the long-term. The impacts to consumer electricity rates are likely to be long-term and adverse, although the exact impact on electricity prices (wholesale prices) and consumer electricity rates are uncertain. If retail electricity rates increase in the long-term, there may be impacts to household and business spending with higher rates there would be less disposable income to spend on other goods and services in the community or region, causing adverse effects to local and regional economies.

Table 17. Worst-Case Year Reduction in Power Generation by RTO and Season under Alternative 1

Season	SPP	MISO
Reduction in Power Generation under the MRRMP-EIS Alternative (MWH)		
Winter	210,013	2,982
Spring	92,612	12,184
Summer	724,361	2,757,688
Fall	212,655	2,799,889
Percent of Power Generation Reduction as a Percent of the RTO's Generation		
Winter	0.5%	0.0%
Spring	0.1%	0.0%
Summer	1.6%	2.7%
Fall	0.3%	1.5%

Source: SPP 2015; SPP 2016; MISO 2014; MISO 2016

4.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Alternative 2 would result in large and possibly significant impacts to power generation and NED impacts, which would be driven by changes in power generation from plants in the lower river affected by low summer flow events and a higher prevalence of SWH. In the worst-case year, as simulated in 2002, power generation for power plants in the SPP RTO would be reduced during the summer by up to a total of 1.8 million MWh under the worst-case summer period, which is 1.0 million MWh higher than under Alternative 1. The reduction in power generation under Alternative 2 represents a loss of up to 3.8 percent total generation in SPP during this summer period, 2.2 percent higher than under Alternative 1. Within the MISO RTO, power generation of all power plants during the summer months would be reduced at most by 3,401,385 MWh during the worst-case summer, accounting for 3.4 percent of total generation of the MISO RTO and 0.7 percent higher than Alternative 1. Table 18 presents the worst-case year reductions in power generation along with the relative percentage of these reductions as a percent of total generation for each RTO by season.

Further analysis of the impacts to power generation during the summers of 2002 and 2003 when simulated low summer flow events would occur indicate that high river temperatures tend to affect multiple plants simultaneously in the lower river in one or two periods within the summer season. During these periods, it is likely that wholesale electricity prices would increase, and potentially, with re-occurring low summer flow events under Alternative 2, there would be the potential for higher retail electricity prices in the long-term (SPP pers. comm. 2016). Re-occurring higher wholesale electricity prices would provide the rationale for state regulating agencies to increase consumer electricity rates higher than under Alternative 1. The impacts to retail electricity rates under Alternative 2 could be long-term, relatively small to large, and adverse and would be more adverse under Alternative 2 compared to Alternative 1, although the exact impact on energy prices (wholesale prices) and consumer electricity rates is uncertain. Higher electricity rates under Alternative 2 would result in adverse impacts to household and business spending because with higher electricity rates, households and business would have less money to spend on personal or business expenses, with resulting impacts to regional economic conditions.

Table 18. Worst-Case Year Reduction in Power Generation by RTO and Season under Alternative 2

Season	SPP	MISO
Reduction in Power Generation under the MRRMP-EIS Alternative (MWH)		
Winter	210,013	5,964
Spring	88,044	5,538
Summer	1,754,007	3,401,385
Fall	219,476	2,801,308
Percent of Power Generation Reduction as a Percent of the RTO's Generation		
Winter	0.5%	0.0%
Spring	0.1%	0.0%
Summer	3.8%	3.4%
Fall	0.3%	1.5%

Source: SPP 2015; SPP 2016; MISO 2014; MISO 2016

Coupled reductions in power generation from hydropower and thermal power plants during low summer flow events could lead to more adverse impacts to electricity rates because of simultaneous reductions in electricity generation during peak seasons. The re-occurrence of these conditions during low summer flow events would likely lead to higher wholesale electricity prices and 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.

4.4 Alternative 3 – Mechanical Construction Only

Under Alternative 3, power generation for most years and under the worst-case summer would be slightly more than under Alternative 1 in both RTOs (Table 19). There would be a negligible change in the impacts to consumer electricity rates and household spending and associated regional economic conditions compared to Alternative 1.

Table 19. Worst-Case Year Reduction in Power Generation by RTO and Season under Alternative 3

Season	SPP	MISO
Reduction in Power Generation under the MRRMP-EIS Alternative (MWH)		
Winter	210,013	5,964
Spring	81,174	11,076
Summer	658,386	2,664,205
Fall	208,800	2,799,888
Percent of Power Generation Reduction as a Percent of the RTO's Generation		
Winter	0.5%	0.0%
Spring	0.1%	0.0%
Summer	1.4%	2.6%
Fall	0.3%	1.5%

4.5 Alternative 4 – Spring ESH Creating Release

There would be slight benefits to power generation under Alternative 4 in the lower river and increased power reductions for plants in the upper river compared to Alternative 1. Over all locations, Alternative 4 would result in very slight benefits to power generation for plants. Within the SPP RTO, power generation would be slightly higher in the summer (0.2%) and slightly lower than in the fall compared to Alternative 1 under the worst case season. Impacts to power generation in the fall under Alternative 4 within the MISO RTO would be small relative to the total MISO power generation and would occur during non-peak periods (Table 20). There would be negligible change in power generation during the winter season. Because peak season summer power generation would have slight benefits under Alternative 4 and reductions in power generation in the off-peak fall period would be small in the RTOs, there would not be noticeable changes in wholesale electricity prices compared to Alternative 1. Similar to Alternative 1, the potential impacts to consumer electricity rates associated with higher wholesale electricity prices would be relatively long-term and adverse relative to current rates, although the exact impact on electricity prices (wholesale prices) and consumer electricity rates are uncertain. There would be a negligible change in the impacts to consumer electricity rates and household spending and associated regional economic conditions compared to Alternative 1.

Table 20. Worst-Case Year Reduction in Power Generation by RTO and Season under Alternative 4

Season	SPP	MISO
Reduction in Power Generation under the MRRMP-EIS Alternative (MWH)		
Winter	206,225	4,473
Spring	81,174	6,646
Summer	664,610	2,688,962
Fall	238,270	2,799,888
Percent of Power Generation Reduction as a Percent of the RTO's Generation		
Winter	0.5%	0.0%
Spring	0.1%	0.0%
Summer	1.4%	2.7%
Fall	0.3%	1.5%

Source: SPP 2015; SPP 2016; MISO 2014; MISO 2016

4.6 Alternative 5 – Fall ESH Creating Release

As described in Section 3.0, there would be slight benefits to power generation under Alternative 5 compared to Alternative 1. Impacts to power generation within the SPP and MISO RTOs would be very similar to those described under Alternative 1 (Table 21). Similar to Alternative 1, the potential impacts to consumer electricity rates associated with higher wholesale electricity prices would be relatively long-term and adverse relative to current rates, although the exact impact on electricity prices (wholesale prices) and consumer electricity rates are uncertain. There would be a negligible change in the impacts to consumer electricity rates and household spending and associated regional economic conditions compared to Alternative 1.

Table 21. Worst-Case Year Reduction in Power Generation by RTO and Season under Alternative 5

Season	SPP	MISO
Reduction in Power Generation under the MRRMP-EIS Alternative (MWH)		
Winter	210,013	2,982
Spring	81,174	11,076
Summer	664,610	2,688,962
Fall	208,800	2,799,888
Percent of Power Generation Reduction as a Percent of the RTO's Generation		
Winter	0.5%	0.0%
Spring	0.1%	0.0%
Summer	1.4%	2.7%
Fall	0.3%	1.5%

Source: SPP 2015; SPP 2016; MISO 2014; MISO 2016

4.7 Alternative 6 – Pallid Sturgeon Spawning Cue

There would be relatively small benefits to power generation under Alternative 6 compared to Alternative 1 (Table 22). Reductions in power generation under the worst-case summer would be slightly less than under Alternative 1 in both RTOs. Similar to Alternative 1, the potential impacts to consumer electricity rates associated with higher wholesale electricity prices would be relatively long-term and adverse relative to current rates, although the exact impact on electricity prices (wholesale prices) and consumer electricity rates are uncertain. There would be a negligible change in the impacts to consumer electricity rates and household spending and associated regional economic conditions compared to Alternative 1.

Table 22. Worst-Case Year Reduction in Power Generation by RTO and Season under Alternative 6

Season	SPP	MISO
Reduction in Power Generation under the MRRMP-EIS Alternative (MWH)		
Winter	210,013	5,964
Spring	81,174	6,646
Summer	663,170	2,688,962
Fall	234,415	2,801,308
Percent of Power Generation Reduction as a Percent of the RTO's Generation		
Winter	0.5%	0.0%
Spring	0.1%	0.0%
Summer	1.4%	2.7%
Fall	0.3%	1.5%

Source**:** SPP 2015; SPP 2016; MISO 2014; MISO 2016

5.0 Literature Cited

Hydropower Analysis Center. 2015. Personal Communication between Holly Bender, Pinyon Environmental and Mark Parrish and Margaret Ryan, hydropower specialists regarding energy and capacity values. Multiple conversations and email correspondence.

Midcontinent Independent System Operator (MISO). 2014. MISO 2013 Annual Market Assessment Report. Information Delivery and Market Analysis. June 2014. Available online at: https://www.misoenergy.org/Library/Repository/Report/Annual%20Market%20Report/2013%20Annual%20Market%20Assessment%20Report.pdf. Last Accessed: July 20th, 2016.

Midcontinent Independent System Operator (MISO). 2016. Market Reports. Files names: Historical Generation Fuel Mix by Region 2014 Report and Historical Generation Fuel Mix by Region 2013 Report. Available online at: https://www.misoenergy.org/LIBRARY/MARKETREPORTS/Pages/MarketReports.aspx. Last Accessed July 20th, 2016.

Office of Management and Budget. 2016. Table 10.1—Gross Domestic Product and Deflators Used in the Historical Tables: 1940–2021. Available online at: https://www.whitehouse.gov/omb/budget/Historicals. Last Accessed: 8/2/2016.

Southwest Power Pool (SPP). 2014. Generation Historical Mix. GenMix_2014.csv. Available online at: https://marketplace.spp.org/web/guest/generation-mix-historical. Last Accessed: August 11, 2016.

Southwest Power Pool (SPP). 2015. 2014 State of the Market. SPP Market Monitoring Unit. August 24th, 2015. Available online at: http://www.spp.org/documents/29399/2014%20state%20of%20the%20market%20report.pdf. Last Accessed: July 20th, 2016.

Southwest Power Pool (SPP). Personal Communication. 2016. Meeting with representatives from Southwest Power Pool to discuss RED and OSE impacts due to potential changes in the management of the Missouri River. June 16, 2016.

Southwest Power Pool (SPP). 2016. Generation Mix Historical Data. File Names: GenMix 2014.csv and GenMix 2015.csv. Available online at: https://marketplace.spp.org/web/guest/generation-mix-historical Last Accessed: July 20th, 2016.

USACE EM 1110-2-1701. USACE Engineering Manuals: Engineering and Design – Hydropower. Available online at: http://www.publications.usace.army.mil/Portals/76/Publications/EngineerManuals/EM_1110-2-1701.pdf?ver=2013-09-04-102303-087. Last Accessed: November 29, 2016.

USACE. 2011. Regional Economic Development Procedures Handbook. Institute for Water Resources. 2011-RPT-01. Available: http://www.iwr.Corps.army.mil/Portals/70/docs/iwrreports/2011-RPT-01.pdf.

USACE. 1985. Hydropower Engineer Manual 1110-2-1701. Section 6. 31 December 1985.

U.S. Energy Information Agency (EIA). 2016. Answers to Anticipated Questions for New EIA-923, “Power Plant Operations Report”. Available online at: https://www.eia.gov/electricity/2008forms/aaqs_923.html. Last Accessed: November 29, 2016.

Western Area Power Administration (WAPA). Personal Communication. 2016. Meeting between Chris Dixon (Louis Berger) and Steve Sanders (WAPA) to discuss RED and OSE impacts due to potential changes in the management of the Missouri River. June 2nd, 2016.