BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval to add 600 MW of renewable energy and 480 MW of energy storage capacity, among other items, as part of their joint 2022-2041 integrated resource plan, for the three year Action Plan period 2022-2024, and the Energy Supply Plan period 2022-2024.	Docket No. 21-06___

VOLUME 17 OF 18

TECHNICAL APPENDIX
TRANSMISSION PLAN AND ECONOMIC ANALYSIS

June 2021

Environmental Costs and Economic Impacts of Additional Resource Cases for 2021 Integrated Resource Plan

NV Energy

NERA
ECONOMIC CONSULTING

Prepared for:
NV Energy, Inc.

ECON-13

Project Team

David Harrison, Ph.D., Project Director
Andrew Busey
Paul-Angelo dell'Isola
Charles Kuchenbrod

This report reflects the research, opinions, and conclusions of its authors, and does not necessarily reflect those of NERA Economic Consulting or any of its clients.

NERA Economic Consulting
99 High Street, 16th Floor
Boston, Massachusetts 02110
Tel: +1 617 927 4500
Fax: +1 617 927 4501
www.nera.com

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I. Introduction and Background

This report is prepared for Nevada Power Company ("Nevada Power" or "NPC") and Sierra Pacific Power Company ("Sierra" or "SPPC") (together, the "Companies" or "NV Energy") to provide information on environmental costs and economic impacts for four plans (or "cases") for the 2021 Joint Integrated Resource Plan ("2021 IRP").

A. Overviews of Environmental Costs and Economic Impacts

This report provides estimates of the environmental costs and the economic impacts of the 2021 IRP cases over the 30-year period from 2022-2051.

1. Environmental Costs

The environmental cost estimates developed in this report are based on detailed information on air emissions, including emissions of conventional pollutants, toxic air pollutants, and carbon dioxide ("CO_2"). For emissions other than CO_2, we develop estimates of the environmental costs based upon estimates of power plant emissions and modeling that includes estimates of the detailed health costs from these emissions, including use of the most recent information from the U.S. Environmental Protection Agency ("EPA").

Environmental costs for CO_2 emissions are based on the methodology required by the August 2018 final rulemaking of the Public Service Commission of Nevada (the "Commission") in Docket No. 17-07020 (investigation and rulemaking to implement Senate Bill 65). This rulemaking calls for the social cost of carbon ("SCC") to be calculated by subtracting the costs related to carbon emissions that are internalized as private costs from the present value of the future global economic costs of CO_2 emissions as estimated by using the best available science and economics such as the analysis set forth in the "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis" released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016; we use the values for future global economic costs estimated by the Interagency Working Group on Social Cost of Greenhouse Gases ("Interagency Working Group") in its most recent February 2021 report (Interagency Working Group 2021).

The environmental cost assessments for the 2021 IRP cases also include estimates of the external costs of water consumption that are not included in the Present Worth of Revenue Requirement ("PWRR"). The environmental cost assessments also include qualitative evaluations of the potential environmental costs from other environmental effects (including land use, water quality and solid waste).

The results in this report are based upon a potential future national program to regulate carbon dioxide (CO_2) emissions from the electricity sector. We have modeled three potential regulatory scenarios using NERA's N_{ew}ERA model of energy and electricity markets: (a) Low CO_2 Price scenario; (b) Mid CO_2 Price scenario; and (c) High CO_2 Price scenario. The results in this report are based upon the Mid CO_2 Price scenario. The Mid CO_2 Price scenario presumes that a CO_2

allowance price trajectory is established through a national cap-and-trade program to implement regulation of carbon dioxide emissions from the electric utility sector. The CO_2 allowance prices are included in the PROMOD modeling done by NV Energy to determine the PWRR for the four cases. The PROMOD modeling includes the effects of the Mid CO_2 Price scenario on fuel prices for natural gas and coal, effects that are estimated using the N_{ew}ERA model. The allowance prices reflect the costs related to CO_2 emissions that are internalized as private costs in Nevada for purposes of calculating the SCC as mandated by the Commission. Using estimates of annual CO_2 emissions and the methodology outlined in the August 2018 Commission rulemaking for determining the SCC in each future year, we provide estimates of the social cost of carbon for the 2021 IRP cases. Note that the cap-and-trade program in the Mid CO_2 Price scenario is assumed to include initial allowance allocations provided to NV Energy (and other utilities), which lead to financial effects that are included in the PWRR for the purposes of financial planning.

2. Economic Impacts

The economic impact estimates in this report are measures of the effects of the 2021 IRP cases on the Nevada economy relative to a base case presumed to reflect circumstances embedded in the baseline of economic model we use. The economic impact estimates include both the positive effects of greater expenditures on the Nevada economy as well as the negative effects of greater revenue requirements (as reflected in increased electricity costs for residential, commercial and industrial customers). We use the model developed by Regional Economic Models, Inc. ("REMI") to estimate these economic impacts over the 30-year period from 2022 to 2051.

B. Background on Utility Resource Planning in Nevada

NV Energy and other Nevada electric utilities are required by Nevada regulations to file plans describing their options for supplying electricity to their service territories in the future. Nevada regulations require that the utilities consider environmental costs and economic impacts when evaluating potential plans. The Commission has laid out these regulations in the Nevada Administrative Code ("NAC"). This report provides estimates that comply with the regulations cited below.

1. Environmental Costs and the Present Worth of Societal Costs

The NAC requires Nevada electric utilities to rank their cases on the basis of the PWRR and Present Worth of Societal Costs ("PWSC"). The PWSC of a resource plan is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility" (NAC 704.937). Environmental costs are defined by the Commission as "costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan" (NAC 704.9359). The environmental costs "must be quantified for air emissions, water and land use" (NAC 704.9359).

2. Economic Benefits to Nevada Economy

Nevada regulations provide instructions to utilities on performing economic impact analyses of resource plans. NAC 704.9357 instructs utilities to conduct "an analysis of the changes that result in net economic benefits to Nevada from electricity-producing or electricity-saving resources." The regulations also specify that "the net economic benefit to the State must be quantified to reflect both the positive and negative changes and must include the net economic impact of renewable resources" (NAC 704.9357(1)).

C. Overviews of Resource Cases, Carbon Dioxide Price Scenarios, and Electricity System Modeling

This section provides overviews of the four 2021 IRP cases, the three CO_2 national policy scenarios that are developed and the one included in this report, and the NV Energy system-wide modeling that provides important inputs for our estimates.

1. Descriptions of IRP Cases

The 2021 IRP cases include four cases that reflect different combinations of resource and transmission additions. NV Energy's Preferred Plan is referred to as the Net-Zero case, reflecting added renewables to meet the state's goal of net-zero carbon dioxide emissions by 2050, i.e., for zero-carbon generation to equal electricity sales by 2050. The following are overviews of the 2021 IRP cases and lists of the resources and transmission additions common to all cases and those that differ among the cases.

a. Overview of the 2021 Cases

The 2021 IRP includes four cases for meeting electricity demand and state renewable energy requirements over the next 30 years (from 2022 to 2051).

The four IRP cases differ in terms of the amount of renewables to be installed. All four cases meet or exceed the renewable portfolio standard ("RPS") in all years, and all include near term capacity increases in the form of battery storage projects and combustion turbine upgrades. In one case ("Iron_Hot"), the North Valmy Station ("Valmy") coal-fired boilers are replaced with two new company-owned solar generating resources with co-located battery energy storage systems. In another case ("Repower Valmy"), the Companies propose to repower the Valmy coal-fired boilers to combust natural gas only. Two cases ("Net-Zero" and "Net-Zero with Geo") involve substantial renewables with the goal of achieving the state's 2050 net-zero carbon dioxide emissions goal. They both include the replacement of the Valmy coal-fired boilers with the new, company-owned solar and battery storage projects. The Net-Zero with Geo (herein referred to as "Geo") case includes additional geothermal resources.

b. Resources, Power Purchase Agreements and Transmission Expenditures Common to All Four IRP 2021 Cases

All four 2021 IRP cases include the following common resource additions, power purchase agreements and transmission expenditures.

Resources for Nevada Power common to all cases

- 360 MW of Firm Resource in 2034 and 900 MW of Firm Resource in 2040.
- Combined Cycle Turbine Upgrades in 2023.

Resources for Sierra common to all cases

- Purchase of the Fort Churchill Solar PV Facility in 2022.
- Combined Cycle Turbine Upgrades in 2022.
- 66 MW of battery storage capacity in 2023.

Power Purchase Agreements common to all cases

All four IRP cases include power purchase agreements (PPAs) with approximately 200 renewable projects of various generation types and capacities (including placeholders for future PPAs). All cases include the following PPAs.

- Approximately 429 MW of geothermal, 246 MW of hydro, 5 MW of municipal solid waste energy, 15 MW of landfill gas, 1,986 MW of solar PV, 100 MW of battery storage, 69 MW of solar thermal, and 152 MW of wind in the beginning of the analysis period (the start of 2022).
- 200 MW of additional solar PV with 75 MW of battery storage beginning in 2022.
- 500 MW of additional solar PV with 315 MW of battery storage beginning in 2023.
- 1,318 MW of additional solar PV with 862 MW of battery storage beginning in 2024.
- 7,281 to 10,773 MW of additional placeholder solar PV between 2027 and 2050.[1]
- 6,285 to 10,469 MW of additional placeholder battery storage between 2027 and 2050.

[1] These resources include those to ensure that each plan meets or exceeds compliance with Nevada's RPS throughout the 30-year planning period. The renewable requirements depend upon the amounts of renewable generation achieved through the relevant PPAs for each of the cases. Thus, the renewable forecasts differ by case.

Transmission upgrades common to all cases

The four IRP cases include various transmission network upgrades associated with integrating new solar PV PPAs into the electric distribution system. The following transmission line would require additional expenditures by NV Energy related to network upgrades.

- Greenlink North from Ft Churchill to Robinson Summit in 2031.

c. Resources, Power Purchase Agreements and New Transmission Projects Specific to Individual 2021 IRP Cases

The following are differences among the four IRP cases.

Resources for Nevada Power specific to individual cases

- Iron_Hot Case
  - 360 MW of Firm Resource capacity in 2037, 900 MW in 2039, and 360 MW in 2041.
- Repower Valmy Case
  - 1,260 MW of Firm Resource capacity in 2039 and 360 MW in 2042.
- Geo Case
  - 900 MW of Firm Resource capacity in 2042.
- Net-Zero Case
  - 900 MW of Firm Resource capacity in 2042.

Resources for Sierra specific to individual cases

- Iron_Hot Case
  - 336 MW of Firm Resource Capacity in 2034 and 336 MW in 2047.
- Repower Valmy Case
  - Repower Valmy from coal to natural gas in 2024.
  - 336 MW of Firm Resource Capacity in 2034 and 336 MW in 2047.
- Geo Case

  - 168 MW of Firm Resource Capacity in 2034.
- Net-Zero Case
  - 168 MW of Firm Resource capacity in 2034.

Power Purchase Agreements specific to individual cases, excluding placeholder PPAs

- Iron_Hot Case
  - Iron Point Solar PV (250 MW) with battery storage (200 MW) in 2024.
  - Hot Pot Solar PV (350 MW) with battery storage (280 MW) in 2025.
- Repower Valmy Case
  - No new PPAs.
- Geo Case
  - Iron Point Solar PV (250 MW) with battery storage (200 MW) in 2024.
  - Hot Pot Solar PV (350 MW) with battery storage (280 MW) in 2025.
- Net-Zero Case
  - Iron Point Solar PV (250 MW) with battery storage (200 MW) in 2024.
  - Hot Pot Solar PV (350 MW) with battery storage (280 MW) in 2025.

Transmission projects specific to individual cases

The cases include the following changes in the transmission network.

- Iron_Hot Case
  - Iron Point Interconnect in 2024.
  - Hot Pot Interconnect in 2025.
  - Harry Allen to Equestrian in 2042.
- Repower Valmy Case
  - Harry Allen to Equestrian in 2042.

- Geo Case
  - Iron Point Interconnect in 2024.
  - Hot Pot Interconnect in 2025.
  - Harry Allen to Equestrian in 2036.
  - Bighorn to Eldorado and Bighorn to McCullough in 2041.
- Net-Zero Case
  - Iron Point Interconnect in 2024.
  - Hot Pot Interconnect in 2025.
  - Harry Allen to Equestrian in 2036.
  - Bighorn to Eldorado and Bighorn to McCullough in 2041.

2. Overview of Carbon Dioxide Price Scenarios

There is considerable uncertainty regarding the potential future national regulation of CO_2 emissions from power plants and the extent to which future regulations might impose a "price" on CO_2 emissions. This section includes an overview of the recent history of regulations on CO_2 emissions from the electric utility sector, a summary of the three cap-and-trade scenarios we developed, and information on the specific scenario used in this report (Mid CO_2 Price scenario).

a. Recent History of Regulations on Electric Sector Carbon Dioxide Emissions

On October 23, 2015, the EPA published the final Clean Power Plan ("CPP") rule to regulate CO_2 emissions from existing fossil fuel-fired power plants under Section 111(d) of the Clean Air Act. The CPP would have taken effect in 2022 and included the possibility of a cap-and-trade program for state implementation of the CPP, based on the flexibility such implementation would give to minimize the costs of meeting emission reduction requirements. In response to litigation challenging EPA's promulgation of the CPP, on February 9, 2016, the Supreme Court "stayed" implementation of the CPP.

On March 28, 2017, President Donald Trump signed the Executive Order on Energy Independence (E.O. 13783), which (among other provisions) called for a review of the CPP. On October 16, 2017, EPA formally proposed to repeal the CPP after completing its review. On August 21, 2018, EPA proposed a new rule to reduce greenhouse gas emissions from power plants entitled the Affordable Clean Energy ("ACE") rule, to replace the CPP. The ACE Rule, which was finalized on July 8, 2019, provided guidelines for states to develop emission standards for existing electricity generation units, with no provision for state implementation via a cap-and-trade program for GHG emissions from power plants. In 2019, a number of groups filed lawsuits challenging the lawfulness of the ACE rule.

The Biden administration has indicated its intention not to defend the ACE Rule from litigation, and in January 2021, the U.S. Court of Appeals vacated the rule. The administration has not, however, yet announced any proposal to replace the ACE Rule with another program to implement Section 111(d) of the Clean Air Act for electric utility emissions. There are some indications, however, that the Biden administration would favor the flexibility of an emissions trading approach. As one indication, President Biden's American Jobs Plan, announced March 31, 2021 includes an Energy Efficiency and Clean Electricity Standard ("EECES") to achieve 100 percent clean power by 2035, including nuclear and hydropower as "clean" sources of electricity (WH 2021). Moreover, the House Energy and Commerce Committee Democrats recently introduced the CLEAN Future Act, which would establish similar emission reduction goals with a federal clean electricity standard ("CES") that would require retail sellers of electricity to ensure that 100 percent of their sales are from zero-emitting generation resources by 2035 (HR 2021). The proposal includes a provision providing for the flexibility to trade zero-emission credits before the final deadline; such flexibility could be included in any implementation of EECES (Clean Future Act). These developments thus suggest that a future regulation to reduce CO_2 emissions from the utility sector could include the cost-saving flexibility of a cap-and-trade approach.

b. Carbon Dioxide Price Scenarios and Scenario Used in This Report

In order to account for the range of possible future policies affecting electric sector CO_2 emissions, NERA developed several alternative CO_2 regulatory scenarios, one of which would involve federal regulation of greenhouse gas emissions from power plants that would not include a price on emissions ("No CO_2 Price" scenario) and three of which would involve implementation via national cap-and-trade programs for electric utility emissions of varying stringency that would lead to a price on emissions. The "Mid CO_2 Price" scenario presumes a national cap-and-trade program for electricity sector emissions is put in place with a cap trajectory consistent with allowance prices assumed to begin in 2025 at $20 per metric ton and increase each year at a five percent real rate. NERA also developed information for a "Low CO_2 Price" scenario and a "High CO_2 Price" scenario, for which the CO_2 price is assumed to begin in 2025 at $10 per metric ton and $35 per metric ton, respectively, and increase each year at the same assumed five percent real rate.

3. Electricity System Modeling Provided by NV Energy to Develop Inputs for Environmental and Economic Impact Estimates

For each resource case, NV Energy developed PROMOD modeling results to project how its units (including existing and new units) would be dispatched, how much market power would be purchased to meet the demand forecast for NV Energy customers, and how much capacity would be acquired to meet reliability requirements. The PROMOD modeling reflects demand on the part of NV Energy's "native load" customers and thus excludes demand from those who obtain power from other providers (but transmission from NV Energy).

The PROMOD results are based on the Mid CO_2 Price scenario, including the effects of the allowance price trajectory and the effects of that trajectory on fossil fuel prices. Because differences among the cases extend to the operation of existing units and to power purchases, the calculations of environmental costs and economic impacts relate to the entire set of resources used to meet demand for each case. Thus, the environmental cost and economic impacts estimates developed in this report account for the overall effects of each case, including effects of construction of new units and transmission projects, operation of all existing and new units, and purchased power and capacity.

Our calculations include environmental costs from emissions from all sources of power used to meet "native load" customer demand, including environmental costs from plants that generate power purchased by NV Energy outside Nevada. Our calculations of the external costs of water consumption reflect the use of company-owned water, since we assume that the costs of leased water at the Companies' plants and the costs of water consumption at other plants are included in the PWRR through operations costs and power purchase costs, respectively.

The economic impacts of the cases also are estimated for the system as a whole, taking account of differences among the cases in construction and operation costs as well as in revenue requirements. As noted, these analyses are based on the costs and revenue requirements related to NV Energy's "native load" customers and do not include expenditures and revenue requirements for entities that purchase generation from other sources and transmission capacity from NV Energy ("transmission-only customers"). Moreover, the economic impacts do not include the effects of purchases of power and capacity outside Nevada because the economic impacts would be outside Nevada.

D. Organization of This Report

The remainder of this report is organized as follows.

- Section II provides background related to air emissions environmental costs, including an overview of the national and state air quality standards that are relevant to Nevada, as well as a summary of the air emissions that are included in our report.

- Section III provides methodologies for estimating the environmental costs for emissions of conventional air pollutants and air toxics and the environmental cost results for these pollutants for the IRP cases.

- Section IV provides the methodologies for estimating the social cost of carbon and the social cost of carbon results for the IRP cases.

- Section V describes our methodology for assessing the external costs of water use (i.e., use that is not included in the PWRR) and provides estimates of these external costs for the IRP cases.

- Section VI describes our qualitative assessments of environmental costs related to land use effects, water quality effects and solid waste effects.

- Section VII describes our methodology for calculating economic impacts and provides estimates of the effects of the 2021 IRP cases on the Nevada economy.

- The appendices provide additional details on the data, methodologies, and results of the study.

II. Background on Air Quality and Air Emissions

This section provides background for our evaluations of the environmental costs of air emissions. The section includes an overview of air quality in Nevada and a list of the air emissions that are included in our study.

A. Background on Nevada Air Quality

We consider air quality for counties within Nevada in the context of the National Ambient Air Quality Standards ("NAAQS") for various criteria pollutants. Although compliance or non-compliance with the NAAQS does not affect the calculation of environmental costs (which depend on the damages related to emissions), this information provides a context for our environmental cost estimates.

1. National Ambient Air Quality Standards

The Clean Air Act of 1970 directs the EPA to set maximum permissible ambient (outdoor) concentrations for air pollutants considered harmful to public health and the environment. There are two types of NAAQS (EPA 2021a):

- *Primary standards* set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly; and
- *Secondary standards* set limits to protect public welfare, including protection against decreased visibility, and damages to animals, crops, vegetation, and buildings.

Currently, NAAQS exist for six "criteria" pollutants:

1. Carbon monoxide ("CO");
2. Lead;
3. Nitrogen dioxide ("NO_2");
4. Ozone, which forms primarily from oxides of nitrogen ("NO_x") emissions and volatile organic compound ("VOC") emissions. Carbon monoxide ("CO") and methane ("CH4") also react with NO_x to form ozone in the absence of more reactive organic compounds;
5. Particulate matter ("PM"), which forms primary PM emissions and precursor emissions, including sulfur dioxide ("SO_2") and NO_x; and
6. Sulfur dioxide ("SO_2").

Table 1 shows the NAAQS and the relevant averaging times for determining compliance for each of these pollutants. There are two particulate matter standards, one for PM_{10} ("coarse particles," which range in size from 2.5 to 10 micrometers ("µm") in diameter) and another for $PM_{2.5}$ ("fine particles," which are smaller than 2.5 µm in diameter). For the environmental cost assessments in this study, PM generally means $PM_{2.5}$ because $PM_{2.5}$ is the source of the health effects used to value ambient PM concentrations.

Table 1. National Ambient Air Quality Standards

Pollutant	Primary Standard	Averaging Times	Secondary Standard
Carbon Monoxide	9 ppm	8-hour (1)	None
	35 ppm	1-hour (1)	None
Lead	0.15 µg/m^3	Rolling 3-Month Average	Same as Primary
Nitrogen Dioxide	0.1 ppm	1-hour (2)	None
	0.053 ppm	Annual (Arithmetic Mean)	Same as Primary
Particulate Matter (PM_{10})	150 µg/m^3	24-hour (3)	Same as Primary
Particulate Matter ($PM_{2.5}$)	12 µg/m^3	Annual (Arithmetic Mean) (4)	15 µg/m^3
	35 µg/m^3	24-hour (2)	Same as Primary
Ozone	0.070 ppm	8-hour (5)	Same as Primary
Sulfur Dioxide	0.075 ppm	1-hour (6)	0.5 ppm, 3-hr averaging time (1)

Notes: Units of measure: ppm (parts per million) by volume; µg/m^3 (micrograms per cubic meter of air).
(1) Not to be exceeded more than once per year.
(2) 98th percentile, averaged over 3 years.
(3) Not to be exceeded more than once per year on average over three years.
(4) Annual mean, averaged over 3 years.
(5) Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years.
(6) 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years.

Source: EPA 2021a.

Areas where air pollution levels persistently exceed the NAAQS may be designated as "nonattainment" areas by EPA. In every state containing nonattainment areas, air pollution control authorities are charged with developing a State Implementation Plan ("SIP") aimed at bringing all counties into compliance with the NAAQS.

In Nevada, the Department of Conservation and Natural Resources, Division of Environmental Protection, Bureau of Air Quality Planning ("BAQP") is responsible for air quality surveillance in all areas of the state other than Clark (Las Vegas) and Washoe (Reno) counties. These two counties operate and maintain separate monitoring networks and publish their findings independently.

2. Compliance with NAAQS in Nevada

Table 2 summarizes the NAAQS attainment status for counties in Nevada. A nonattainment area is one that does "not meet (or that contributes to ambient air quality in a nearby area that does not meet) the national primary or secondary ambient air quality standard for the pollutant" (EPA 2021b). Only Clark County is in nonattainment for any of the criteria pollutants (EPA 2021c). An area previously classified as nonattainment, which seeks designation as attainment, is classified as a maintenance area and must submit a maintenance plan.

Table 2. Current Nonattainment and Maintenance Areas in Nevada

Pollutant	Averaging Times	Nonattainment Areas	Maintenance Areas
Carbon Monoxide	8-hour	None [1]	Clark County, Carson City, Douglas County, Washoe County
	1-hour	None	None
Lead	Rolling 3-Month Average	None	None
Nitrogen Dioxide	1-hour	None [2]	None
	Annual (Arithmetic Mean)	None [2]	None
Particulate Matter (PM_{10})	24-hour	None	Clark County, Washoe County
Particulate Matter ($PM_{2.5}$)	Annual (Arithmetic Mean)	None	None
	24-hour	None	None
Ozone	8-hour	Clark County	None
Sulfur Dioxide	1-hour	None	None

Notes: (1) In September 2010, all carbon monoxide areas were re-designated as maintenance areas.
(2) In September 1998, the only Nitrogen Dioxide nonattainment area was re-designated to maintenance.
Source: EPA 2021c.

3. Nevada Air Quality Standards

Although Nevada statewide air quality standards (which govern the entire state other than Clark and Washoe counties) are generally based upon the national standards, there are a few exceptions (BAQP 2003). The eight-hour state standard for carbon monoxide is reduced to 6.0 ppm (from 9.0 ppm in the NAAQS) at altitudes equal to or greater than 5,000 feet in Nevada because of the decrease in available oxygen at higher altitudes. Currently, the Lake Tahoe monitoring sites are subject to this stricter standard. Also, the one-hour ozone standard in Nevada is 0.12 ppm (similar to the previous national one-hour standard that was revoked in 2005) with the exception of the Lake Tahoe Basin, where the standard is 0.10 ppm.

4. Trends in Nevada Air Quality

The most recent Trends Report published by the BAQP covers the 11-year period from 2000 to 2010 (BAQP 2013). BAQP also releases some monitoring data in near real-time on their website. BAQP actively monitors the current and projected concentrations of ambient air pollutants with monitors located in the following towns: Carson City, Gardnerville, Fernley, Fallon, Elko, and Pahrump.

Ambient concentrations of CO have decreased during the report period, remaining well below the current NAAQS. The highest concentrations of CO occur during the winter months, when temperature inversions trap CO near ground level.

Ambient concentrations of ozone have consistently remained below the 2008 NAAQS during the report period. The concentrations are affected by the quantity of NO_x and VOC, temperature, and the amount of sunlight.

The highest concentrations of $PM_{2.5}$ have been reported during the winter months, when wood combustion is at its peak and temperature inversions occur, trapping $PM_{2.5}$ near ground level. Ambient concentrations of $PM_{2.5}$ have increased in Carson City and Gardnerville, approaching the NAAQS. In Fernley, ambient concentrations of $PM_{2.5}$ have decreased.

Several exceedances of the 24-hour standard for PM_{10} have been reported in Pahrump, although the exceedances have been reduced and have generally occurred during uncontrollable high wind events. Throughout the rest of Nevada, ambient concentrations of PM_{10} have declined and have remained well below the NAAQS.

B. Air Emissions Included in This Study

Table 3 summarizes the air emissions considered in this study. The table shows the relevant NAAQS or relevant air toxic category for each type of air emission and the method we use to calculate environmental costs. As noted, for some emissions there is not sufficient information to develop environmental cost estimates.

Table 3. Summary of Methods to Value Air Emissions

Pollutant	Relevant NAAQS	Valuation method
CO_2	None	Social Cost of Carbon [1]
NO_x	PM, Ozone, NO_2	Site-specifc damage functions for PM and Ozone
PM	PM	Site-specific damage function for PM
VOC	Ozone	No contribution to ambient ozone concentration in Nevada based on 1993 air quality study
CO	CO	Not monetized due to highly site-specific damages and limited available information
SO_2	SO_2, PM	Site-specifc damage functions for SO_2 [2] and PM
Mercury	None	Uniform damage value imputed from U.S. EPA MATS RIA [3]
HCl	None	Not monetized following U.S. EPA MATS RIA [4]

Notes: [1] We develop estimates of the social cost of carbon based upon the methodology and data sources required in the August 2018 final Commission regulations to implement Senate Bill 65.

[2] Although SO_2 emissions from power plants are subject to a national cap-and-trade program (Acid Rain Trading Program, established in the 1990 Amendments to the Clean Air Act), the program is not expected to be binding in the future (and thus lead to positive allowance prices), as evidenced by recent allowance auction results (EPA 2020a).

[3] EPA has issued a recent proposal to modify hazardous air pollutant standards (HAPS) identified in the final MATS Rule (EPA 2020b). The methodology for quantifying the direct benefits from mercury in the proposed rule relies on the 2011 MATS RIA (EPA 2011b, Table 4-6, pp. 55-56).

[4] The proposed modification of the MATS Rule (EPA 2020b) limits HCl emissions. The methodology for quantifying benefits relies on the 2011 MATS RIA, which does not provide damage values for HCl (EPA 2011b, pp. 4-1).

For NO_x, VOC, PM, and SO_2 emissions in Nevada, we develop estimated damage-based values that reflect the potential adverse health effects. Environmental costs for CO emissions cannot be calculated because the lack of air quality modeling data. We have, however, estimated levels of CO emissions under the respective cases. Similarly, we include estimated hydrogen chloride ("HCl") emissions in this analysis but do not monetize HCl damages because of the absence of EPA dollar value estimates, as explained in Section III. We do not consider effects of NO_x emissions on NO_2 concentrations because EPA does not quantify potential health effects for NO_2 (EPA 2005a). We do not consider lead emissions because electric generating units are not substantial emitters of lead (EPA 2011b, p. 73). We do not expect that including costs for other pollutants, if they could be estimated, would have any significant effect on our estimates of the environmental costs of conventional and toxic air emissions.

III. Environmental Costs for Conventional Air Emissions and Air Toxics

This section describes our methodologies for assessing the environmental costs of conventional air emissions and air toxic emissions for the 2021 IRP cases.

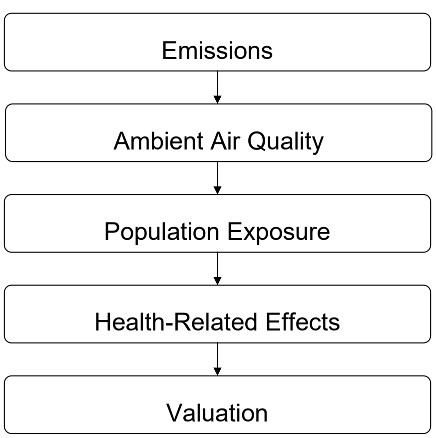
A. Methodology for Estimating Environmental Costs

Conventional air emissions affect local air quality and relate to programs to achieve the various NAAQS. The conventional air emissions included in this study are NO_x, PM, VOC, CO, and SO_2. We use a damage value approach to develop estimates of the environmental costs in Nevada of conventional air emissions. The damage value approach begins with the premise that the conceptually correct measure of the value of a ton of pollutant is equal to the value of the damages that that ton causes (assuming no binding cap-and-trade program or other price for emissions). Damages can include effects on health, visibility, and agriculture, although our estimates focus on health effects, the most significant category. The empirical information used in this approach includes information developed by EPA for purposes of its regulatory impact analyses for individual regulations based upon its summaries of research by environmental scientists and economists (although NERA has not verified this information).

1. Overview of Damage-Function Approach

The damage-function approach for health effects is illustrated in Figure 1. The steps in estimating the dollar value of damages from these emissions are summarized below.

Figure 1. Steps in Damage-Function Approach to Estimate Environmental Costs from Conventional Air Emissions



Source: Adapted from EPA 2011a.

2. Effects of Emissions Changes on Changes in Ambient Air Quality

The conventional air emissions included and monetized in this study contribute to ambient concentrations of PM, ozone, and SO_2. Ambient PM concentrations arise from PM particles that are emitted directly and also from small-diameter particulates that are formed by chemical reactions in the air involving NO_x and SO_2. Ozone is formed by complicated atmospheric photochemical reactions potentially involving NO_x, VOC, and sunlight. Ambient SO_2 concentrations arise from SO_2 emissions. Because the health effects that provide estimated damage values depend on ambient concentrations of these particles, not on direct emissions, the damage-function approach requires that direct air emissions be translated into ambient effects.

3. Effects of Ambient Air Quality Changes and Population on Exposure

The damages associated with increases in ambient concentrations of PM, ozone, and SO_2 depends on the number of people exposed to the increased concentrations. Increases in PM, ozone, and SO_2 concentrations will have larger health effects in an urban area than in a rural area.

4. Effects of Population Exposure on Health Effects

The relationship between increased exposure and increased health effects is a crucial element of the damage-function approach to assessing environmental costs. For health effects, such relationships typically are measured with concentration-response ("C-R") functions, which are based upon statistical studies from the epidemiology literature.[2] "C-R functions are equations that relate the change in the number of individuals in a population exhibiting a 'response' … to a change in pollutant concentration experienced by that population" (EPA 1999, p. 52). The "responses" described by C-R functions are often referred to as health endpoints.

C-R functions translate changes in the numbers of people exposed to various ambient pollutant concentrations into changes in health effects. Accurate application of these functions depends on consistency in the information on baseline incidence and relevant population. Specifically, the exposed population and baseline incidence rates used in calculating health effects must be consistent with the sample population used to estimate the relevant C-R function. If, for instance, a study only considers adults age 30 and over in estimating a C-R function, populations and baseline incidences for children should not be included in any use of that C-R function to estimate health effects from changes in ambient air quality.

EPA notes that "epidemiological studies, by design, are unable to definitively prove a causal relationship between an exposure and a given health effect; they can only identify associations or correlations between exposure and the health outcome" (EPA 1999, p. D-7). Nonetheless, such studies generally provide the primary bases for developing C-R functions.

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2 In the case of non-health effects (such as effects on agricultural yield), these relationships are typically called "exposure-response" functions.

5. Valuation of Health Changes

Once increased incidences of health effects are estimated, the dollar values of those effects must be estimated to generate estimated damage values for air emissions. Over the past several decades, economists and other researchers have devised various methods for estimating how much people are willing to pay to reduce risks to health or premature mortality. Some of the methods rely upon the implicit tradeoffs that individuals make in various decisions; for example, statistical models have been used to estimate the increased wages that workers demand in riskier occupations in order to calculate the value of a statistical life. Other methods rely upon direct surveys of representative individuals, the results of which may be analyzed to produce demand curves for reduced health or mortality risk.

B. Environmental Costs of Conventional Air Emissions

Our estimated damage values related to PM, ozone, and SO_2 effects are based on emissions and air quality levels developed specifically for the facilities in this study, supplemented with estimates of concentration-response functions and health effect valuations developed by EPA in its regulatory impact assessments for relevant air emissions and air quality rules. As noted in Appendix F, these estimates use the most recent available EPA information on these relationships (although we have not developed independent assessments of the validity of these functions and valuations).

1. Estimates of Emissions

NV Energy has performed dispatch modeling using PROMOD for each of the four 2021 IRP cases, appropriately including allowance prices for CO_2 emissions after 2025, when the national CO_2 cap-and-trade program is assumed to begin. The modeling output includes estimates of the annual heat input (in MMBtu) for each generating unit (both existing units and potential new units) in the Nevada Power and Sierra systems for each case from 2022 through 2051. NV Energy also has developed estimated emission rates for most of the units, and emission rates for the remaining units were obtained from EPA's Emissions and Generation Resource Integrated Database ("eGRID"). NV Energy has also provided information on the source regions of purchased power from the market that allows us to estimate relevant emission rates for these purchases as well. We calculate the average emissions factors for the relevant regions based on the results of the NewERA model so that the emissions factors are consistent with the carbon price scenario assumed for this analysis. We take a weighted average of those regional emissions factors to obtain an effective emissions rate for energy NV Energy purchases from the market.

With these sets of information, we forecast total emissions of each pollutant in each year under each case. Appendix D to this report provides these forecasts, as well as additional details on the data sources and methodologies used to develop them.

2. Estimates of Air Quality Effects

In any particular case, the relationship between emissions and air quality depends on a number of factors, including generating unit characteristics, geographic location, and meteorology. To develop likely air quality impacts associated with emissions from the four alternative cases, we rely on previous air quality results developed for Nevada Power (Harrison et al. 1993a) and Sierra (Harrison et al. 1993b). Appendix E provides details on these air quality modeling results, and Appendix F provides details on how we have applied them in this study.

3. Estimates of Health Effects

Application of the damage-function approach requires identifying the appropriate health and welfare endpoints potentially affected by changes in ambient PM and ozone concentrations and developing valuations for effects on these endpoints. The EPA analyses that we relied on for this study include estimates of the health effects of changes in ambient $PM_{2.5}$ and ozone concentrations as well as in concentrations of SO_2. The majority of damages come from changes in premature mortality rather than in changes in various forms of morbidity.

Table 4 lists the kinds of health effects quantified in the EPA analyses. We use these health effects and the C-R functions identified and employed in recent EPA analyses in our assessment of environmental costs. Appendix F to this report provides detailed information on the specific C-R functions and valuation estimates applied to these health endpoints. Note that we have not developed independent assessments of the validity of EPA estimates.

Table 4. Health Effects Related to Conventional Air Emissions Quantified in EPA Analyses and Used in this Study

Air Emissions	Health Effects
Particulate matter	Premature mortality based on cohort study estimates
	Infant mortality
	Acute Myocardial Infarction, Nonfatal
	Strokes
	Out-of-hospital Cardiac Arrest
	Hospital admissions for respiratory causes
	Hospital admissions for Cerebro- and Peripheral Vascular Diseases
	Emergency room visits for respiratory causes
	Emergency room visits for cardiovascular causes
	Hay Fever/Rhinitis
	Asthma Symptoms
	Incidences of Asthma
	Work loss days
	Minor restricted-activity days
	Lung Cancer
	Parkinson's Disease
	Alzheimer's Disease
Ozone	Premature mortality based on short-term study estimates
	Hospital admissions for respiratory causes
	Emergency room visits for respiratory causes
	Asthma Symptoms
	Incidence of Asthma
	Minor restricted-activity days
	School absence days
Sulfur dioxide	Respiratory hospital admissions
	Emergency room visits for asthma
	Asthma exacerbation
	Acute respiratory symptoms

Sources: EPA 2010, 2021d.

4. Estimates of the Valuation of Health Effects

The EPA regulatory analyses also provide a framework for estimating the monetized value of appropriate health and welfare endpoints for assessment of environmental costs in Nevada. In this study, we rely on the estimates that have been developed by EPA and apply these estimates where feasible.

5. Environmental Costs of Conventional Air Emissions

Table 5 summarizes our estimates of the present value of environmental costs associated with the conventional air emissions examined in this study for the four 2021 IRP cases. These costs are calculated as present values as of 2022 in 2022 dollars using nominal discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra, appropriately translated into real discount rates. Environmental costs for conventional air emissions by facility type are shown in Appendix G.

Table 5. Present Values of Environmental Costs for Conventional Air Emissions (2022$ Millions)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
NOx	$0.92	$1.02	$1.04	$0.91
PM	$27.61	$29.69	$28.78	$27.55
VOC	$0.00	$0.00	$0.00	$0.00
CO	--	--	--	--
SO2	$1.37	$1.44	$1.41	$1.37
Total	**$29.90**	**$32.14**	**$31.23**	**$29.83**

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy, before the present value was calculated using the nominal annual discount rates.
Total may differ from the sum of the rows due to independent rounding.
"--" denotes that the environmental costs of the air emission are not monetized.

Source: NERA calculations as explained in text.

C. Environmental Costs of Air Toxics

The estimated damage values for air toxics emissions relate to mercury and HCl emissions.

1. Estimates of Mercury Emissions

Estimating damages is somewhat different for mercury than for the other emissions because mercury in the air is not directly associated with adverse effects. Mercury is only associated with potential harmful effects when it is deposited on the ground or in water bodies, from which it can enter the food chain and be consumed by humans. The main mechanism by which emitted mercury causes health effects thus is through ingestion of fish rather than inhalation.

A significant share of mercury emissions becomes elemental mercury and travels long distances in the atmosphere before deposition. Since the linkages between mercury emissions and mercury depositions are not well known, it is not possible to calculate damages per plant based on an affected population. We therefore use an average damage value for mercury emissions from U.S. power plants, as described below.

2. Methodology for Estimating Environmental Costs for Mercury Emissions

Taking these limitations into consideration, EPA developed an alternative methodology for monetizing the damages associated with mercury emissions as described in the 2011 MATS RIA, the most recent analysis.[3] Specifically, since the primary channel through which mercury affects human health is the consumption of fish, EPA uses fish tissue samples and data on angler population to estimate the mercury exposure of individuals who consume self-caught freshwater fish throughout the country. EPA's valuation methodology is based on a link between prenatal exposure to mercury and cognitive impairment in children. EPA uses estimates of exposure and this linkage to estimate the resulting IQ loss suffered by children exposed to mercury in utero. EPA then monetizes these IQ losses by calculating how such losses affect discounted lifetime earnings. As noted, we have not evaluated the scientific and economic analyses underlying EPA's damage values.

3. Damage Value for Mercury Emissions

As noted, mercury damages cannot be accurately traced to individual sources (or even foreign vs. domestic sources); therefore, we use a uniform per-ounce damage value for mercury emissions. We take as our source EPA's regulatory impact analysis ("RIA") for MATS (EPA 2011b). In this RIA, EPA publishes national aggregate estimates of the benefits of reducing mercury emissions under a number of scenarios. Based on these estimates, we calculate a dollar value per ounce of mercury exposure for each of EPA's published scenarios and use the median value as our estimate.

EPA reports that its methodology does not include some potential damages due to mercury emissions, as discussed in Appendix F. Our methodology is conservative, however, in that it would tend to overstate the damages due to mercury emissions in at least two ways:

1. EPA evaluated several discount rates for discounting changes in future earnings (lower rates have higher benefits); we used the lowest discount rate.

2. We based our damage value on national aggregate numbers, but freshwater fishing rates in Nevada are significantly lower than the national average (EPA 2011b).

4. Environmental Costs from Mercury Emissions

Table 6 summarizes our estimates of the present value of environmental costs associated with the air toxics examined in this study for the four 2021 IRP cases. These costs are calculated as present

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[3] On February 7, 2019, EPA proposed a revision of the National Emissions Standards for Hazardous Air Pollutants (HAPs) (EPA 40 CFR Part 63). The benefits analysis supporting the proposed revised rulemaking distinguishes direct HAPs benefits quantified based on mercury reductions from co-benefits (i.e., benefits from other emissions reduced as a result of controls to meet MATS requirements) (EPA 2020b). The benefits assessment included for mercury in the proposed rulemaking (EPA 2020b) relies upon the same methodology and results used in the 2011 RIA filing for the Final MATS Rule (EPA 2011b, Chapter 4).

values as of 2022 in 2022 dollars using nominal discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra, appropriately translated into real discount rates. Environmental costs for conventional air emissions by facility type are shown in Appendix G

Table 6. Present Values of Environmental Costs for Air Toxics (2022$ Thousands)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
Mercury	$0.34	$0.34	$0.33	$0.34
HCl	--	--	--	--
Total	**$0.34**	**$0.34**	**$0.33**	**$0.34**

Notes: All values are present values as of 2022 in thousands of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy, before the present value was calculated using the nominal annual discount rates.
Total may differ from the sum of the rows due to independent rounding.
"--" denotes that the environmental costs of the air emission are not monetized.

Source: NERA calculations as explained in text.

D. Total Environmental Costs for Conventional Air Emissions and Air Toxics

This section combines estimates of environmental costs for conventional air emissions and air toxics. We show the environmental costs for each of the IRP cases as well as the differences in environmental costs relative to the preferred case. We also discuss uncertainties and the implications of omitted environmental costs related to the air emissions.

1. Environmental Costs of Air Emissions for 2021 IRP Cases

Table 7 summarizes our estimates of the present value of environmental costs associated with the conventional air emissions and air toxics examined in this study for the four 2021 IRP cases. These costs are calculated as present values as of 2022 in 2022 dollars using nominal discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra, appropriately translated into real discount rates. Environmental costs for conventional and toxic air emissions by facility type are shown in Appendix G.

Table 7. Present Values of Environmental Costs for Conventional Air Emissions and Air Toxics (2022$ Millions)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
NOx	$0.92	$1.02	$1.04	$0.91
PM	$27.61	$29.69	$28.78	$27.55
VOC	$0.00	$0.00	$0.00	$0.00
CO	--	--	--	--
SO2	$1.37	$1.44	$1.41	$1.37
Mercury	$0.00	$0.00	$0.00	$0.00
HCl	--	--	--	--
Total	**$29.90**	**$32.14**	**$31.23**	**$29.83**

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy, before the present value was calculated using the nominal annual discount rates.
Total may differ from the sum of the rows due to independent rounding.
"--" denotes that the environmental costs of the air emission are not monetized.

Source: NERA calculations as explained in text.

2. Environmental Costs of Air Emissions Relative to the Preferred Plan

Table 8 summarizes the differences in our estimates of the present value of environmental costs of conventional and toxic air emissions relative to the Net-Zero case, the Preferred Plan. The Net-Zero case and the Geo case have lower conventional and toxic air emissions costs than the Iron_Hot Case and the Repower Valmy case, with the Geo case having the smallest costs and the Iron_Hot case having the largest costs.

Table 8. Differences in Present Values of Environmental Costs of Conventional Air Emissions and Air Toxics, Relative to Net-Zero Case, 2022-2051 (2022$ Millions)

Net-Zero	Iron_Hot	Repower Valmy	Geo
-	$2.24	$1.33	-$0.07

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy, before the present value was calculated using the nominal annual discount rates.

Source: NERA calculations as explained in text.

3. Implications of Omitted Health and Welfare Effects

These monetary estimates do not include certain health and welfare effects that may be associated with these pollutants, but for which EPA concluded the available data were insufficient to quantify effects. As noted in Appendix F, we have reviewed these effects and conclude that they are likely to be small relative to the quantified costs, and hence their exclusion is not likely to have a material impact on these environmental costs and the comparisons of these environmental costs among the cases.

IV. Environmental Costs for Carbon Dioxide Emissions

This section provides information on the methodology required in the Commission's August 2018 final regulation to implement Senate Bill 65, which requires estimation of the Social Cost of Carbon. We provide the inputs to this estimation and our estimates of the social costs of carbon for the IRP cases based upon that methodology.

A. Methodology Specified by the Commission for Calculating the Social Costs of Carbon

The Commission's August 2018 final regulation to implement Senate Bill 65 includes the following requirements related to evaluation of the social costs of carbon for the purposes of the utility's supply plan evaluation.

> For the purposes of subsection 4 and NAC 704.9215 and 704.9359, the social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics such as the analysis set forth in the 'Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis' released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016.[4]

To implement this requirement for years in which there would not be a cap-and-trade program (2022-2024), we estimate the social costs of carbon for CO_2 emissions by applying damage values equal to the most recent values developed by the Interagency Working Group in 2021.[5] For years in which there would be a binding cap-and-trade program (2025-2051), we estimate the social costs of carbon for CO_2 emissions by calculating the difference between these recent damage values developed by the Interagency Working Group and the cap-and-trade allowance prices, which reflect the costs internalized as private costs.[6]

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4 Amendments to NAC 704.937, as identified in LCB File No. R060-18 (Section 3, subheading 5).

5 There is some confusion in terminology, since the damage-based values developed by the Interagency Working Group are referred to as estimates of the "social cost of carbon," the same term used by the Commission to define their calculation. To avoid confusion, in this report we refer to the Commission calculation as the social cost of carbon and refer to the estimates developed by the Interagency Working Group as the global economic costs of carbon emissions or as damage values.

6 Note that under a binding national cap-and-trade program, total emissions are capped and thus an increase in a ton of CO_2 emissions in Nevada would not result in additional environmental damages. As a result, when a biding cap-

B. Inputs for Social Costs of Carbon Based on Commission Requirements

Consistent with the Commission requirements, we develop annual social costs of carbon values that are based on (a) the most recent global economic cost values developed by the Interagency Working Group (2021)[7] and (b) the CO_2 allowance prices in the Mid CO_2 Price scenario, which reflect the costs that are internalized as private costs to NV Energy.

1. Interagency Working Group Global Economic Cost Values

The Interagency Working Group in 2021 provided updated estimates of future global economic costs from an additional ton of carbon dioxide for three discount rates—2.5 percent, 3 percent, and 5 percent—using the average of the damages distribution it calculated from modeling results. It also provided a fourth set of global economic costs based on the 3 percent discount rate and the 95th percentile of the damages distribution, which it noted are designed "to represent the higher-than-expected impacts from temperature change further out in the tails of the [global economic cost] distribution" (Interagency Working Group 2021, p. 10).

These four sets of values cover a very large range and, indeed, the full range of values reported by the Interagency Working Group was much greater than these four sets of estimates. The estimates in this report are the values developed by the Interagency Working Group for a 3 percent discount rate.

Appendix H provides information on the methodology used by the Interagency Working Group to develop these estimates. Table H-1 in Appendix H summarizes the trajectory of annual global economic cost values reported by the Interagency Working Group for the mean of the distribution for three discount rates as well as the 95th percentile value of potential damages for the 3 percent discount rate.

2. Adjusting for Costs of CO_2 Emissions Internalized as Private Costs

We develop estimates of the social costs related to CO_2 emissions for the years before the cap-and-trade program is introduced in the Mid CO_2 Price scenario (2022-2024) by multiplying the

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and-trade program is in place, additional emissions do not lead to additional environmental damages and thus it would be appropriate be use a value of zero for the additional environmental damages. This assessment of the implications of a cap-and-trade program is not consistent with the approach required by the Commission in the August 2018 final rule, and thus we do not incorporate this feature of a national cap-and-trade program in our analyses in this report.

7 The February 2021 Interagency Working Group interim results updates the 2016 results for inflation. A full evaluation is expected to be completed by the Interagency Working Group by January 2022 (see Interagency Working Group 2021, p. 1).

estimated CO_2 emissions by the Interagency Working Group damage value as included in Table H-1.

For each year in which there would be a binding cap-and-trade program under the Mid CO_2 price scenario, as noted, the Commission methodology requires that the cost of CO_2 emissions be estimated by subtracting the costs associated with CO_2 emissions internalized as private costs from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. Thus, for years in which we presume there would be a binding cap-and-trade program (2025-2051), we develop estimates of the social costs of CO_2 emission by multiplying the estimated CO_2 emissions by the difference between the Interagency Working Group value for that year (i.e., the net present value of future global economic costs resulting from an additional ton of CO_2 emissions) and the CO_2 allowance price for that year (i.e., the costs of CO_2 internalized as private costs).

Table H-2 in Appendix H provides information on the annual allowance prices used for the Mid CO_2 price scenario.[8] Table H-3 shows the Interagency Working Group values minus the allowance price values. Consistent with the requirements identified in the regulations to implement Senate Bill 65, we use the values in Table H-4 to develop estimates of the social costs of CO_2 emissions.

C. Social Costs of Carbon

This section provides estimates of the social costs of carbon for the IRP cases as well as differences relative to the Preferred Plan.

1. Social Costs of Carbon for 2021 IRP Cases

The social costs of carbon emissions for the four 2021 IRP cases are calculated by multiplying the annual social cost of carbon values in Table H-3 by estimates of annual CO_2 emissions. Table 9 shows the social cost of carbon estimates (as present values) based on the Mid CO_2 Price scenario using the 3 percent discount rate and average damage values. Appendix H provides values for alternative discount rates and damage value assumptions for the social costs of carbon.

[8] The Mid CO_2 price scenario assumes a binding cap-and-trade program would begin in 2025. Thus, allowance price values are assumed to be zero for years through 2024. Appendix B provides additional information on the assumptions and modeling underlying the Mid CO_2 price scenario.

Table 9. Present Values of the Social Costs of Carbon, 2022-2051 (2022$ Millions)

Net-Zero	Iron_Hot	Repower Valmy	Geo
$5,569	$6,140	$6,123	$5,553

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 based on values reported by Interagency Working Group (2021) and the allowance price projections for the Mid CO_2 Price scenario. The values reflect a 3 percent discount rate.

Source: NERA calculations as explained in text.

2. Social Cost of Carbon Relative to Preferred Plan

Table 10 shows the differences between the social costs of carbon estimates for the other three cases relative to the Net-Zero case (Preferred Plan). The social costs of carbon are substantially lower for the Net-Zero case and the Geo case than for the Iron_Hot case and the Repower Valmy case.

Table 10. Differences in Present Values of Social Costs of Carbon, Relative to the Net-Zero Case (2022$ Millions)

Net-Zero	Iron_Hot	Repower Valmy	Geo
-	$571	$554	-$16

Note: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 based on values reported by Interagency Working Group (2021) and the allowance price projections for the Mid CO_2 Price scenario. The values reflect a 3 percent discount rate. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

3. Uncertainties Related to Estimates of the Social Cost of Carbon

NERA has, in reports for prior NV Energy IRPs, noted that the global values developed by the Interagency Working Group are not comparable to the environmental costs calculated for air and toxic emissions for several reasons: (a) the Interagency Working Group values are more uncertain partly because they are based upon impacts in the distant future; (b) the Interagency Working Group values are based on different discount rates than the private (NV Energy) discount rates used to calculate the present value of the other environmental costs; and (c) the Interagency Working Group values are based upon global damages rather than U.S. or Nevada-specific damages.

V. External Costs of Water Consumption

This chapter provides a background on water use by NV Energy's generating plants and describes our methodology for estimating the potential additional external costs of water consumption by Nevada Power and Sierra based upon the value of water use that is not included in the PWRR. These additional costs relate to water from wells owned by NV Energy and represent the opportunity cost value of the water, i.e., the value of the next best alternative use of the well water (e.g., leasing or selling it on the market) if NV Energy did not have to use the water to cover its own consumption requirements.

No additional water costs are calculated for power purchased by NV Energy through contracts or spot market transactions because we assume that all water costs are included in the prices that NV Energy pays and thus are already accounted for in the PWRR. Similarly, no additional water costs are calculated for any of the renewable power purchase agreements because we assume that the costs of any water that is used by renewable developers—whether these are actual costs to the developers or opportunity costs of using their own water supply—will be included in the price paid by NV Energy and thus in the PWRR.

A. Water Use Background

1. Water Rights in Nevada

Water rights in Nevada are considered real property and can be bought, sold, traded, and leased (Nevada DWR 1999, p. 2-2). Applications for new water rights are submitted to the State Engineer for approval. The place of use or the type of use of a water right can also be changed with approval from the State Engineer (Nevada DWR 1999, pp. 2-1 to 2-2).

As noted in Nevada's State Water Plan, the attributes of appropriative water rights are as follows:

1. "beneficial use is the measure and limit of the right to the use of the water;
2. rights are stated in terms of definite quantity, manner of use, and period of use; and
3. a water right can possibly be lost by abandonment or forfeiture" (Nevada DWR 1999, p. 2-2).

Water right holders do not take ownership in the physical water being diverted from the water body; rather, the State grants a right to use the water in a beneficial manner. This is codified in the following Nevada Revised Statues ("NRS"):

- "[A]ll sources of water supply within the boundaries of the State whether above or beneath the surface of the ground, belong to the public" (NRS § 533.025); and

- "Beneficial use shall be the basis, the measure and the limit of the right to the use of water" (NRS § 533.035).

Examples of beneficial use include, but are not limited to, domestic, agricultural, industrial, and recreational.[9]

The other fundamental concept governing water rights is that of prior appropriation or "First in Time, First in Right." Beyond historically creating a system in which the right to water was acquired by diverting water and applying it to a beneficial use, this doctrine ensures that a right which is acquired earlier in time has priority to a similar right that is acquired at a later time. This implies that during periods of water shortages (e.g., droughts), the more senior priority right holders are given their share before the more junior priority right holders receive their water (NV DWR 1999, p. 8-1).

2. Beneficial Uses of NV Energy's Water Rights

As mentioned above, industrial uses are considered beneficial under Nevada State water law. NV Energy's generating stations utilize water for various purposes, including the plant cooling systems and process water for boilers. Water needed for the cooling systems comprises a large portion of the water requirements and although several of NV Energy's generating stations use recycled effluent or dry cooling or both (NV Energy 2011, p. 9), which minimize water use, water is still consumed in these processes through evaporation.

B. Methodology for Estimating External Water Costs

This section describes our methodology for estimating the additional costs of water consumption by Nevada Power and Sierra. The steps in our methodology are as follows:

1. Obtain historical monthly data on power plant water consumption (in gallons) and generation (in megawatt hours, "MWh");

2. Use historical monthly data on power plant water consumption and generation to estimate monthly plant water intensity (in gallons/MWh);

3. Obtain data on projected monthly plant generation under the IRP cases;

4. Use plant-specific water intensity and projected generation to estimate water consumption;

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[9] The Nevada's State Water Plan notes that most states recognize the following as types of beneficial use: (1) domestic and municipal uses; (2) industrial uses; (3) irrigation; (4) mining; (5) hydroelectric power; (6) navigation; (7) recreation; (8) stock raising; (9) public parks; and (10) wildlife and game preserves (NV DWR 1999, p. 6-1).

5. Develop information on the portion of consumed water that is owned by NV Energy;

6. Develop information on the value of water owned by NV Energy and used at its plants in Nevada; and

7. Use information on water consumption, water ownership percentage, and water value to estimate the additional costs of water consumption at NV Energy plants, i.e., external water costs that are not included in the PWRR.

These steps are described below.

1. Historical Water Consumption and Power Generation

NV Energy provided historical monthly data on water consumption and power generation at NV Energy power plants for calendar year 2020.

2. Water Intensity

Water intensity (gallons/MWh) was calculated using historical data on water consumption and power generation from NV Energy. Monthly water consumption was divided by monthly power generation to obtain the water intensity for a specific plant, year, and month. For plants that have not yet been built or for which there are no historical data available, we developed water intensity estimates by averaging the water intensities of similar plants based on information from NV Energy. We assume that water intensities will be constant over the analysis period (2022-2051).

3. Projected Generation

As described above, NV Energy provided PROMOD electricity market modeling results for the IRP cases. The PROMOD results for future plant generation by month were used in our calculations.

4. Projected Water Consumption

The monthly water intensity for each plant was multiplied by the projected monthly generation projections from PROMOD at each plant to produce monthly water consumption estimates at each plant over the analysis period (2022-2051).

5. Ownership of Consumed Water

Information on water ownership at each plant was supplied by NV Energy. Plant water needs are supplied by three sources: (1) Company-owned wells; (2) purchased water; and (3) leasing agreements. Water withdrawn from Company-owned wells is included in our calculations of additional water costs, while the costs from the other two sources—purchased water and leased water rights—are not included because we assume that these water costs will be included in the product rate paid by the Companies, and thus, in the PWRR. NV Energy also purchases electricity from other companies through contracts, renewable power purchase agreements, and spot market transactions. The full costs of water consumption for the power purchased by NV Energy are assumed to be included in the purchase prices and thus do not need to be calculated as additional costs.

Table 11 summarizes water ownership and leases for NV Energy plants.

Table 11. Water Ownership and Leases at NVE Plants

NVE Plants	Type	Company	NVE Water Ownership	NVE Water Lease (acre-feet)
Existing				
Chuck Lenzie	CC	NPC	0%	700
Clark	CC, CT	NPC	0%	6,748
Fort Churchill	CT	SPPC	100%	-
Harry Allen	CC, CT	NPC	0%	-
Higgins	CC	NPC	0%	252
Silverhawk	CC	NPC	0%	350
Tracy	CC, CT	SPPC	100%	-
Valmy	Coal	SPPC	100%	-
New				
X_2x1_SN	CC	NPC	100%	-
X_CT_NN	CT	SPPC	100%	-
X_CT_SN	CT	NPC	100%	-

Notes: "CC" denotes combined cycle units; "CT" denotes combustion turbines.
1 acre-foot = 325,851 gallons.
Source: NV Energy.

6. Water Value

In order to determine the water value estimates for plants owned by NV Energy in different geographical areas, we used geographical proximity to determine what existing values of water in Nevada would serve as good proxies for the price that NV Energy would have received for the water if NV Energy had instead sold it (and thus these values aim to capture the "opportunity cost" of NV Energy using the water).

For NV Energy's existing plants in Southern Nevada, we use the Southern Nevada Water Authority ("SNWA")'s budgeted wholesale delivery charge per acre-foot for fiscal years[10] 2020-

[10] Southern Nevada Water Authority's Fiscal Year ends on June 30th of each year.

2021 (SNWA 2021, p. 46) as an approximation for the value of the opportunity cost of water in Southern Nevada.

For the existing plants in Northern Nevada, we use information from the Truckee Meadows Water Authority ("TMWA"). The TMWA charges developers in the Reno metropolitan area for surface water rights in the Truckee Meadow. Prior studies (e.g., Weismann 2019) have used the prices charged by the TMWA as a measure of the market value of surface water rights in the region. The most recent price reported by TMWA is $7,700 per acre-foot, which we convert to an annualized cost of $629 per acre-foot.[11]

Finally, for the new plants that NV Energy plans on building in the future, we used prices applicable to the region they would likely be located. We used the SNWA's wholesale delivery charge as a proxy for plants in Southern Nevada and the cost of Truckee River water rights for plants in Northern Nevada.

The water value estimates are assumed to be constant in real terms over the analysis period (2022-2051). Table 12 shows these water values by plant. Note that water values are only relevant for plants consuming NV Energy-owned water (see previous table).

[11] We annualized the cost of the surface water rights over 30 years at the SPPC WACC of 6.75 percent; value is in 2022 dollars.

Table 12. Water Value Estimates by Plant

NVE Plants	Type	Company	Water Value (2022$ / acre-foot)	Water Value Proxy
Existing				
Chuck Lenzie	CC	NPC	-	-
Clark	CC, CT	NPC	-	-
Fort Churchill	CT	SPPC	$629	Truckee River Water Rights (1)
Harry Allen	CC, CT	NPC	-	-
Higgins	CC	NPC	-	-
Silverhawk	CC	NPC	-	-
Tracy	CC, CT	SPPC	$629	Truckee River Water Rights (1)
Valmy	Coal	SPPC	$629	Truckee River Water Rights (1)
New				
X_2x1_SN	CC	NPC	$339	SNWA Wholesale Delivery (2)
X_CT_NN	CT	SPPC	$629	Truckee River Water Rights (1)
X_CT_SN	CT	NPC	$339	SNWA Wholesale Delivery (2)

Notes: "CC" denotes combined cycle units; "CT" denotes combustion turbines; "Cogen" denotes cogeneration.
1 acre-foot = 325,851 gallons.
Real annual values were converted to nominal annual values using annual inflation rate information, as provided by NV Energy.
(1) Annualized price paid for surface water rights on the Truckee River, adjusted for inflation.
(2) SNWA's budgeted FY 2020-2021 Wholesale Delivery Charge.
Sources: SNWA 2020; TMWA 2021; NV Energy; NERA calculations as described in text.

7. Additional Costs of Water Consumption

The additional costs of water consumption resulting from NV Energy generation are calculated by multiplying the water price estimates by projected consumption of Company-owned well water. As previously mentioned, these monetary values represent the opportunity costs that NV Energy faces for its well-water use and are not reflected in the PWRR.

C. External Water Costs

1. External Water Costs for 2021 IRP Cases

Table 13 shows the estimated external costs of water consumption for the four resource cases.

Table 13. Present Values of External Water Costs, 2022-2051 (2022$ Millions)

Net-Zero	Iron_Hot	Repower Valmy	Geo
$11.5	$12.3	$20.2	$11.5

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy, before the present value was calculated using the nominal annual discount rates.

Sources: NV Energy; NERA calculations as explained in text.

2. External Water Costs Relative to Preferred Plan

Table 14 shows the differences in estimates of external costs of water consumption for the other three 2021 IRP cases relative to the Net-Zero case. The Geo case has the same water costs, while the Iron_Hot case has small additional water costs. The Repower Valmy case has substantial additional water costs, due mostly to water consumption at the Valmy plant.

Table 14. Differences in Present Values of External Water Costs, Relative to the Net-Zero Case, 2022-2051 (2022$ Millions)

Net-Zero	Iron_Hot	Repower Valmy	Geo
-	$0.8	$8.7	$0.0

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy, before the present value was calculated using the nominal annual discount rates.

Sources: NV Energy; NERA calculations as explained in text.

VI. Other Environmental Costs

In addition to quantified external costs related to air emissions and water consumption, we considered three other categories of potential environmental costs: (1) land use effects; (2) water quality effects; and (3) solid waste disposal, including sludge and ash disposal. For each category, we consider whether or not the environmental costs are likely to be substantial relative to the other environmental costs and whether there are likely to be significant differences in environmental costs among the 2021 IRP cases. We conclude that the environmental costs of these three categories are not likely to be substantial relative to the quantified environmental costs and that there are not likely to be significant differences in environmental costs among the cases.

A. Land Use Effects

As noted above, Nevada regulations call for quantification of environmental costs for air emissions, water and land use (NAC 704.9359). Land used by generating units and transmission facilities includes not only land for the equipment, but also land for disposal of liquid and solid waste (whether this disposal takes place on site or elsewhere). Actual expenditures on land for specific facilities are included in the operating costs calculated for those facilities (and the upfront costs of land purchases for new facilities). In this 2021 IRP, we rely upon the detailed analyses of potential environmental costs related to the land use effects of major transmission lines that we performed in 2020 for the Fourth Amendment to the 2018 Integrated Resource Plan[12] (Harrison et al. 2020), referred to here as “2020 IRPA” cases.

1. Analysis Conducted in 2020 IRPA Cases

For the 2020 IRPA cases, NERA developed detailed analyses of the potential environmental costs related to transmission land use. The sections below provide an overview and background and describe the principle sources of information, methodology, and conclusions of these analyses.

a. Overview and Background

The 2020 IRPA analyses used an environmental economics framework—equivalent to that used to evaluate other environmental costs for the cases—to evaluate whether the available information indicates that the environmental costs from land use effects of the transmission lines are likely to be significant. These assessments were based upon separate assessments for the individual ecosystem services potentially affected by the transmission lines included in each case. The available information was insufficient to quantify the specific changes in ecosystem services due to the transmission lines, much less to provide a basis for monetary evaluations of the environmental costs of these changes (such as we have provided for air emissions and external

[12] *See* Docket No. 20-07023, Technical Appendices ECON-7.

water use). Instead, we used the available information on the ecosystem services potentially affected by land use effects of the proposed transmission routes to develop qualitative evaluations.

Although the limited information means that dollar values—or even definitive qualitative evaluations—cannot be developed, the same general two-part approach to assessing environmental costs was used as for the other environmental cost categories. That is, we assessed both the nature of the environmental effects (analogous to increases in various health effects, such as hospital visits, for air emissions) and how these effects are valued in dollar terms (analogous to the dollar valuation of increased hospital visits). For land use changes, using the same two-part investigation, we considered (a) how the changes from the transmission lines would affect individual ecosystem services provided by the land (e.g., recreational services), and (b) how these changes might be valued (e.g., factors affecting the dollar valuation of any diminution in recreational services). Thus, the general approach was to evaluate effects on ecosystem services and on potential valuation based upon the current information. As noted, we assessed whether the available information indicates that these environmental land use effects of the transmission lines are likely to be significant, including accounting for opportunities to avoid adverse ecosystem service effects when actual routes are determined.

b. Principle Sources of Information

Our evaluations were based primarily on information developed by Power Engineers for NV Energy for the two major new transmission lines that would constitute Greenlink Nevada, Greenlink North and Greenlink West. Each of the two studies is labeled as a "Routing Constraint and Opportunity Study," and we referred to them as "Constraint Study North" and "Constraint Study West," respectively, and collectively as "the Constraint Studies" (Power Engineers 2020a and 2020b).

We supplemented the Constraint Studies with additional information developed for the 2020 Report based upon access to GIS-coded information. We also used information in the detailed final environmental impact statement ("FEIS") for the One Nevada ("ON Line") transmission line, a 236-mile, 500 kV transmission line in Nevada that allowed linkage of Nevada Power and Sierra generation resources, including renewable resources (DOI 2010). The ON Line FEIS provided information on how some highly site-specific adverse environmental effects were avoided during determination of the precise route, suggesting a similar process would be used for potential new transmission lines.

No equivalent constraint study was available for the other transmission segments included in the 2021 IRPA cases. As noted above and described in more detail below, we used the same information—including the Constraint Studies, the additional GIS-coded information, and the ON Line FEIS—to develop assessments for these transmission lines.

c. Methodology

Where information was available, we developed analyses for the following ecosystem services for the major transmission line projects included in each of the 2020 IRPA cases.

- *Wildlife Ecosystem Services*. The siting of the transmission lines could in principle adversely affect species potentially valued by users (e.g., recreators), and non-users (e.g., individuals who value the availability of the species for future generation). The transmission lines thus have the potential to result in both use and non-use effects, depending upon the significance of the physical effects to the species present in the study area (e.g., size of the incremental effects relative to existing conditions), as well as how these changes could result in dollar values (e.g., factors such as the uniqueness of the population affected).

- *Water Quality Ecosystem Services*. The siting of the transmission lines could adversely affect waterbodies that provide water quality services potentially valued by direct users (e.g., residents) or indirect users (e.g., recreators interested in species using the waterbodies). The transmission lines thus have the potential to result in direct and indirect use effects on water quality services, depending upon the significance of the physical effects to the waterbodies present in the study area (e.g., whether the changes are incremental relative to existing conditions), as well how these changes might result in diminished dollar value.

- *Soils and Sediment Management Ecosystem Services*. There are three types of potential impacts on soils and sediment management. First, there could be physical changes such as compaction and crushing during construction of structures and during the salvaging and replacement of soil before and after that construction. Second, soil disturbances could affect the soil's productivity as measured by the rate of vegetation production. Lastly, soil disturbances could cause or exacerbate soil loss/erosion. Erosion potential is determined based on physical soil characteristics, including slope—areas located on steep slopes are inherently susceptible to erosion.

- *Aesthetics Ecosystem Services*. The siting of the transmission lines could adversely affect viewsheds that provide aesthetic services potentially valued by users (e.g., recreators, incidental viewers). The transmission lines thus have the potential to result in use effects, depending upon the significance of the physical effects to the scenic features of the study area (e.g., whether the changes are incremental relative to existing conditions), as well how these changes result in diminished dollar value (e.g., whether the land is valued for its scenic features).

- *Cultural Services*. The siting of the transmission lines could damage cultural sites and alter the scenic features of the cultural sites. The transmission lines thus have the potential to result in use and non-use effects on cultural resources, depending upon the significance of the physical effects to the cultural sites present in the study area (e.g., whether the changes in aesthetics are incremental relative to existing conditions), as well how these changes might result in diminished valuation.

For each of the ecosystem services, we first identified the specific environmental factors noted in the route-specific information from the Constraint Studies and then evaluated the likely significance of those factors as well as similar factors for segments not included in the Constraint Studies, both using other information.

d. Conclusions on Environmental Costs of Transmission Land Use for the 2020 IRPA Cases

We concluded that the existing information did not indicate significant environmental costs related to land use effects of any of the major transmission lines included in the 2020 IRPA cases. This conclusion is based upon detailed evaluations of the available information on potential ecosystem effects of the transmission lines.

Our conclusions for the individual cases led us also to conclude that the existing information does not indicate that the 2020 IRPA cases differ in terms of the environmental costs related to transmission land use effects.

2. Implications of the 2020 IRPA Analyses for Conclusions on Environmental Costs of Transmission Land Use for the 2021 IRP Cases

Based on our evaluation of land use effects for the transmission lines included in the 2020 IRPA cases and the similar nature of the transmission resources in the 2020 IRPA cases and the 2021 IRP cases—namely, the inclusion of the Greenlink Nevada transmission project as the only major additional transmission upgrades in all 2021 IRP cases—we believe that the conclusions developed for the 2020 IRPA cases would also apply to the 2021 IRP cases. Thus, we do expect that the 2021 IRP cases would result in significant environmental costs associated with transmission land use. Moreover, electric generation resources have relatively small and highly localized land use effects, so we do not expect the land use effects for electric generation resources would result in significant environmental costs either. As a corollary to both these conclusions, we do not expect the land use effects to vary in any significant degree among the four 2021 IRP cases.

Note also that the environmental effects of major transmission lines would be the subjects of future detailed environmental impact statements that would be prepared as part of the granting of rights of way through land administered by the U.S. Bureau of Land Management ("BLM"). The granting of a right-of-way for the transmission projects is a federal action that would trigger environmental review under the U.S. National Environmental Policy Act ("NEPA"). Thus, much more information would be available on the environmental effects of major new transmission lines if and when these environmental studies would be completed, in contrast to the information that is now available.

B. Water Quality Effects

The U.S. Clean Water Act establishes effluent standards for new generating units. Nevada applies these same water quality standards to all generating units, existing as well as new (NRS § 445A). However, facilities in the Nevada Power and Sierra systems do not release water effluent in surface waters, but rather use evaporation ponds to dispose of their liquid wastes.

The impact of pollutants deposited in these evaporation ponds is largely dependent upon the method of containment utilized and the depth of adjacent ground water. The evaporation ponds for existing and new facilities in the Nevada Power and Sierra systems have double liners and monitoring equipment to detect any groundwater leakage. Thus, contamination of groundwater is unlikely. Moreover, because groundwater depth varies significantly by location—from a few feet to a few hundred feet (La Camera et al. 2005)—water quality impacts are best examined on a site-specific basis. Note that actual expenditures on liquid waste disposal for specific facilities would be included in the operating costs calculated for those facilities. In any event, we understand that NV Energy does not believe that there would be significant differences among the four additional cases in terms of water pollutants placed in the evaporation ponds.

C. Solid Waste Effects

Different generating units often produce different amounts of solid waste during operation—and at different rates. For example, coal-fired technologies generally produce more solid waste than gas-fired technologies (EPA 2014). Actual expenditures on solid waste disposal for specific facilities would be included in the operating costs calculated for those facilities. Potential environmental impacts from solid waste disposal would depend on surface depth of groundwater and would be best examined on a site-specific basis. However, the potential for environmental damages is low because all facilities in the Nevada Power and Sierra systems, and any other entities providing solid waste disposal services, must meet stringent federal standards for landfills. We do not expect that the different cases currently under consideration would result in materially different amounts or environmental costs related to solid waste disposal.

VII. Economic Impacts

This chapter provides information on the economic impacts of constructing and operating generation and transmission facilities under the alternative cases. The chapter begins with an overview of the regulatory context, specifically Section 704.9357 of the NAC. That NAC section refers to the requirement to calculate "net economic benefits," which are commonly referred to as "economic impacts," the term we use in this report. The chapter provides background on the nature of the potential positive and negative economic impacts of resource plans and describes the economic impacts model we use to develop our estimates. The final sections of the chapter describe the methodology we use for the analysis and provide our estimates of the economic impacts in Nevada of the alternative cases.

A. Regulatory Context

Nevada regulations provide instructions to utilities on performing economic impact analyses related to resource plans. Section 704.9357 of the NAC states as follows:

1. An analysis of the changes that result in net economic benefits to Nevada from electricity-producing or electricity-saving resources must be conducted by the utility in selecting a resource option. The net economic benefit to the State must be quantified to reflect both the positive and negative changes and must include the net economic impact of renewable resources. The projected present worth of societal cost of a competing resource plan must be within 10 percent of the lowest societal costs plan before proceeding with an analysis of the economic benefits to Nevada.

2. The economic benefits analysis must be achieved by calculating the portion of the present worth of future requirements for revenue that is expended within the State, including the following for both the construction and operation phases of any project:

    a. Capital expenditures for land and facilities located within the State or equipment manufactured in the State;

    b. The portion of the cost of materials, supplies and fuel purchased in the State;

    c. Wages paid for work done within the State;

    d. Taxes and fees paid to the State or subdivisions thereof; and

    e. Fees paid for services performed within the State.

3. In the analysis, the utility shall consider only the net benefit added to the economy of the State of that portion of expenditures made within the State.

4. The present worth of societal costs of the competing resources must then be adjusted by the Commission to take into consideration either all, or only a portion, of the calculated economic benefit.

5. As used in this section, "net economic impact of a renewable resource" means the present worth of economic costs of a contract for a renewable resource minus the present worth of economic development benefits to the State over a 20-year period.

Note that all of the items listed in Section 704.9357(2) relate to expenditures, which produce positive economic impacts (as discussed below in the section on conceptual framework). The regulation does not include any specific language on how to assess the negative economic impacts of higher electricity prices. Note too that Section 704.9357(5) defines the "net economic impact of a renewable resource" as the difference between contract costs and economic benefits (both measured in present value), but this calculation combines two different types of economic measurements and thus could be misleading. This issue is discussed in the section below on conceptual framework.

Note also that the requirement to model negative impacts (i.e., financing effects) does not require that the empirical estimates of the differences among the cases, including the difference between the baseline case and the other cases, to be negative. It is possible, for instance, that the "negative impacts" of financing are smaller—i.e., less negative—in a particular case when compared to the baseline. In this case, the financing impacts have a positive value, but still fulfill the requirement to model negative impacts.

B. Background on Economic Impacts

This section provides background on economic impacts, including discussions of the nature and categories of economic impacts and alternative methods for developing estimates.

1. Nature of Economic Impacts

Economic impacts are defined in general terms as the gains and losses in economic activity that arise as a result of market transactions. In market economies such as the United States, the actions of each market participant affect other market participants through impacts on prices or quantities without causing market inefficiencies. Consider the impacts that arise when the demand for a particular good (e.g., automobiles) increases. If the supply curve for the good is upward sloping (i.e., additional supply would be produced at higher prices), increased demand by some consumers increases the market price, increasing the costs for other consumers of that good. However, the negative effect of the higher price on consumers is exactly matched by an increase in revenues to producers, so that the change in income represents a *transfer* from one group to another, not a net change in the social cost of providing the automobiles.

A similar process is at work if one considers the employment effects of an increase in demand for Nevada's hotel rooms. Employment will increase in the tourism industry (and, as discussed below, in other sectors as well). However, the overall employment in the tourism industry is determined by other economic forces such as the U.S. and foreign economies, jet fuel costs, currency exchange rates, interest rates, and aggregate demand. An increase in tourism employment in Nevada generally would be compensated for by decreases in tourism in competing destination resort areas whose demand would decrease to accommodate increased spending in Nevada. Note, however, that the increase in tourist-related economic activity in Nevada would be a net positive impact from the perspective of Nevada.

These economic impacts are sometimes referred to as "pecuniary externalities," because they lead to gains and losses for different groups. Such effects typically do not lead to inefficiencies in the allocation of resources. In contrast, traditional externalities could lead to inefficiencies in the allocation of resources. Information resulting from knowledge of externalities can be used to reduce or eliminate the inefficiencies.

2. Categories of Economic Impacts

Economic impacts measure the changes in economic activity in Nevada over the relevant time period for the 2021 IRP (in this case 2022-2051 based on the time horizon of inputs for the economic impacts analysis from NV Energy). The four categories of economic impacts we consider are as follows:

1. Gross state product (total value of final goods and services);

2. Employment;

3. Personal income; and

4. State and local tax payments.

This section shifts the focus from the general nature of economic impacts to the specific effects of the cases on the State's economy. We begin with a general overview and then develop a typology for the various sources of economic impacts. The typology answers the following question: What are the potential economic impacts of selecting a *more expensive* resource plan over a less expensive plan?

a. Overview

The construction and operation of a major power plant can have a noticeable effect on the economy of the region in which it is located. Local jobs are expanded when the plant is built, reflecting the increased demand for construction and other related personnel. Once operating, a power plant becomes a local employer as well. The jobs associated with both the construction and the operation of the plant are typically referred to as "direct" impacts of the facility.

Besides being employers, power plants generate additional jobs as a result of being part of the overall regional economy. Utilities operating power plants purchase various goods and services from the local economy, effects that are often referred to as "indirect impacts." In addition, employees who work at the plant (either in the construction phase or when the facility is in operation) or in indirectly affected sectors spend money in the local economy, which tends to increase jobs through what are referred to as "induced impacts." The cumulative effects of these indirect and induced activities are often referred to as "multiplier" effects because the direct jobs tend to be multiplied as the effects percolate through the economy.

From the perspective of the utility resource facilities themselves, more expensive plants typically generate larger economic impacts. Higher costs mean more people are required to construct and operate the facilities and more goods and services are needed to run the plant. These higher payrolls create greater multiplier effects on the state economy. These added costs, however, generally are paid for by Nevada residents in the form of higher electricity rates (although, as noted below, the situation can be different if some costs are subsidized by the federal government, as in the case of renewable resources). The positive impacts of greater construction and operating expenses therefore are likely to be counterbalanced by the negative impacts of the financial arrangements required to pay for the more-costly facilities.

Electric utility ratepayers thus ultimately could pay for the added construction and operation expenses of more expensive new power plants and resource plans (assuming federal subsidies do not compensate for the added expenses). All ratepayer groups (i.e., residential, commercial, or industrial) would pay these additional costs. Residential ratepayers would have to forego other consumption as a result of higher electricity rates. Commercial and industrial firms facing higher rates would face higher costs in comparison to competitors in other states. Nevada firms could respond to the increased electricity rates by increasing prices for their products, substituting other factors of production for electricity, or reducing output, depending upon their market circumstances. These higher prices and reduced output—as well as the reduced consumption of other goods and services by residential customers—would lead to negative multiplier impacts that are analogous to the positive multiplier impacts outlined above. Both positive and negative impacts should be considered in a comprehensive assessment of economic impacts.

As noted above, there is an important caveat for resources whose owners receive subsidies from outside Nevada. In the case of solar resources, as explained below, the federal government provides subsidies that lower the cost to NV Energy. The presence of federal subsidies means that greater expenses in constructing solar resources do not necessarily translate into greater NV Energy rates.

b. Nevada State Perspective

Based on the regulations cited above, the economic assessments conducted for this study concentrate on the economic impacts of utility resource choices *in Nevada*. This in-state perspective has important implications for determining the relative contributions of different energy technologies. Two technologies may have the same overall costs and require the same total number of jobs, but one of the technologies may involve greater purchases in Nevada. For example, one technology may involve components manufactured within the State, while the other may involve the assembly of components manufactured in other jurisdictions. The net result could be very different economic impacts within the State. Similarly, the origin of the fuel for different technologies would affect the economic impacts within Nevada.

c. Contrasts with Other Economic Measures

Although often referred to as "economic benefits," economic impacts differ from the benefits and costs of public or private projects. In the case of a new generation facility, the social benefit is the power produced by the facility for society to use and the social costs represent the opportunity costs of the resources used as well as the external (e.g., environmental) costs. Cost-benefit analysis involves comparing the social costs and social benefits of public or private projects to determine whether society would be better off with or without the projects. Neither costs nor benefits in cost-benefit analyses measure the economic impacts, i.e., the net changes in economic activity due to the program or policy. The calculation of economic impacts thus is separate from the calculation of costs and benefits.

These differences mean that economic impacts of the additional cases are not comparable to the costs of the cases, as reflected in the PWRR. Although resource plans with a larger PWRR generally would have greater positive impacts, the more expensive plans also would tend to require larger electricity rate increases (subject to the caveat regarding federal subsidies noted above). Moreover, the positive impacts of expenditures in Nevada would depend upon the fractions of expenditures in Nevada, which could differ by plan. Finally, economic impacts do not account for any associated environmental costs of resource plans, which would be included in a comprehensive social cost-benefit analysis.

d. Net Economic Impacts of Renewable Energy Projects

The net economic impacts of renewable energy projects receive particular attention in the Nevada regulations. The positive impacts derive from the expenditures to construct and operate renewable energy facilities. These positive impacts are sensitive to whether the goods and services to construct and to operate such facilities come from in-state suppliers or out-of-state suppliers, as reflected in the "regional purchase coefficients" for various expenditure categories. For example, if renewable energy cost more to produce than fossil fuel energy even with federal subsidies,[13] then utilities will charge higher electricity prices to compensate for these higher costs; these higher prices would lead to negative economic impacts. In that case, estimating the net economic impacts of renewable energy projects therefore would involve calculating the positive impacts due to the higher costs for renewables relative to fossil fuel sources—accounting for differences in the regional purchase coefficients for the various expenditures—as well as the negative effects of these higher costs through higher electricity price effects relative to fossil energy.

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[13] This simple example is provided for illustrative purposes to explain the key mechanisms that affect the net economic impact results for renewable resources. It is not necessarily indicative of the results from the present analysis, which are included in Section VII.F. The future cost of energy production from renewables relative to fossil fuels is uncertain. It is certainly possible that renewable energy could cost less to produce than fossil fuel energy in future years.

As noted above, for renewables the net economic impacts also depend on the presence of federal subsidies, which reduce the cost to developers of renewable resources and thus the likely prices paid by NV Energy and, as a result, reduce potential electricity rate increases due to renewables. The Business Energy Investment Tax Credit ("ITC") is a federal tax credit that reduces the costs of installing solar resources for the residential, commercial, and utility sectors. For commercial and utility-scale projects, the ITC is scheduled to decline from 26 percent in 2021 to 22 percent at the end of 2022. At the end of 2023, residential credits drop to zero percent, while commercial credits drop to 10 percent and holds there. Commercial and utility-scale projects which have commenced construction before December 31, 2023 may still qualify for the 26 or 22 percent ITC if they are placed in service before January 1, 2026 (SEIA 2021). These subsidies reduce the capital costs that developers would incur to install solar resources, which results in lower cost recovery requirements over the lifetime of the project. This translates into a lower bid price for the PPA between the facility owner and the utility, which ultimately lowers the amount that the utility would need to recover through the rate base.

From a state economic impact perspective, under this federal tax credit Nevada would enjoy the full positive economic contributions (subject to the regional purchase coefficient ("RPC") assumptions) associated with the construction of the resource (i.e., the construction workers still receive full wages); however not all of the project costs would be recovered from NV Energy ratepayers since some of the financing would come from out-of-state funds (i.e., the value of the federal tax credit).

All these considerations suggest that the current definition of the net economic impacts of a renewable resource contained in the regulations—"the present worth of economic costs of a contract for a renewable resource minus the present worth of economic development benefits to the State over a 20-year period"—could be misleading for three reasons.

1. *"Apples and oranges" problem*. The two categories measure different concepts. The contract costs measure the costs to the company over the contract life, and the economic development benefits include the sum of the direct and multiplier (indirect and induced) effects of the expenditures in Nevada.

2. *Contract costs versus expenditures*. The contract costs to NV Energy may not provide a measure of full project costs/expenditures, primarily because of government subsidies for renewables. The federal government subsidizes renewable development, and thus contract prices are lower than based on the full costs of the renewable resources (and thus the full expenditures that determine the positive economic impacts).

3. *Negative rate impacts not included*. The regulations do not appear to account for the potential negative effects of the likely higher electricity rates from renewables (assuming that the net effect of adding a renewable resource would be a greater PWRR and thus higher electricity rates).

The basic methodology for determining economic impacts suggests instead defining the net economic impacts of a renewable resource as net effects of the renewable relative to the impacts of providing the same generation with fossil fuel resources. Such calculations would account for the effects of differences in both expenditures and electricity rates due to the use of renewable energy.

C. Potential Positive and Negative Economic Impacts

This section discusses the potential positive and negative economic impacts of the cases, drawing on the background provided above. Note that our analysis is based upon the costs and revenue requirements related to NV Energy's "native load" customers and do not include costs and revenues related to entities that purchase transmission capacity from the Companies ("transmission-only customers"), as the PWRR cost information is based on "native load" customers.

1. Positive Direct Expenditure Impacts

The construction and operation of a more expensive power plant lead to more *direct* demands for labor and for goods. Engineering cost estimates typically provide the details on the individual items included in these direct impacts. Construction elements include payments for site preparation, physical plant (e.g., utility boilers), support facilities, water and sewer facilities, direct labor costs for assembly, and other costs. Elements of ongoing operating costs include costs to purchase the relevant fuels as well as labor and materials needed to operate and maintain the facility.

There are some project costs that are not relevant for an economic impact assessment. The most important category is land acquisition. Land costs should be excluded from an economic impact assessment because they do not represent real economic activity, but rather transfers of funds from one party to another. In contrast, site preparation costs should be included in the economic impact assessment. Another category of costs that might be excluded from the economic impact assessment is government expenditures, such as the costs for roads, bridges, and other infrastructure. Unless the offsetting impacts of their financing are included, including these impacts would tend to overestimate the economic impacts of the facilities. An alternative approach is to include both the positive impacts of government expenditures and the negative impacts of their financing, i.e., the offsetting reductions in disposable income due to the added state and local taxes required.

2. Positive Expenditure Multiplier Impacts

The expenditures involved in constructing and operating an electric utility plant or a transmission line represent the first round of a multi-round process. The first round consists of the employment and output related directly to construction and operation. The next round ("indirect") involves purchases from local companies related to construction and operation (e.g., purchase of local supplies for use at the facility). These direct and indirect purchases give rise to subsequent rounds of induced expenditures for labor and other inputs. For example, the construction of a power plant or transmission line initially requires labor to clear and prepare the site. Those laborers spend part of their wages on products and services in Nevada, such as food and housing. Providing food and housing services in turn requires other Nevada products and services, including the food itself and the labor to run retail stores and restaurants.

The net effect of these subsequent rounds of expenditures is a "multiplier" effect on the Nevada economy from the initial direct expenditures. The size of the multiplier—typically calculated as the ratio of total direct, indirect and induced impacts to the direct impacts—depends upon the geographic scope. Multipliers are larger for larger geographic areas, because more of the indirect and induced impacts occur within the boundaries. Thus, the multiplier calculated for the individual county within which a power plant is located would be smaller than the state multiplier, which would be smaller than a multiplier for the entire nation.

3. Negative Direct Financing Impacts on Customers

Utilities have to finance the costs of constructing and operating more expensive electric generating resources, although, as noted above, federal subsidies reduce the additional costs to Nevada ratepayers. Although the costs initially might be covered by bond or other financing mechanisms, ultimately the costs will be recovered from electric utility ratepayers in the form of higher electric rates, including residential, commercial and industrial customers. Higher residential electric rates reduce the income that Nevada residents have to spend on other goods and services. These impacts on Nevada residents will be translated into reduced Nevada employment and other economic activity.

4. Negative Impacts on Business Location Due to Higher Electricity Rates

Higher electricity rates also affect the desirability of a state as a location for new or expanded industries. Industries can face choices of alternative locations that are similar with respect to non-energy inputs such as work force skills and availability of raw materials. The more dependent a particular industry is upon electricity as a production input, the greater are the cost impacts of higher electricity rates, and therefore the more likely it is that higher electricity rates will be a crucial factor for businesses deciding where to locate a new facility or whether to expand an existing facility. In general, higher electricity rates for commercial and industrial customers will decrease the competitiveness of Nevada firms and thereby decrease employment in Nevada.

Note that, as discussed above, the economic impacts modeling looks at the differences among cases, in particular the differences in the IRP cases relative to the baseline case. Thus, it is possible for the negative impacts of financing for a particular case to be smaller—i.e., less negative—when compared to the baseline. In this case, the financing impacts have a positive value, but still fulfill the requirement to model negative impacts.

5. Negative Financing Multiplier Impacts

As with the expenditures to construct and operate power plants, the expenditures foregone by ratepayers and the impacts on businesses and their consumers from revenue requirements will have secondary and subsequent round expenditure impacts on the State economy. These subsequent round multiplier impacts lead to additional employment impacts that must be included when calculating the overall employment impacts of alternative cases.

D. Regional Economic Models, Inc. (REMI) Model

1. Overview

This section provides an overview of the model we used to estimate economic impacts. The REMI model provides a detailed representation of a state or region's economy. Appendix I to this report provides an overview of REMI. The core of the model is a set of input-output ("I-O") relationships among different industries. These relationships show how industries are related to one another, in terms of both inputs and outputs. Thus, they allow one to estimate how changes in one industry will affect demand in other industries (those that supply inputs to the industry in question) or supply in other industries (those that purchase outputs from the industry). In addition, I-O models can be used to trace through the impacts that result from changes in the incomes of workers in the affected industry. This input-output framework thus captures earnings and employment impacts resulting from the direct expenditures on construction and operation of a plant as well as the indirect and induced expenditures.

This input-output formulation also accounts for the amount of "economic leakage" (i.e., the percentage of total expenditures made on imported goods outside the economy). For example, the construction of a power plant may require boilers purchased from outside the state. As a result, the indirect and induced economic impacts of that purchase occur outside the state as well.

REMI provides many other important linkages beyond those included in the input-output relationships. The model provides dynamic results over long time periods (e.g., 20-30 years) and outputs for detailed sectors of the economy, including detailed industry and occupation groups. REMI can provide estimates of the impacts on the regional economy over a planning horizon of higher electric rates when all the feedback mechanisms in the economy are considered. For example, the REMI model estimates the changes in wages that result from changes in economic activity. If employment increases in a region or state, wages will tend to rise, affecting the competitive position of the region relative to other areas. These effects are estimated in a dynamic framework that projects the effects over twenty years or more.

2. Uncertainties and Complications

Although REMI contains detailed recent data for many industries from several government agencies and other public sources, it cannot capture the actual flows of money throughout the economy with complete accuracy. As with other regional models, the REMI model uses the same regional purchase coefficient for all companies within an industry, but in fact the supply chains of companies within an industry may differ significantly. The approximations are especially rough for small industries serving niche markets.

Another important limitation of REMI and other economic impact models for analyzing resource plans is their lack of information on land values and tax rates for individual properties. The models cannot capture changes in land values from construction of generation or transmission facilities, and they cannot estimate property tax payments without detailed information on where facilities would be built. This issue is especially relevant for renewable energy facilities in Nevada because they receive a property tax exemption under state law. Renewable energy facilities in Nevada also have lower rates for sales and use taxes (Nevada Legislature 2011).

3. Other Economic Impact Models

Other economic models exist and have been used and discussed in prior IRPs. In particular, there was discussion in the 2020 IRPA of whether the IMPLAN model could be appropriately used for the modeling of economic impacts for an IRP. The following describes the IMPLAN model and discussed why it is not appropriate for this use.

a. Overview of IMPLAN Model

IMPLAN is an empirical model that is widely used to estimate the "multiplier" effects of expenditures to build and operate a public or private facility (e.g., power plant). Economists at the University of Minnesota developed the IMpact analysis for PLANing or IMPLAN model for use by the U.S. Forest Service in 1979. The model is currently maintained and licensed by the IMPLAN Group (IMPLAN 2021).

IMPLAN computes the "multiplier" effects of increased expenditures based upon an input-output ("I-O") table for Nevada. This I-O table relates the outputs of each industry to inputs from other industries (including the industry itself). The I-O formulation allows the modeler to estimate how changes in one industry will affect demand for other industries (those that supply inputs); these are the "indirect" impacts. In addition, I-O models can be used to trace through the impacts from changes in worker income; these are the "induced" impacts. These impacts account for the "economic leakage" from expenditures, i.e., the percentage of expenditures that increase demand for goods and services outside the region.

b. Limitations of IMPLAN Model

As an I-O model, IMPLAN cannot model the behavioral responses of firms and households to potential Nevada cost and price changes due to the alternative IRP cases. Thus, IMPLAN cannot reliably model the negative effects of increases in a Nevada business's costs on its sales due to it becoming less competitive with businesses outside Nevada. As I have emphasized, modeling these negative effects is critical to obtaining valid estimates of the net economic benefits in Nevada of alternative IRP cases.

Moreover, as a static "snapshot" model that does not include changes over time, IMPLAN also is not able to estimate changes over time in the effects of increased business costs. The model cannot model, for example, the impacts on labor markets and the resulting impacts on the Nevada economy over time.

Note that some of these same limitations apply to estimates of the positive impacts of changes in expenditures; IMPLAN cannot estimate the dynamic effects of changes in expenditures on labor markets, for example. But, as I mentioned above, these market effects tend to be "second order" effects with regard to the positive expenditure impacts. In contrast, the competitive effects of greater business costs represent fundamental behavioral responses to higher costs/prices that must be estimated in order to provide reliable estimates of the "negative changes" due to alternative IRP plans.

c. Use of REMI

The REMI model is a dynamic policy analysis model that integrates various modeling approaches, including I-O analysis, econometric analysis, and general equilibrium theory. Although REMI includes the underlying I-O relationships that are included in IMPLAN, it includes a much richer modeling framework. Critical to the application here, REMI includes behavioral relationships that allow estimation of the competitive effects of higher business costs on Nevada economic activity. Thus, in contrast to IMPLAN, REMI can be used to develop reliable estimates of the negative financing effects of more expensive resource cases on the Nevada economy.

REMI provides other advantages over IMPLAN because of its modeling of market effects over time. For example, the REMI model estimates the changes in wages that result from changes in economic activity in the State. If employment increases in Nevada, wages will tend to rise, affecting the competitive position of the State relative to other states. These and other effects are estimated in a dynamic framework that can project annual impacts over the full analysis period from 2022 to 2051. Indeed, although results are often summarized in terms of annual averages over the 30-year period, the REMI model provides much richer results that show how the relative impacts of different IRP plans tend to change over the 30-year period.

E. Economic Impact Methodology and Inputs

1. Overview of Methodology

Estimates of economic impacts in REMI require a "baseline" or reference scenario to which "alternative" scenarios can be compared. NV Energy developed a Base case to be used as the baseline for REMI modeling. It most closely approximates the status quo of resources and expenditures in NV Energy's generation fleet. Thus, the inputs to the REMI model are not the absolute values for the various cases but rather the differences between expenditures and revenues for each of the cases relative to this Base case.

Although the modeling for the cases relies on changes relative to the REMI baseline, the differences of most interest are the effects of the other cases on the Nevada economy relative to the Preferred Plan, the Net-Zero case. Thus, we present results for the other three cases relative to the Net-Zero case.

The remainder of this section provides details on the inputs to the REMI modeling, including the expenditures and electricity revenues. As discussed below, some expenditure categories are not included in the economic impact analysis. Market purchases, for example, are excluded from the economic impacts analysis because we understand they would not likely involve expenditures in Nevada, and therefore they would not likely have significant in-state economic impacts. Inputs to the economic impact analysis related to renewable energy power purchase agreements are based on cost parameters from the U.S. Energy Information Administration ("EIA") rather than NV Energy's contract costs because the contract costs may differ significantly from likely expenditures. Thus, the total expenditures calculated for the economic impact analysis differ from the total expenditures calculated by NV Energy for the PWRR.

2. Inputs for Positive Economic Impacts

a. Construction Expenditures

Construction expenditures for new generation and transmission facilities include payments for site preparation, buildings, equipment, engineering labor, and construction labor. Table 15 shows the annual average construction expenditures over the period from 2022 to 2051 by category for each of the four IRP cases. Table 16 compares the values for the four IRP cases to the Base case. This comparison shows that construction expenditures for the Iron_Hot case are very similar to those in the Base case and construction expenditures are slightly higher for the Repower Valmy case due mostly to increased solar PV and battery storage. The Net-Zero and Geo cases have substantially greater construction expenditures on renewable power purchases, which is slightly offset by decreased new fossil generation. Appendix J provides information on expenditures by year.

Table 15. Average Annual Construction Expenditures, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
NVE Existing Generation	**$0**	**$0**	**$0**	**$0**	**$0**
CCs	$0	$0	$0	$0	$0
CTs	$0	$0	$0	$0	$0
Coal	$0	$0	$0	$0	$0
NVE New Generation	**$124**	**$134**	**$135**	**$90**	**$90**
CCs	$25	$31	$31	$31	$31
CTs	$89	$89	$89	$45	$45
Cogen	$0	$0	$0	$0	$0
Solar PV	$4	$4	$4	$4	$4
Battery Storage	$6	$10	$10	$10	$10
Valmy Repower	$0	$0	$1	$0	$0
Power Purchases	**$748**	**$748**	**$823**	**$1,130**	**$1,085**
CCs	$0	$0	$0	$0	$0
CTs	$0	$0	$0	$0	$0
Coal	$0	$0	$0	$0	$0
Cogen	$0	$0	$0	$0	$0
Solar PV	$420	$420	$456	$570	$569
Solar Thermal	$0	$0	$0	$0	$0
Battery Storage	$327	$327	$366	$502	$501
Wind	$0	$0	$0	$10	$15
Geothermal	$0	$0	$0	$48	$0
Hydro	$1	$1	$1	$1	$1
Heat Recovery	$0	$0	$0	$0	$0
Landfill Gas	$0	$0	$0	$0	$0
Market	Not incl.	Not incl.	Not incl.	Not incl.	Not incl.
Power Transmission	**$22**	**$22**	**$22**	**$25**	**$25**
Financing	**$9**	**$9**	**$9**	**$7**	**$7**
Gas Transmission	**$0**	**$0**	**$0**	**$0**	**$0**
Open Position	**$62**	**$57**	**$49**	**$49**	**$48**
Total	**$966**	**$971**	**$1,039**	**$1,301**	**$1,255**

Notes: All values are annual averages for the period 2022-2051 in millions of 2022 dollars.
"CCs" denote combined cycle units; "CTs" denote combustion turbine units; "Cogen" denotes cogeneration.
"Not incl." denotes that market purchases are not included as relevant expenditures for the economic impacts analysis because they are assumed to occur outside Nevada.

Source: NERA calculations as explained in text.

Table 16. Average Annual Construction Expenditures, Relative to the Base Case, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
NVE Existing Generation	**-**	**$0**	**$0**	**$0**	**$0**
CCs	-	$0	$0	$0	$0
CTs	-	$0	$0	$0	$0
Coal	-	$0	$0	$0	$0
NVE New Generation	**-**	**$10**	**$11**	**-$34**	**-$34**
CCs	-	$6	$6	$6	$6
CTs	-	$0	$0	-$44	-$44
Cogen	-	$0	$0	$0	$0
Solar PV	-	$0	$0	$0	$0
Battery Storage	-	$3	$3	$3	$3
Valmy Repower	-	$0	$1	$0	$0
Power Purchases	**-**	**$0**	**$75**	**$382**	**$337**
CCs	-	$0	$0	$0	$0
CTs	-	$0	$0	$0	$0
Coal	-	$0	$0	$0	$0
Cogen	-	$0	$0	$0	$0
Solar PV	-	$0	$36	$150	$149
Solar Thermal	-	$0	$0	$0	$0
Battery Storage	-	$0	$39	$174	$173
Wind	-	$0	$0	$10	$15
Geothermal	-	$0	$0	$48	$0
Hydro	-	$0	$0	$0	$0
Heat Recovery	-	$0	$0	$0	$0
Landfill Gas	-	$0	$0	$0	$0
Market	Not incl.	Not incl.	Not incl.	Not incl.	Not incl.
Power Transmission	**-**	**$0**	**$0**	**$3**	**$3**
Financing	**-**	**$0**	**$0**	**-$2**	**-$2**
Gas Transmission	**-**	**$0**	**$0**	**$0**	**$0**
Open Position	**-**	**-$5**	**-$13**	**-$14**	**-$14**
Total	**-**	**$5**	**$73**	**$334**	**$289**

Notes: All values are annual averages for the period 2022-2051 in millions of 2022 dollars.
"CCs" denote combined cycle units; "CTs" denote combustion turbine units; "Cogen" denotes cogeneration.
"Not incl." denotes that market purchases are not included as relevant expenditures for the economic impacts analysis because they are assumed to occur outside Nevada.

Source: NERA calculations as explained in text.

Table 17 shows the source of construction expenditure estimates for each category of expenditure as well as our methodology for estimating the economic impacts of construction expenditures using REMI. The five categories that entail construction expenditures are: (1) NV Energy new fossil fuel generation (i.e. natural gas) facilities; (2) NV Energy new renewable generation (i.e. solar PV) facilities; (3) NV Energy new purchases of renewable energy; (4) NV Energy open positions to meet capacity requirements; and (5) NV Energy's new transmission facilities. Financing costs for these construction projects are input separately and thus represent an additional category of construction expenditures. Note that there are no construction expenditures for NV Energy's existing generation or purchases from specific fossil facilities (all of which have already been built). We also do not include construction expenditures related to out-of-state facilities. In addition, because the majority of market purchases are assumed to come from out-of-state facilities, market purchases are assumed not to lead to significant construction expenditures in Nevada.

Table 17. Economic Impact Methodology for Construction Expenditures

Category	Expenditures Source	Impacts Methodology in REMI
New Fossil Generation	NVE	Input as increased demand for various sectors (see below)
New Transmission	NVE	Input as increased demand for various sectors
New Renewable Generation	NVE	Input as increased demand for various sectors (see below)
Renewable Purchases	NERA based on EIA and NVE	Input as increased demand for various sectors (see below)
Open Position	NVE	Input as increased demand for various sectors (see below)
Financing	NVE	Input as increased demand for the securities and financial activities sector

Notes: Expenditures on out-of-state facilities are not included. Market purchases are assumed to be out of state; thus, we exclude them from the economic impact analysis.

NV Energy provided cost estimates for its open position in future years to reflect capacity requirements to ensure the reliability of the local electricity region. These costs are included in the PWRR. Based on discussion with NV Energy experts, we determined that some of the open position costs could reasonably be included in the economic impacts analysis as annualized construction expenditures for new generation facilities in Nevada. We assume that 50 percent of open position expenditures would occur within the state and that 50 percent of open position expenditures would occur outside Nevada.

As shown in Table 17, the construction expenditures are input into REMI as an increase in demand for various sectors in REMI based upon detailed information provided by a federal government agency (NREL 2020). Table 18 lists the relevant REMI sectors for different types of construction projects. Appendix J provides additional information on the data sources and the methodology for allocating expenditures to individual sectors.

Table 18. Allocation of NV Energy Construction Expenditures to REMI Model Sectors

REMI Sectors	New Fossil Generation	New Transmission	Renewable Generation	Renewable Purchases	Open Position	Financing	Repower Valmy	Geothermal	Wind
Construction	28.4%	32.1%	16.1%	16.1%	28.4%	0.0%	26.6%	7.7%	17.6%
Electric power generation, transmission, and distribution	2.5%	0.0%	0.0%	0.0%	2.5%	0.0%	0.0%	0.0%	0.0%
Electrical equipment manufacturing	54.3%	24.9%	43.5%	43.5%	54.3%	0.0%	6.3%	22.9%	3.6%
Industrial machinery manufacturing	9.3%	33.5%	12.9%	12.9%	9.3%	0.0%	52.5%	22.2%	74.9%
Architectural, engineering, and related services	5.6%	9.5%	27.4%	27.4%	5.6%	0.0%	14.6%	47.2%	1.8%
Securities, commodity contracts, and other financial investments and related activities	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	2.0%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Notes: Expenditures on out-of-state facilities are not included. Market purchases are assumed to be out of state; thus, we exclude them from the economic impact analysis.

Sources: NREL 2020 and NERA calculations as explained in text.

b. Fuel Expenditures

Fuel expenditures represent payments for fossil fuels (e.g. natural gas) and their transport to NV Energy's fossil facilities or to the fossil facilities from which NV Energy purchases power. Table 19 shows the annual average fuel expenditures over the period from 2022 to 2051 by category. Table 20 compares the values for the four IRP cases to the Base case. The fuel expenditures are generally lower for the all four IRP cases, due to lower fossil generation. This difference is especially pronounced for the Net-Zero and Geo cases. Appendix J provides information on expenditures by year.

Table 19. Average Annual Fuel Expenditures, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
NVE Existing Generation	**$246**	**$244**	**$237**	**$221**	**$222**
CCs	$235	$234	$228	$211	$210
CTs	$9	$8	$7	$9	$9
Coal	$2	$2	$2	$2	$2
NVE New Generation	**$75**	**$73**	**$78**	**$58**	**$58**
CCs	$64	$63	$60	$55	$55
CTs	$11	$11	$9	$2	$3
Cogen	$0	$0	$0	$0	$0
Solar PV	$0	$0	$0	$0	$0
Battery Storage	$0	$0	$0	$0	$0
Valmy Repower	$0	$0	$9	$0	$0
Power Purchases	**$6**	**$6**	**$6**	**$6**	**$6**
CCs	$1	$1	$1	$1	$1
CTs	$0	$0	$0	$0	$0
Coal	$0	$0	$0	$0	$0
Cogen	$6	$6	$6	$6	$6
Solar PV	$0	$0	$0	$0	$0
Solar Thermal	$0	$0	$0	$0	$0
Battery Storage	$0	$0	$0	$0	$0
Wind	$0	$0	$0	$0	$0
Geothermal	$0	$0	$0	$0	$0
Hydro	$0	$0	$0	$0	$0
Heat Recovery	$0	$0	$0	$0	$0
Landfill Gas	$0	$0	$0	$0	$0
Market	Not incl.	Not incl.	Not incl.	Not incl.	Not incl.
Power Transmission	**$0**	**$0**	**$0**	**$0**	**$0**
Gas Transmission	**$56**	**$56**	**$56**	**$56**	**$56**
Open Position	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$383**	**$380**	**$377**	**$341**	**$342**

Notes: All values are annual averages for the period 2022-2051 in millions of 2022 dollars.
"CCs" denote combined cycle units; "CTs" denote combustion turbine units; "Cogen" denotes cogeneration.
"Not incl." denotes that market purchases are not included as relevant expenditures for the economic impacts analysis because they are assumed to occur outside Nevada.

Source: NERA calculations as explained in text.

Table 20. Average Annual Fuel Expenditures, Relative to the Base Case, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
NVE Existing Generation	**-**	**-$1**	**-$9**	**-$25**	**-$24**
CCs	-	-$1	-$7	-$24	-$24
CTs	-	-$1	-$2	$0	$0
Coal	-	$0	$0	$0	$0
NVE New Generation	**-**	**-$2**	**$3**	**-$17**	**-$16**
CCs	-	-$1	-$3	-$9	-$8
CTs	-	$0	-$2	-$9	-$8
Cogen	-	$0	$0	$0	$0
Solar PV	-	$0	$0	$0	$0
Battery Storage	-	$0	$0	$0	$0
Valmy Repower	-	$0	$9	$0	$0
Power Purchases	**-**	**$0**	**$0**	**$0**	**$0**
CCs	-	$0	$0	$0	$0
CTs	-	$0	$0	$0	$0
Coal	-	$0	$0	$0	$0
Cogen	-	$0	$0	$0	$0
Solar PV	-	$0	$0	$0	$0
Solar Thermal	-	$0	$0	$0	$0
Battery Storage	-	$0	$0	$0	$0
Wind	-	$0	$0	$0	$0
Geothermal	-	$0	$0	$0	$0
Hydro	-	$0	$0	$0	$0
Heat Recovery	-	$0	$0	$0	$0
Landfill Gas	-	$0	$0	$0	$0
Market	Not incl.	Not incl.	Not incl.	Not incl.	Not incl.
Power Transmission	**-**	**$0**	**$0**	**$0**	**$0**
Gas Transmission	**-**	**$0**	**$0**	**$0**	**$0**
Open Position	**-**	**$0**	**$0**	**$0**	**$0**
Total	**-**	**-$3**	**-$6**	**-$42**	**-$41**

Notes: All values are annual averages for the period 2022-2051 in millions of 2022 dollars.
"CCs" denote combined cycle units; "CTs" denote combustion turbine units; "Cogen" denotes cogeneration.
"Not incl." denotes that market purchases are not included as relevant expenditures for the economic impacts analysis because they are assumed to occur outside Nevada.

Source: NERA calculations as explained in text.

Table 21 shows the sources of fuel expenditure estimates as well as our methodology for estimating the economic impacts of fuel expenditures using REMI. There are no fuel expenditures for renewable generation, market purchases (because the generation facilities selling power to NV Energy are assumed to be outside Nevada) or NV Energy's open position (which relates to capacity rather than energy requirements). All fuel expenditure estimates were obtained from NV Energy, as included in the PROMOD modeling results.

Table 21. Economic Impact Methodology for Fuel Expenditures

Category	Expenditures Source	Impacts Methodology in REMI
Existing Generation	NVE	Input as increased demand for oil & gas extraction (for natural gas), mining (for coal) and natural gas transport sectors
New Fossil Generation	NVE	Input as increased demand for oil & gas extraction (for natural gas), mining (for coal) and natural gas transport sectors

Note: We do not include fuel expenditures associated with market purchases of electricity or NV Energy's open position related to its capacity requirements.

c. Non-Fuel O&M Expenditures

Non-fuel O&M expenditures represent payments to operate and maintain generation facilities, including both fixed O&M and variable O&M. NV Energy provided non-fuel O&M expenditure estimates for its existing and new generation facilities. We estimated O&M expenditures for purchases of renewable energy based on EIA's cost parameters (in terms of dollars per megawatt of capacity for fixed O&M and dollars per megawatt-hour of generation for variable O&M) for each type of renewable energy in the latest Annual Energy Outlook (EIA 2021). Table 22 shows the annual average non-fuel O&M expenditures by category for the four IRP cases. Table 23 compares the annual averages of non-fuel O&M expenditures relative to the Base case. The non-fuel O&M expenditures are generally greater in all cases relative to the Base Case. This difference is more pronounced for the Net-Zero and Geo cases. Appendix J provides information on expenditures by year.

Table 22. Average Annual Non-Fuel O&M Expenditures, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
NVE Existing Generation	**$45**	**$45**	**$45**	**$44**	**$44**
CCs	$38	$38	$38	$37	$37
CTs	$6	$6	$6	$6	$6
Coal	$1	$1	$1	$1	$1
NVE New Generation	**$26**	**$32**	**$34**	**$24**	**$25**
CCs	$7	$7	$7	$6	$6
CTs	$14	$14	$13	$5	$5
Cogen	$0	$0	$0	$0	$0
Solar PV	$2	$2	$2	$2	$2
Battery Storage	$2	$9	$8	$10	$11
Valmy Repower	$0	$0	$4	$0	$0
Power Purchases	**$224**	**$224**	**$232**	**$316**	**$296**
CCs	$0	$0	$0	$0	$0
CTs	$0	$0	$0	$0	$0
Coal	$0	$0	$0	$0	$0
Cogen	$0	$0	$0	$0	$0
Solar PV	$97	$97	$99	$118	$121
Solar Thermal	$1	$1	$1	$1	$1
Battery Storage	$96	$96	$102	$134	$139
Wind	$2	$2	$2	$5	$7
Geothermal	$17	$17	$17	$47	$17
Hydro	$11	$11	$11	$11	$11
Heat Recovery	$0	$0	$0	$0	$0
Landfill Gas	$0	$0	$0	$0	$0
Market	Not incl.	Not incl.	Not incl.	Not incl.	Not incl.
Power Transmission	**$0**	**$0**	**$0**	**$0**	**$0**
Gas Transmission	**$0**	**$0**	**$0**	**$0**	**$0**
Open Position	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$295**	**$302**	**$311**	**$384**	**$365**

Notes: All values are annual averages for the period 2022-2051 in millions of 2022 dollars.
"CCs" denote combined cycle units; "CTs" denote combustion turbine units; "Cogen" denotes cogeneration.
"Not incl." denotes that market purchases are not included as relevant expenditures for the economic impacts analysis because they are assumed to occur outside Nevada.

Source: NERA calculations as explained in text.

Table 23. Average Annual Non-Fuel O&M Expenditures, Relative to the Base Case, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
NVE Existing Generation	**-**	**$0**	**-$1**	**-$1**	**-$1**
CCs	-	$0	$0	-$1	-$1
CTs	-	$0	$0	$0	$0
Coal	-	$0	$0	$0	$0
NVE New Generation	**-**	**$6**	**$8**	**-$2**	**-$1**
CCs	-	$0	$0	-$1	-$1
CTs	-	$0	-$1	-$9	-$8
Cogen	-	$0	$0	$0	$0
Solar PV	-	$0	$0	$0	$0
Battery Storage	-	$7	$5	$8	$8
Valmy Repower	-	$0	$4	$0	$0
Power Purchases	**-**	**$0**	**$8**	**$92**	**$72**
CCs	-	$0	$0	$0	$0
CTs	-	$0	$0	$0	$0
Coal	-	$0	$0	$0	$0
Cogen	-	$0	$0	$0	$0
Solar PV	-	$0	$2	$21	$24
Solar Thermal	-	$0	$0	$0	$0
Battery Storage	-	$0	$6	$38	$43
Wind	-	$0	$0	$3	$5
Geothermal	-	$0	$0	$30	$0
Hydro	-	$0	$0	$0	$0
Heat Recovery	-	$0	$0	$0	$0
Landfill Gas	-	$0	$0	$0	$0
Market	Not incl.	Not incl.	Not incl.	Not incl.	Not incl.
Power Transmission	**-**	**$0**	**$0**	**$0**	**$0**
Gas Transmission	**-**	**$0**	**$0**	**$0**	**$0**
Open Position	**-**	**$0**	**$0**	**$0**	**$0**
Total	**-**	**$6**	**$15**	**$89**	**$70**

Note: All values are annual averages for the period 2022-2051 in millions of 2022 dollars.
"CCs" denote combined cycle units; "CTs" denote combustion turbine units; "Cogen" denotes cogeneration.
"Not incl." denotes that market purchases are not included as relevant expenditures for the economic impacts analysis because they are assumed to occur outside Nevada.

Source: NERA calculations as explained in text

Table 24 shows the source of non-fuel O&M expenditure estimates for each category of expenditure in the IRP as well as our methodology for estimating the economic impacts of O&M expenditures using REMI. We assume there are no O&M expenditures related to market purchases (because the generation facilities selling power to NV Energy are assumed to be outside Nevada), NV Energy's open position (related to capacity requirements) and to NV Energy's new transmission facilities.

Table 24. Economic Impacts Methodology for Non-Fuel O&M Expenditures

Category	Expenditures Source	Impacts Methodology in REMI
Existing Generation	NVE	Input as increased demand for repair & maintenance sector
NVE New Generation	NVE (including renewables)	Input as increased demand for repair & maintenance sector
Renewable Purchases	NERA based on EIA and NVE	Input as increased demand for repair & maintenance sector

Note: We assume there are no O&M expenditures associated with market purchases of electricity or NV Energy's open position related to its capacity requirements.

d. Expenditures Excluded from Economic Impacts Analysis

As noted above, several categories of expenditures that contribute toward NV Energy's PWRR are excluded from the economic impacts analysis because they would not necessarily involve future expenditures in Nevada and thus would not necessarily have in-state economic impacts. The largest category of excluded expenditures is market purchases, which we understand would come primarily from out-of-state generation units. Certain smaller expenditures, such as capacity payments to existing generation facilities, lease payments for existing generation and transmission facilities, and natural gas transmission system payments, are also excluded because these types of transactions would not necessarily involve future expenditures with economic impacts in Nevada. Note that these smaller expenditure categories are likely to be nearly constant across the cases, and thus their exclusion is likely not to affect the comparisons among cases. As a result of these exclusions and our use of EIA-based expenditure estimates rather than NV Energy's contract costs for renewable energy purchases, the sum of expenditures in the tables above differs from the PWRR calculated by NV Energy for the cases.

e. Total Expenditures

Table 25 shows the annual average total expenditures for the four IRP cases based upon the cost categories described above. Table 26 compares the annual average expenditures for the other four IRP cases relative to the Base case. All cases have greater expenditures. The Geo case has the greatest expenditures. Appendix J provides information on expenditures by year.

Table 25. Average Annual Total Expenditures, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
Construction	$966	$971	$1,039	$1,301	$1,255
Fuel	$383	$380	$377	$341	$342
O&M	$295	$302	$311	$384	$365
Total	**$1,645**	**$1,653**	**$1,727**	**$2,026**	**$1,963**

Note: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.

Source: NERA calculations as explained in text.

Table 26. Average Annual Total Expenditures, Relative to the Base Case, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
Construction	-	$5	$73	$334	$289
Fuel	-	-$3	-$6	-$42	-$41
O&M	-	$6	$15	$89	$70
Total	**-**	**$8**	**$82**	**$381**	**$319**

Note: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.
Source: NERA calculations as explained in text.

3. Inputs for Negative Economic Impacts

As noted above, greater expenditures on construction, fuel and O&M may ultimately be recovered from electric utility ratepayers in the form of higher electric rates, which lead to increased utility revenue requirements and consumer electricity costs, with the resulting decreases in purchases of non-electricity goods and services on the part of customers and other adverse effects. Exceptions can occur for renewable resources that include federal subsidies. We input these changes in electricity expenditures into REMI as changes in future consumer expenditures on electricity.

NV Energy provided us with projections of retail electricity revenue for Nevada Power and Sierra for the four IRP cases and the Base case over the period from 2022 to 2051. To input these values into REMI, we first apportioned the revenue by customer class. The allocation to customer classes is based on historical revenues. NV Energy provided information that for Nevada Power, electricity revenues are roughly 66 percent from residential customers, 26 percent from commercial customers, and 8 percent from industrial customers. For Sierra, revenues are roughly 37 percent from residential customers, 35 percent from commercial customers, and 28 percent from industrial customers. The differences between the revenue projections for each case relative to the REMI baseline case are then input into REMI as increases in residential, commercial and industrial electricity expenditures.[14]

Table 27 shows the average annual values of electricity revenue requirements over the period from 2022 to 2051 by customer class for the four IRP cases. Table 28 compares annual average electricity revenue for each case relative to the Base case. NV Energy projects annual average electricity customer expenditures to be very similar for the Base, Iron_Hot, and Repower Valmy cases and substantially larger for the Geo and Net-Zero cases. As noted above, larger expenditures on electricity of Nevada residents and businesses will lead to negative economic impacts in REMI. Appendix J provides information on electricity revenue by year.

[14] Specifically, for residential, commercial and industrial customers, we use the REMI variables "Consumer Price (amount) of Electricity," "Electricity (Commercial Sectors) Fuel Cost for All Sectors," and "Electricity (Industrial Sectors) Fuel Cost for All Sectors," respectively.

Table 27. Average Annual Electricity Revenue by Customer Class, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
Residential	$1,050	$1,047	$1,047	$1,087	$1,086
Commercial	$527	$526	$529	$541	$538
Industrial	$248	$248	$252	$252	$249
Total	**$1,826**	**$1,821**	**$1,827**	**$1,880**	**$1,873**

Note: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.
Source: NERA calculations as explained in text.

Table 28. Average Annual Electricity Revenue by Customer Class, Relative to the Base Case, 2022-2051 (2022$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
Residential	-	-3	-3	37	35
Commercial	-	-1	2	14	11
Industrial	-	0	3	4	1
Total	**-**	**-4**	**2**	**55**	**47**

Note: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.
Source: NERA calculations as explained in text.

F. Economic Impacts

This section provides our estimates of the economic impacts of the cases in Nevada based on the data and methodologies discussed above. As noted above, REMI simulations require a "baseline" or reference forecast to which alternative forecasts can be compared. The Base case was prepared specifically by NV Energy to be the baseline scenario. We model changes from this baseline for the four IRP cases but report results relative the Net-Zero case (Preferred Plan).

1. Measures of Nevada Economic Impacts

We report economic impacts for the following REMI model outputs.[15]

- *Gross state product.* The market value of all goods and service produced by labor and property in Nevada.
- *Personal income.* Income received by persons from all sources, including income received from participation in production as well as from government and business transfer payments.

[15] Economic impact output variables definitions are from REMI.

- *Employment.* The number of jobs—full time and part time (counted at equal weight)—including employees, sole proprietors and active partners, but excluding unpaid family workers and volunteers.

In addition, we report estimates of the impacts on state tax revenue. Tax revenue impacts are not standard outputs of REMI, so we use information from the Federation of Tax Administrators ("FTA"). The FTA tracks total state and local tax collections as a percentage of total personal income for all states. For Nevada, in 2018, total state and local tax collections were 10.2 percent of total personal income in the state. Lacking projections, we assume that this percentage remains constant at 10.2 percent throughout the analysis period of 2022 to 2051.

REMI modeling takes as inputs the annual expenditures and electricity revenues relative to the REMI baseline (Base case) in various categories over the period from 2022 to 2051. Appendix J describes the data that are used to develop the sector-specific REMI inputs.

2. Economic Impact Results for Nevada

Table 29 provides our estimates of the economic impacts for selected years in Nevada for the three other resource cases relative to the Net-Zero case (Preferred Plan). Though REMI calculates the impacts relative to the REMI baseline (Base case), we present the economic impact results relative to Net-Zero case for consistency with the presentation of results for the categories of environmental costs. The relative economic impacts of the plans vary over the selected years in Table 29 and over the 30-year period from 2022-2051, reflecting the different timing of construction and other major initial changes in economic activity.

Table 29. Economic Impacts, Relative to the Net-Zero Case

	Nevada Economic Impact Compared to 2019						
	2022	**2023**	**2024**	**2025**	**2035**	**2045**	**2051**
Net-Zero							
Gross State Product (millions of 2022 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2022 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2022 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
Iron_Hot							
Gross State Product (millions of 2022 dollars)	0	0	0	1	-362	-554	-118
Personal Income (millions of 2022 dollars)	0	0	0	-1	-228	-393	-150
State & Local Tax Revenue (millions of 2022 dollars)	0	0	0	0	-23	-40	-15
Employment (total jobs)	0	0	0	4	-3,119	-4,329	-747
Repower Valmy							
Gross State Product (millions of 2022 dollars)	-1	-257	-369	-19	-201	-531	-79
Personal Income (millions of 2022 dollars)	-1	-162	-228	-9	-122	-391	-100
State & Local Tax Revenue (millions of 2022 dollars)	0	-17	-23	-1	-12	-40	-10
Employment (total jobs)	-11	-2,646	-3,719	-134	-1,706	-4,086	-413
Geo							
Gross State Product (millions of 2022 dollars)	0	0	0	0	-25	-40	18
Personal Income (millions of 2022 dollars)	0	0	0	0	-23	-32	32
State & Local Tax Revenue (millions of 2022 dollars)	0	0	0	0	-2	-3	3
Employment (total jobs)	0	0	0	0	-290	-348	195

Notes: The Base case is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs thus are *modeled* for the other three cases in comparison to the Base case. Note that results are *reported* relative to the Net-Zero case. Employment values include full time and part time jobs.

Sources: REMI; NERA calculations as explained in text.

Table 30 provides the averages of the estimates of annual economic impacts in Nevada over the 30-year period from 2022 to 2051 for the other three cases relative to the Net-Zero case (Preferred Plan). Both the Net-Zero and Geo cases have substantially larger average annual economic impacts in Nevada—based upon average annual results for gross state product, personal income, state and local taxes, and employment—than the Iron_Hot and Repower Valmy cases. The Geo case has somewhat larger economic impacts than the Net-Zero case, reflecting larger impacts towards the end of the study period.

Table 30. Average Annual Economic Impacts, Relative to the Net-Zero Case

	Net-Zero	**Iron_Hot**	**Repower Valmy**	**Geo**
Gross State Product (millions of 2022 dollars)	-	-174	-150	30
Personal Income (millions of 2022 dollars)	-	-132	-118	19
State & Local Tax Revenue (millions of 2022 dollars)	-	-13	-12	2
Employment (total jobs)	-	-1,374	-1,172	236

Notes: The Base case is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs thus are *modeled* for the for IRP cases in comparison to the Base case. Note that results are *reported* relative to the Net-Zero case. Employment values include full time and part time jobs.

Sources: REMI; NERA calculations as explained in text.

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IX. Appendix A: Carbon Dioxide Price Scenarios

This appendix provides information on potential national scenarios to regulate carbon dioxide (“CO_2” or “carbon”) from the electric utility sector and NERA’s modeling of three scenarios that would put a “price” on carbon emissions. The carbon price scenarios would affect demand for power generation across fuel types, leading to impacts on fossil fuel prices. This appendix provides estimates of these effects, including an overview of the analysis involved.

Section A discusses the history of proposals to regulate CO_2 emissions from the utility sector under the Clean Air Act and their implications for modeling potential future regulations, including the possibility that future regulations will impose a “price” on utility CO_2 emissions through the flexibility provided by an cap-and-trade approach to implementation. Section B provides a brief background on cap-and-trade programs and proposals to regulate CO_2 emissions that have been implemented or proposed. Section C provides an overview of the three carbon price scenarios we model, which represent different levels of stringency for a cap-and-trade program, the same approach we have used for prior IRPs. We include a fourth scenario that assumes no carbon price is established for utility CO_2 emissions. Section D provides information on the N_{ew}ERA model, the model we use to estimate the impacts of the carbon price scenarios on fuel prices faced by NV Energy. N_{ew}ERA is an economy-wide integrated energy and economic model developed by NERA that includes a bottom-up representation of the U.S. electricity sector. The N_{ew}ERA inputs include baseline projections of natural gas prices obtained from NV Energy, which allows our results to be compatible with other NV Energy analyses. Section E provides the results of our N_{ew}ERA modeling, including estimates of the effects of the carbon price scenarios on natural gas prices and the relevant coal prices as well as information on the utility-sector CO_2 emissions that underlie the three carbon price trajectories.

A. Background on Regulation of Electric Sector Carbon Dioxide Emissions

This section provides background on programs to regulate CO_2 emissions from the electricity sector and the implications for potential future regulations, including the extent to which future regulations will impose a “price” on utility CO_2 emissions. We begin with a brief summary of the advantages of “market-based” policies that would set a price for emissions.

1. Cost-Saving Advantages of Market-Based Policies

“Market-based” policies would reduce carbon emissions by putting a “price” on carbon emissions, either directly through a carbon tax or indirectly through creating a market for tradable emissions rights within the limits of a “cap” on total emissions (the emissions rights in such “cap-and-trade” programs are also called “allowances” or “permits”) (Harrison 2011). In contrast to other policy approaches—including mandates for particular technologies—putting a price on carbon emissions has the economic advantage of reducing the overall cost of meeting a target level of GHG emissions because it provides incentives for firms and households to undertake the cheapest options across a wide range of potential abatement measures. The cost of reducing GHG emissions can vary greatly for different economic agents and market-based policies give regulated entities flexibility to find and apply the lowest-cost methods for reducing emissions, minimizing the costs of meeting emission reduction targets (Harrison 2011).

2. History of Regulations on Electric Sector Carbon Dioxide Emissions

On October 23, 2015, the U.S. Environmental Protection Agency ("EPA") published the final Clean Power Plan ("CPP") rule to regulate CO_2 emissions from existing fossil fuel-fired power plants under Section 111(d) of the Clean Air Act. The rule set GHG reduction targets by state and allowed for states to develop various policy instruments to meet these targets, including emissions trading programs that would allow companies to buy and sell allowances, i.e. the right to emit a ton of CO_2. The cap-and-trade approach has the well-known advantage of minimizing the cost of meeting a given emission reduction target and, as discussed below, has been implemented to control utility emissions in various jurisdictions, including Northeast states and California. In response to litigation challenging EPA's promulgation of the CPP, on February 9, 2016, the Supreme Court "stayed" implementation of the CPP.

On March 28, 2017, President Donald Trump signed the Executive Order on Energy Independence (E.O. 13783), which (among other provisions) called for a review of the CPP. On October 16, 2017, EPA formally proposed to repeal the CPP after completing its review (EPA 2017). On August 21, 2018, EPA proposed a new rule to reduce greenhouse gas emissions from power plants entitled the Affordable Clean Energy ("ACE") rule, to replace the CPP. The ACE Rule, which was finalized on July 8, 2019, provides guidelines for states to develop emission standards for existing electricity generation units, with no provision for a potential national cap-and-trade program for GHG emissions from power plants (EPA 2019). In 2019, a number of groups filed lawsuits challenging the lawfulness of the ACE rule (NYU 2020).

3. Potential Future Regulations on Electric Sector Carbon Dioxide Emissions

The Biden administration has indicated its intention not to defend the ACE Rule from litigation (ALA v. EPA 2021) and in January 2021, the U.S. Court of Appeals vacated the rule. But the Biden administration has not announced any proposal to replace the ACE Rule with another program to implement Section 111(d) of the Clean Air Act for electric utility emissions. There are some indications, however, that the Biden administration would favor the flexibility of an emissions trading approach. As one indication, President Biden's *American Jobs Plan*, announced March 31, 2021 includes an Energy Efficiency and Clean Electricity Standard (EECES) to achieve 100 percent clean power by 2035, including nuclear and hydropower as "clean" sources of electricity (WH 2021). Moreover, the House Energy and Commerce Committee Democrats recently introduced the CLEAN Future Act, which would establish similar emission reduction goals with a federal clean electricity standard (CES) that would require retail sellers of electricity to ensure that 100 percent of their sales are from zero-emitting generation resources by 2035. The proposal includes a provision providing for the flexibility to trade zero-emission credits before the final deadline; such flexibility could be included in any implementation of EECES (HR 2021). These developments thus suggest that a future regulation to reduce CO_2 emissions from the utility sector would include the cost-saving flexibility of a cap-and-trade approach.

B. Background on Prior Carbon Cap-and-Trade Programs and Proposals

This section includes brief summaries of the major programs and proposals to use a cap-and-trade program to regulate carbon emissions.

- *European Union Emissions Trading Scheme ("EU ETS")*. The EU ETS was launched in 2005 and regulates large sources of GHG emissions—including power stations, factories and other sources—in 31 countries, including all European Union member states as well as Iceland, Norway and Lichtenstein. The system was implemented in different phases from the initial 2005-2007 pilot phase to Phase IV, which started in January 2021 and will end in December 2028. Over time, the EU ETS been changed to provide for different caps, to include GHG emissions other than carbon, and to extend the program to other emission sources (Schmalensee 2017).

- *Regional Greenhouse Gas Initiative ("RGGI")*. The RGGI program currently comprises ten northeastern U.S. states and covers CO2 emissions from the power sector. Taking effect in 2009, RGGI was the first cap-and-trade program in the United States to deal with GHG emissions (Schmalensee 2017).

- *California Assembly Bill ("AB") 32*. California AB-32 includes various programs to reduce GHG emissions in California, including a cap-and-trade program that began in 2013. The California cap-and-trade program covers GHG emissions from electricity sold in the state (whether produced in-state or imported), from large manufacturing facilities, and from fuels, thereby covering 85 percent of the state's emissions (Schmalensee 2017).

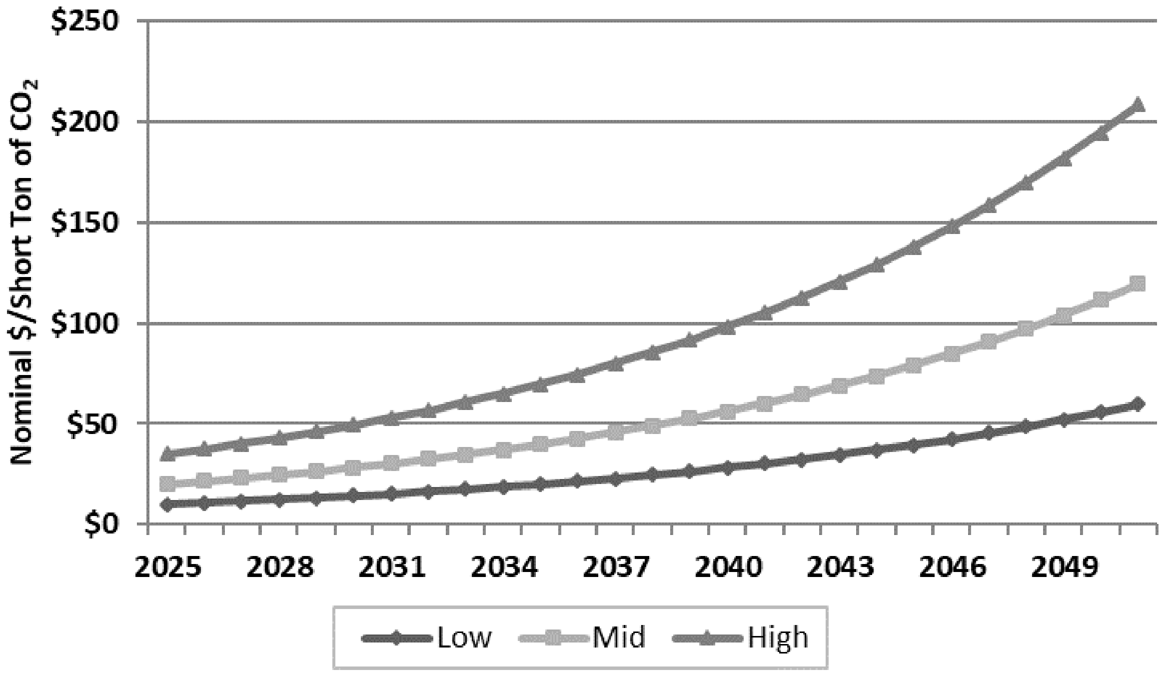
- *National legislative proposals*. In June 2009, the U.S. House of Representatives passed an economy-wide cap-and-trade program for greenhouse gas ("GHG") emissions, commonly referred to as the "Waxman-Markey Bill" (U.S. House of Representatives 2009), which set goals of reducing economy-wide GHG emissions by 17 percent below 2005 levels by 2020 and 83 percent below 2005 levels by 2050 (HR 2009). Senators John Kerry and Joe Lieberman proposed a similar bill in the U.S. Senate in 2010, but it did not proceed to a vote in the full Senate. Both programs would have established total annual limits on GHG emissions from regulated sources, including GHG emissions from the electricity sectors.

C. Electricity Sector CO_2 Price Scenarios

To account for the varying degrees of potential stringency in future regulations on carbon emissions from the electricity sector, NERA developed three CO_2 allowance price scenarios that would result from three different emission caps on emissions from the electricity sector. Figure A-

1 shows the price trajectories for the Low, Mid, and High CO_2 Price scenarios in nominal dollars per metric ton of CO_2.

Figure A-1. CO_2 Allowance Prices (Nominal$ per Metric Ton of CO_2)



Source: NERA assumptions as explained in text.

The scenario used to develop results for environmental costs and economic impacts in this report is the "Mid CO_2 Price" scenario, in which a national cap-and-trade program for the electricity sector is assumed to be put in place, with a cap consistent with allowance prices assumed to begin in 2025 at $20 per metric ton (2020$) and increase each year at a 5 percent real rate. NERA also developed results for a "Low CO_2 Price" scenario and a "High CO_2 Price" scenario, in which the CO_2 price is assumed to begin in 2025 at $10 per metric ton (2020$) and $35 per metric ton (2020$), respectively, and increase each year at the same real interest rate. Prices have been converted from 2020 dollars to nominal dollars using inflation information provided NV Energy.

D. Methodology for Modeling Effects of CO_2 Price Scenarios on Fuel Prices

The three CO_2 policy scenarios would have differential effects on demand for power generation across fuel types, leading to impacts on fuel prices and CO_2 emissions in the electricity sector. These impacts are based upon modeling using the N_{ew}ERA model, an economy-wide integrated energy and economic model that includes a bottom-up representation of the U.S. electricity sector. The sections below provide an overview of the N_{ew}ERA model, information used in the calibration of modeling inputs, and the methodology for estimating fuel price impacts within the model. Additional information on the N_{ew}ERA model is provided in Appendix B.

1. Overview of NewERA Model

NERA developed the NewERA model to project the impact of policy, regulatory, and economic factors on the energy sectors and the economy. The NewERA model combines a macroeconomic model that includes all sectors of the economy with a detailed electric sector model that represents electricity production. The electric sector model (the model used for this analysis) is a detailed model of the electric and coal sectors. Each of the more than 17,000 electric generating units in the United States is represented in the model. The model minimizes costs while meeting all specified constraints, such as demand, peak demand, emissions limits, and transmission limits. The model determines optimal investments to undertake and units to dispatch. When the electric sector model is integrated with the macroeconomic model of the entire U.S. economy, electricity demand can respond to changes in prices and supplies.

2. Calibration of NewERA Model

The NewERA model was calibrated based on information from NV Energy as well as from the U.S. Energy Information Administration ("EIA") and other sources. The following is a summary of the inputs and assumptions used to calibrate the baseline model.

a. Energy Market Inputs in NewERA Baseline

The following are the key energy market inputs in the NewERA baseline.

- *Fossil Fuel Prices.* NV Energy provided NERA with a Henry Hub natural gas price trajectory through 2051 (in nominal $/MMBtu). NERA employed the GDP chain-type price indices released as part of AEO 2021 to convert these gas prices to constant 2010 dollars which were then inputted into the NewERA electricity model.

- *Electricity Demand.* NERA updated electricity demand, including peak demand, based upon AEO 2019 Reference Case projections.

- *State Electricity RPS.* State RPS requirements were updated based on a September 2020 analysis by the Lawrence Berkeley National Laboratory.

- *Electricity Sector Costs*. NERA updated costs of new electricity sector technologies (capital costs, fixed O&M, and variable O&M costs) to reflect AEO 2021 projections.

- *Existing Generators.* NERA updated the inventory of existing generators by both removing units that have retired since the last model update and by including information on recently announced retirements of coal and nuclear generators. Similarly, NERA added new generating capacity put in place since the last model update and included information on planned new generating capacity already under construction.

- *Coal Supply.* NERA updated coal supply curves in the electricity sector model to more accurately reflect current market conditions for coal prices.

- *Technology Build Timing.* NERA adjusted the timing parameters of new units to reflect technology-specific information on expected construction timing.

b. Energy and Environmental Policies in the N$_{ew}$ERA Baseline

The baseline in the N$_{ew}$ERA model used for this analysis includes all major energy and environmental policies and regulations in effect as of May 2021.[16] These include federal policies and regulations, such as the Mercury and Air Toxics Standards (MATS) and the Cross State Air Pollution Rule (CSAPR), as well as state and regional policies and regulations including state RPS, California's cap-and-trade program, and RGGI.

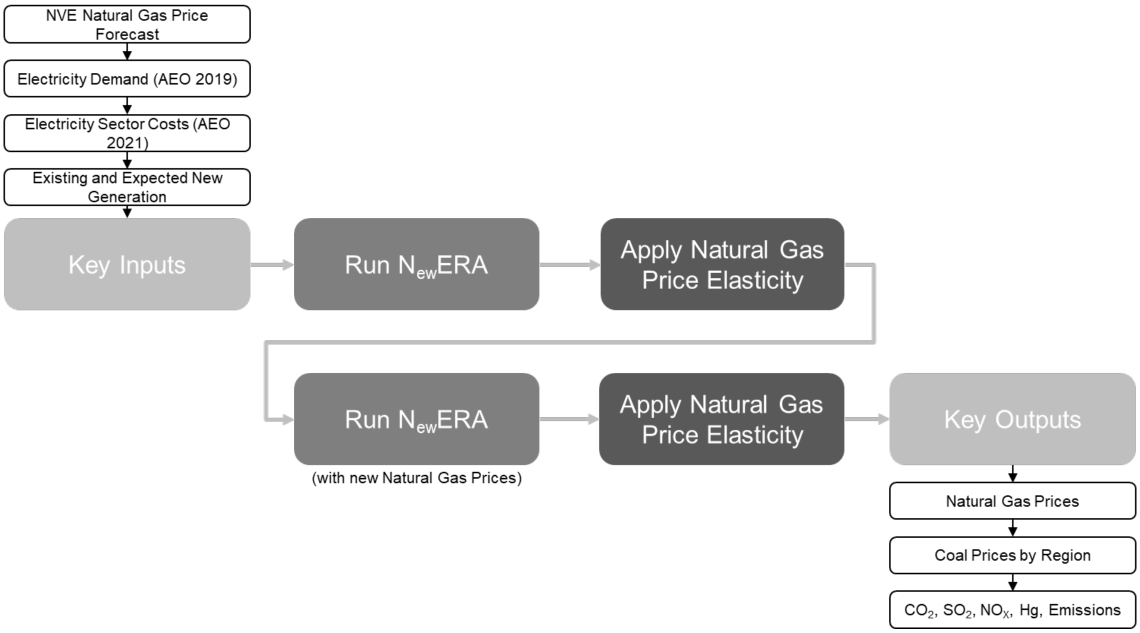
3. Methodology for Estimating Fuel Price Impacts and Emissions

The N$_{ew}$ERA model was run for each of the three CO_2 Price scenarios identified in Section B above. The alternative CO_2 price trajectories affect the relative demand for energy by fuel type. A higher CO_2 price will reduce demand for energy of high-carbon generators (e.g., coal power plants) and will increase demand for energy of low-carbon generators (e.g., renewables). These changes in demand lead to changes in fossil fuel prices.

Figure A-2 provides a visual summary of the methodology we used to estimate fuel price impacts of alternative CO_2 price scenarios using N$_{ew}$ERA.

[16] The model also includes state Renewable Portfolio Standards, which are up to date as of July 2017 per an analysis by the Lawrence Berkeley National Laboratory.

Figure A-2: Overview of Major NewERA Modeling Steps



Note: The "Key Inputs" and "Key Outputs" reflect the items that relate specifically to the modeling done for this analysis. See Appendix B for a more detailed overview of the N_{ew}ERA model.

The methodology includes a two-stage modeling approach to account for effects of changes in natural gas prices on non-electric natural gas demand. Specifically, we start with initial model runs that provide the electricity sector natural gas demand for each scenario. This sector-specific demand is added to Annual Energy Outlook ("AEO") 2021 Reference Case non-electric sector natural gas demand (inclusive of net exports of natural gas) to calculate the projected total U.S. natural gas supply.[17] We then calculated the percentage change in total U.S. natural gas supply for each modeled year in each CO_2 policy scenario, relative to the same modeled year in the baseline scenario (No CO_2 Price). Using an average price elasticity of supply for natural gas obtained from EPA's Integrated Planning Model,[18] we calculate an implied percentage change in the Henry Hub natural gas price for each modeled year for each scenario. These updated Henry Hub natural gas prices were then used as inputs in the second model run, which results in the outputs that are used in our report, including fuel price and emissions trajectories.

[17] Since the model horizon goes out to 2051 while the AEO projections only go out to 2050, a compound annual growth rate from 2040 through 2050 based on natural gas demand projections from the AEO was used to estimate total U.S. natural gas supply in the 2051 model year.

[18] We calculate an average supply elasticity of 1.2 from the supply curves depicted in Figure 8.16 and the supporting information in Table 8-4 of the model documentation, available at https://www.epa.gov/airmarkets/documentation-ipm-platform-v6-all-chapters (US EPA 2018).

Note also that for computational simplification over the 30-year period, the model generates estimates for every third year in the study period (in this case, 2022, 2025, 2028, etc.). Estimates for the intermediate years are interpolated.

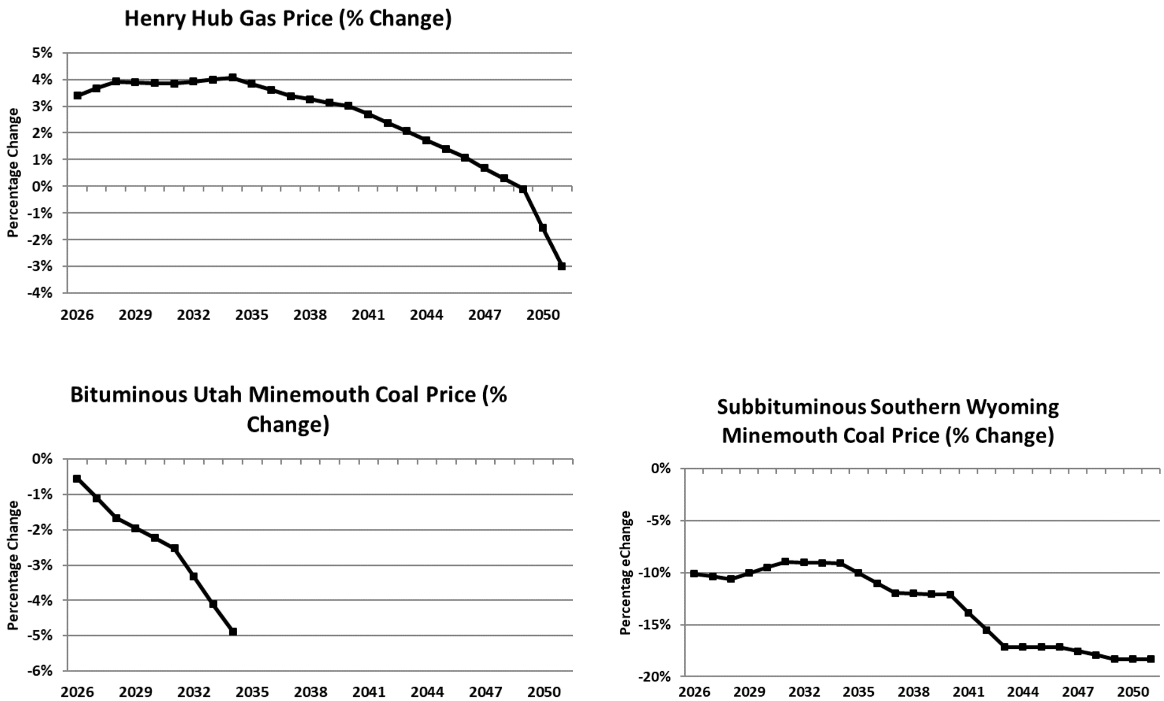
E. Modeling Results

This section includes the modeling results, including the effects of the three CO_2 price scenarios on fossil fuel prices (as measured by percentage changes from the baseline, which assumes no carbon price) and the CO_2 emissions trajectories consistent with the carbon price trajectories.

1. Fuel Price Impacts

The three panels of Figure A-3 show our estimates of the percentage differences in wholesale fossil fuel price projections relative to the no carbon price scenario. These prices are net of any costs to cover the CO_2 emissions. As expected, coal prices are generally lower under the Mid CO_2 Price scenario as a result of decreased demand for fossil fuels. Natural gas prices increase in the near- to medium-term under the Mid CO_2 Price scenario as some of the demand for coal shifts to natural gas in addition to renewables. As the CO_2 price becomes sufficiently high, demand for natural gas begins to decrease as generation shifts more completely towards renewables.

Figure A-3. Percent Change in Wholesale Fossil Fuel Prices for the Mid CO_2 Price Scenario Relative to the No CO_2 Price Scenario

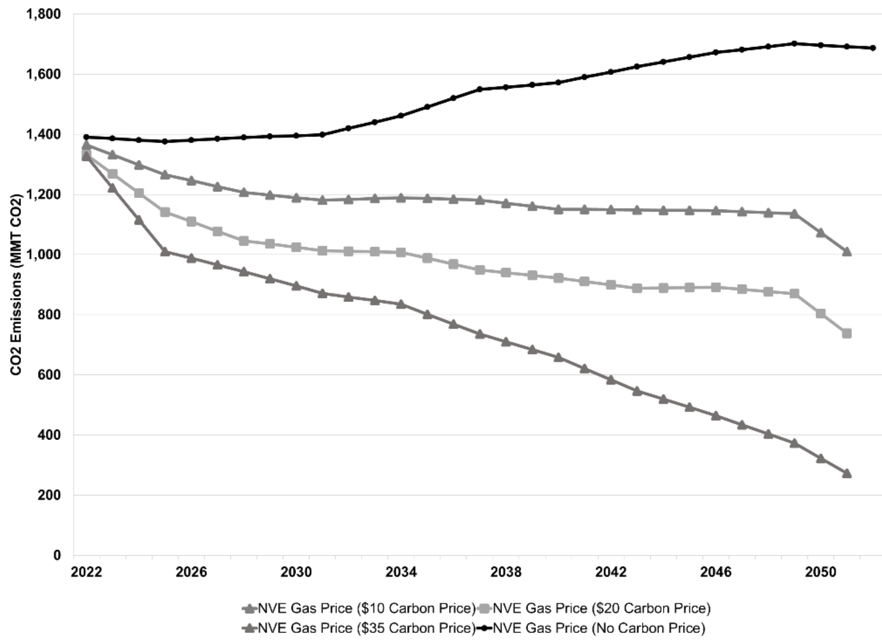


Source: NERA calculations as explained in text.

2. CO_2 Emissions

Figure A-4 shows the electricity sector CO_2 emission trajectories that are consistent with the baseline and the three CO_2 price scenarios.

Figure A-4. CO_2 Emissions (MMT CO_2)



Source: NERA calculations as explained in text.

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X. Appendix B: Overview of the N_{ew}ERA Model

This appendix provides details on N_{ew}ERA, the model we used to develop the carbon price scenarios and fuel price projections described in Appendix A.

Section A provides a general overview of the modeling framework used in N_{ew}ERA, which integrates a bottom-up representation of the U.S. electricity sector with a top-down representation of the production, consumption, and investment decisions across the rest of the U.S. economy.

Section B provides additional details on the electric sector model.

A. Modeling Framework

NERA developed the N_{ew}ERA model to forecast the impact of policy, regulatory, and economic factors on the energy sectors and the economy. When evaluating policies that have significant impacts on the entire economy, this model specification captures the effects as they ripple through all sectors of the economy and the associated feedback effects.

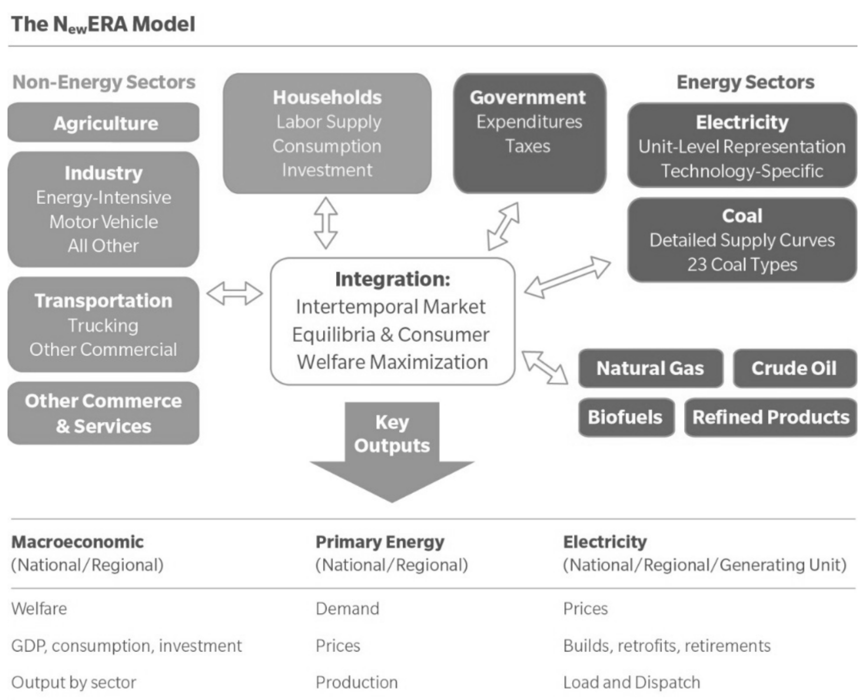
The N_{ew}ERA model combines a macroeconomic model with all sectors of the economy with a detailed electric sector model that represents electricity production. This coupling allows for a comprehensive understanding of the direct and indirect policy impacts to all aspects of the economy, including the complex interdependencies between energy consumption, electricity supply, and macroeconomic growth. The main benefit of the integrated framework is that the electric sector can be modeled in great detail and yet, through integration, the model captures the interactions and feedbacks between all sectors of the economy. That is, electric technologies can be well represented according to engineering specifications. The integrated modeling approach also provides consistent price responses since all sectors of the economy are modeled. In addition, under this framework we are able to model electricity demand response. Additional information on the two components of the model is provided below.

- The macroeconomic model incorporates all production sectors except electricity and final demand of the economy. Policy consequences are transmitted throughout the economy as sectors respond until the economy reaches equilibrium. The production and consumption functions employed in the model enable gradual substitution of inputs in response to relative price changes, thus avoiding all-or-nothing solutions.
- The electric sector model is a detailed model of the electric and coal sectors. Each of the more than 17,000 electric generating units in the United States is represented in the model. The model minimizes costs while meeting all specified constraints, such as demand, peak demand, emissions limits, and transmission limits. The model determines investments to undertake and unit dispatch. Because the N_{ew}ERA model is an integrated model of the entire U.S. economy, electricity demand can respond to changes in prices and supplies. The N_{ew}ERA model also represents the domestic and international crude oil and refined petroleum markets.

The NewERA model outputs include demand and supply of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include gross regional product, consumption, investment, and changes in "job equivalents" based on labor wage income, as discussed below in the section on macroeconomic modeling.

Figure B-1 provides a simplified representation of the key elements of the NewERA modeling system.

Figure B-1. NewERA Modeling System Representation



B. Electric Sector Model

The electric sector model that is part of the NewERA modeling system is a bottom-up model of the electric and coal sectors. Consistent with the macroeconomic model, the electric sector model is fully dynamic and includes perfect foresight (under the assumption that future conditions are known). Thus, all decisions within the model are based on minimizing the present value of costs over the entire time horizon of the model while meeting all specified constraints, including demand, peak demand, emissions limits, transmission limits, RPS regulations, fuel availability and costs, and new build limits. The model set-up is intended to mimic (as much as is possible within a model) the approach that electric sector investors use to make decisions. In determining the least-cost method of satisfying all these constraints, the model endogenously decides:

- What investments to undertake (*e.g.,* addition of retrofits, build new capacity, repower unit, add fuel switching capacity, or retire units);

- How to operate each modeled unit (*e.g.,* when and how much to operate units, which fuels to burn) and what is the optimal generation mix; and

- How demand will respond. The model thus assesses the trade-offs between the amount of demand-side management ("DSM") to undertake and the level of electricity usage.

Each unit in the model has certain actions that it can undertake. For example, all units can retire, and many can undergo retrofits. Any publicly announced actions, such as planned retirements, planned retrofits (for existing units), or new units under construction can be specified. Coal units have more potential actions than other types of units. These include retrofits to reduce emissions of SO_2, NO_X, mercury, and CO_2.[19] The costs, timing, and necessity of retrofits may be specified as scenario inputs or left for the model to endogenously select. Coal units can also switch the type of coal that they burn (with practical unit-specific limitations). Finally, coal units may retire if none of the above actions will allow them to remain profitable, after accounting for their revenues from generation and capacity services.

Most of the coal units' actions would be in response to environmental limits that can be added to the model. These include emission caps (for SO_2, NO_X, mercury, and CO_2) that can be applied at the national, regional, state or unit level. We can also specify allowance prices for emissions, emission rates (especially for toxics such as mercury) or heat rate levels that must be met.

Just as with investment decisions, the operation of each unit in a given year depends on the policies in place (*e.g.*, unit-level standards), electricity demand, and operating costs, especially energy prices. The model accounts for all these conditions in deciding when and how much to operate each unit. The model also considers system-wide operational issues such as environmental regulations, limits on the share of generation from intermittent resources, transmission limits, and operational reserve margin requirements in addition to annual reserve margin constraints.

To meet increasing electricity demand and reserve margin requirements over time, the electric sector must build new generating capacity. Future environmental regulations and forecasted energy prices influence which technologies to build and where. For example, if a national RPS policy is to take effect, some share of new generating capacity will need to come from renewable power. On the other hand, if there is a policy to address emissions, it might elicit a response to retrofit existing fossil-fired units with pollution control technology or enhance existing coal-fired units to burn different types of coals, biomass, or natural gas. Policies calling for improved heat rates may lead to capital expenditure spent on repowering existing units. All of these policies will also likely affect retirement decisions. The N_{ew}ERA electric sector model endogenously captures all of these different types of decisions.

The model contains 64 U.S. electricity regions (and 11 Canadian electricity regions). Figure B-2 shows the U.S. electricity regions.

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[19] As discussed in the report body, N_{ew}ERA does not incorporate EPA's recently proposed power sector CO_2 rule.

Figure B-2. NewERA Electric Sector Model – U.S. Regions

The electric sector model is fully flexible in the model horizon and the years for which it solves. When used in an integrated manner with the macroeconomic model, and to analyze long-term effects, the model has the same time steps as in the macroeconomic model.

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XI. Appendix C: Potential Carbon Dioxide Allowance Allocations

This appendix describes our methodology for estimating the quantity and value of CO_2 allowances that might be allocated to Nevada Power and Sierra if a national electricity sector program providing for the flexibility of a national cap-and-trade program were implemented. Note that such a program might include state involvement, including state involvement in determining allocations (as was done in some prior programs).

A. Overview of Methodology

The major steps in our methodology are as follows.

1. Develop projections of total electricity sector emissions, which represent the total emission budgets over time under a potential national electricity sector cap-and-trade program.

2. Review precedents for initial allocations in major national cap-and-trade programs and proposals, focusing on the EU ETS, the major national legislative proposals in the U.S., and the two U.S. state/regional programs (AB 32 program in California and RGGI program in the Northeast US).

3. Develop judgements for the two major elements of the initial allocation: (a) fractions of the capped allowances over time that would be allocated "for free" (versus auctioned); and (b) criteria that would be used to distribute the "free" allowances to electric companies such as Nevada Power and Sierra.

4. Based on judgements in Step 3 related to (a), develop estimates of the fractions of allowances that would be allocated "for free" in each year from 2025-2051.

5. Based on judgements in Step 3 related to (b) and the relevant data for U.S. electricity companies, develop estimates of shares of the "free" total in each year that would be allocated to Nevada Power and Sierra from 2025-2051.

6. Based on results of Steps 1, 4 and 5, develop estimates of the numbers of free allowances Nevada Power and Sierra's allowances would receive in each year from 2025-2051.

7. Use estimates of allowance prices under the Mid CO_2 Price scenario to develop estimates of the dollar value of the allowances provided to Nevada Power and Sierra in each year from 2025-2051.

8. Use relevant nominal discount rates for Nevada Power and Sierra to calculate the present value of the dollar value of the allowances provided to Nevada Power and Sierra as of 2021.

The remainder of this appendix is organized as follows. Section B reviews precedents for initial allocations (Step 2) and summarizes our judgements for the fractions of free allowances that would be provided over time and the criteria that would be used to distribute free allowances to electric utility companies such as Nevada Power and Sierra (Step 3). Section C provides the empirical information we use to estimate the quantity and value of CO_2 allowances that Nevada Power and Sierra might receive under these assumptions (Steps 1, 4, 5, 6, 7, and 8).

B. Judgements on Potential Free CO_2 Allowance Allocations

This section provides the judgments that are made on (a) the fractions of the expected allowances over time that would be allocated "for free" (versus auctioned); and (b) the criteria that would be used to distribute the "free" allowances to electricity companies such as Nevada Power and Sierra.

1. Percentages of Free Allocations

Precedents in prior cap-and-trade programs and proposals provide useful background for judgments on the fraction of allowances that would be allocated for free and how that fraction would change over time. The general pattern has been to provide a large fraction of free allowances in the early years of a program—in order to mitigate adverse effects on program participants—and to transition to zero free allowances (and 100 percent auctioning) over time, although there are some exceptions.

a. Free Allocations in Prior Major Prior Cap-and-Trade Programs and Proposals

This section provides brief summaries of the fraction of free allowances in major prior cap-and-trade programs. Note that these programs differ in many components—including details of the initial allocation—and these summaries provide only basic overviews.

i. Free Allocations in EU ETS

The European Union Emissions Trading Scheme ("EU ETS") is a European economy-wide cap-and-trade program for greenhouse gas emissions that was begun in 2005 (EU Commission 2003). In the first two phases of the EU ETS (2005-2012)—the first of which was a pilot phase—allocations were determined by the individual EU countries. The program required that at least 95 percent of allowances be allocated to participants for free in the first (pilot) phase (2005-2007) and that 90 percent be allocated for free in the second phase (2008-2012) (Ellerman 2015, p. 92). Allocation was harmonized across the European Union starting in the third phase (2013-2020) and free allocation was phased out for the various participating sectors, with free allocation to be completely phased out by 2027. The principal criterion for providing free allocations to sectors was to avoid adverse effects on the competitiveness of European companies, as competitors in other countries did not have similar programs. Because the electric generators were deemed not to face competitive threat from outside the European Union, free allocation ended for electric generators starting in 2013 (with exceptions allowed until 2020 for particularly coal-dependent EU countries) (Ellerman 2015, p. 92).

ii. Free Allocations in Waxman-Markley Proposal

The American Clean Energy and Security Act was introduced in the House of Representatives on May 15, 2009 by Representatives Henry A. Waxman and Edward Markley ("Waxman-Markley bill") (HR 2009). The Waxman-Markey bill provided for economy-wide emissions caps starting in 2012 that would reduce overall emissions by 17 percent relative to 2005 levels. The Waxman-Markey bill called for allocating about 82 percent of allowances for free from 2012 to 2018, gradually diminishing to 30 percent by 2030 (COB 2009). Electricity local distribution companies ("LDCs") were to be allocated 44 percent of the total allowance allocation, with conditions that the allowances be used to reduce impacts on electricity consumers (HR 2009, Section 782). Coal-fired generators and others with long-term power purchase agreements received 5 percent of the total allocation.

iii. Free Allocations in Kerry-Liebermann Proposal

On May 13, 2010, Senators John Kerry and Joe Lieberman unveiled the draft American Power Act ("Kerry-Lieberman bill") similar to the Waxman-Markey bill (HR 2010). The Kerry-Lieberman bill provided for a similar level of initial free allocation (77 to 81 percent) as in the Waxman-Markley bill, with the percentage decreasing to 25 percent by 2030. The Kerry-Lieberman bill provided similar allocations to individual sectors as the Waxman-Markey bill, including 51 percent to LDCs [and 5 percent to generators with long-term power purchase agreements] (HR 2010, Section 721).

iv. Free Allocations in California AB-32

In 2006, the California Legislature approved Assembly Bill 32 ("AB32"), which established the State's 2020 GHG emission reduction target, required the California Air Resources Board ("CARB") to adopt a plan to achieve the target and authorized CARB to include a cap-and-trade program as a carbon pricing mechanism. The multi-sector cap-and-trade program that was developed by CARB called for 49 percent of allowances to be allocated for free in the early years of the program, with electricity companies receiving some of the free allocations (CARB 2010a).

v. Free Allocations in RGGI

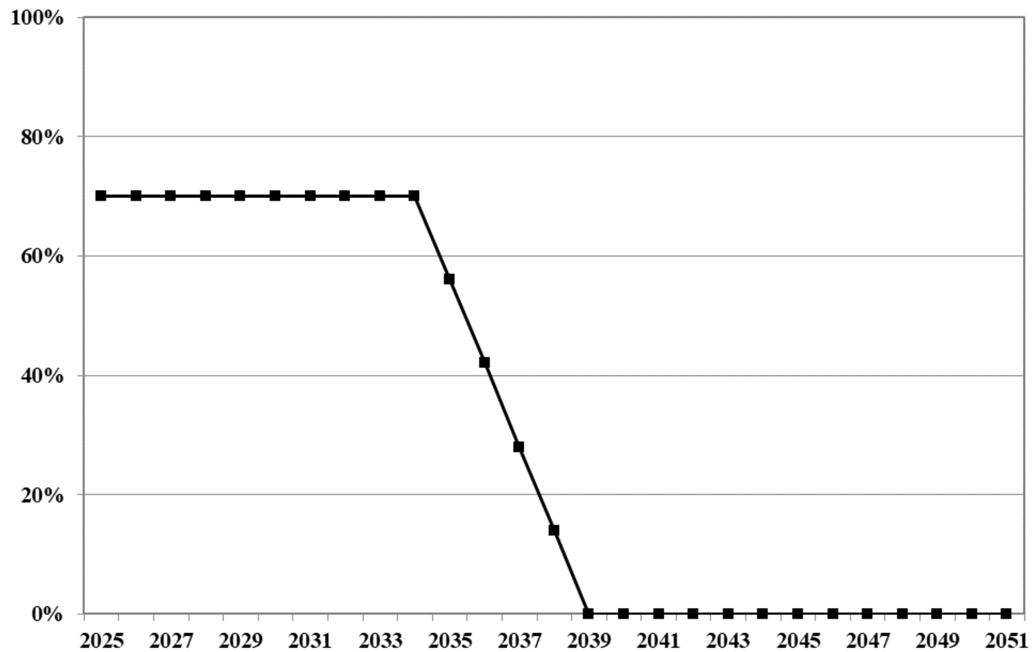
In December 2005, Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont signed a Memorandum of Understanding, outlining a regulatory framework for the development of a regional cap-and-trade program knows as the Regional Greenhous Gas Initiative

("RGGI") (RGGI 2005).[20] The program covers GHG emissions from fossil fuel-fired electricity generating companies and started in 2009. Although allocations are determined separately for the participating states—which has changed somewhat over time—RGGI states auction more of 90 percent of allowances, meaning that less than 10 percent of allowances are allocated for free. Revenues from the auctions are used for energy efficiency as well as for general state expenditures (RGGI 2009).

b. Assumptions on Free Allocation for 2021 IRP

Based on the background on these prior programs and proposals, we assume that electricity companies such as Nevada Power and Sierra would receive 70 percent of the total annual allocation for ten years (from the beginning of the program in 2025 until 2034) and then the free allocation would decline linearly to zero by 2039. The resulting free allocation percentage trajectory is shown below in Figure C-1. These percentages are relative to the assumed national caps on electricity sector emissions over time in each of the three CO_2 price scenarios.

Figure C-1. Free Allocation as a Percentage of Annual Emission Cap Under Potential Electric Sector Cap and Trade Program



Sources: NERA calculations as explained in text.

[20] Massachusetts, Rhode Island and Maryland participate in the program since 2007. New Jersey withdrew from the program in 2012 but resumed in 2020. Virginia began participation in 2021.

2. Criteria for Allocating Free Allowance to Electricity Companies

Various criteria could be used to allocate allowances to individual companies, such as CO_2 emissions or sales, including “benchmarks” for the carbon intensity. Moreover, the criteria could be based on historical information (“grandfathering”) or could be modified over time to reflect new information (“updated”).

a. Methods of Allocating Free Allowances in Major Programs and Proposals

This section provides brief overviews of the method of allocating free allowances in the same major programs and proposals as in the prior section.

i. Allocations in EU ETS

In a review of the first years of the program, the EU Commission noted that “[by] far the largest share of allowances has been allocated on the basis of "grandfathering,”, which means allocating allowances on the basis of historical emissions” (EU Commission 2008).

ii. Allocations in Waxman-Markley Bill

The Waxman-Markley proposal called for the LDC allocation to be distributed to individual electricity companies based on two criteria: (1) companies’ shares of the U.S. electricity sector’s CO_2 emissions during a historical three-year period; and (2) companies’ shares of the U.S. electricity sector’s annual sales during the cap-and-trade program. Under Waxman-Markey, the two criteria would have equal weight (i.e., allocation to individual companies in a given year would be based 50 percent on their shares of historical emissions and 50 percent on their shares of annual sales updated every three years) (HR 2009, Section 783).

iii. Allocations in Kerry-Lieberman Bill

Under Kerry-Lieberman, allocation to individual companies in a given year would be based 75 percent on their shares of historical emissions and 25 percent on their shares of annual sales updated every three years (HR 2010, Section 782).

iv. Allocations in California AB-32

The number of allowances allocated to each EDUs under the California AB-32 program is based on its anticipated cap-and-trade program compliance costs, which are forecasted based upon estimates of generation by fuel type and the relevant fuel carbon dioxide emission rates (CARB 2010b). This method is similar to basing allocations on future carbon dioxide emissions. Note that although the allocations are based upon future values, the values are determined “ex ante” rather than a “ex post” future values. Thus, the allocations are determined at the beginning of the program rather than “updated” as the program is implemented.

b. Assumptions for 2021 IRP

Based upon these various precedents, we use two criteria: (a) historical carbon dioxide emissions; and (b) future electricity sales. These are factors included in both the Waxman-Markey bill and the Kerry-Lieberman bill, and similar to those used in the other programs. We use the fractions in the Kerry-Lieberman bill—75 percent based on historical emissions and 25 percent based on projected future sales.

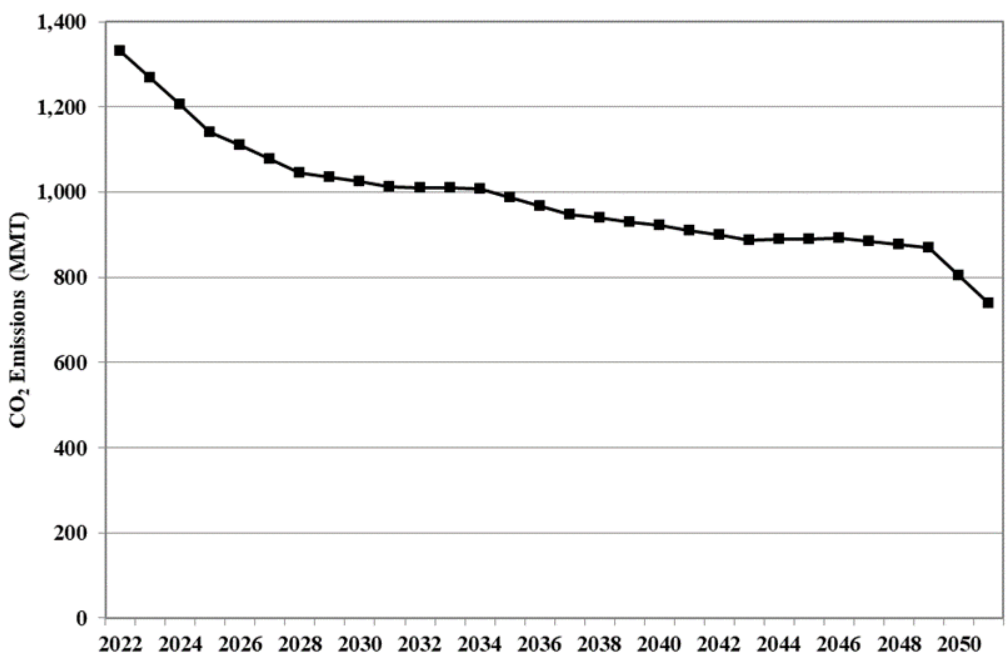
C. Calculations of Potential Value of Free Allowance Allocations to Nevada Power and Sierra

This section summarizes the steps we used to develop estimates of the values of free allowances that might be provided to Nevada Power and Sierra under a potential electric sector cap-and-trade program.

1. Total Emissions Budget

The total national emission budget in a given year under the potential cap and trade program is set at the estimated total amount of emissions under a CO_2 prices assumed in our cap-and-trade modeling. We estimate the total cap size based upon the estimates of electricity sector CO_2 emissions developed in our N$_{ew}$ERA model. Figure C-2 shows the total electricity sector emissions under the presumed cap-and-trade program under the Mid CO_2 Price scenario.

Figure C-2. Total Electricity Sector Emissions under Cap-and-Trade Program, Mid CO_2 Price Scenario (MMT CO_2)

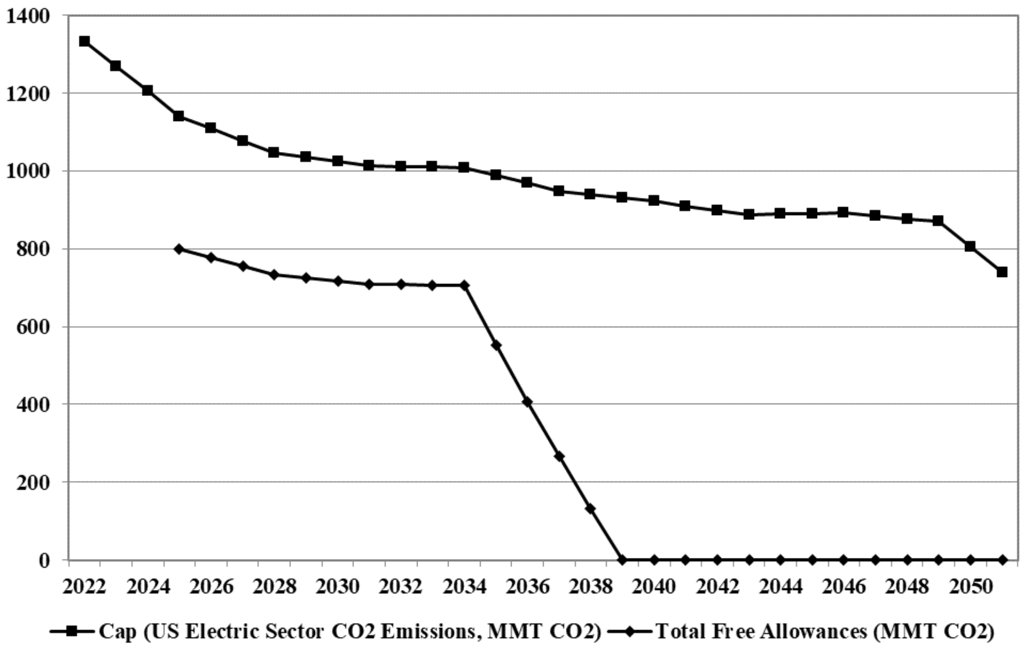


Sources: NERA calculations as explained in text.

2. Total Free Allocation

We assume that companies like Nevada Power and Sierra would receive 70 percent of the total annual allocation for ten years (from the beginning of the program in 2025 until 2034) and then the free allocation would decline linearly to zero by 2039. Figure C-3 shows the total electricity sector emissions and total free allowances that would be distributed to the electric sector under the presumed cap-and-trade program under the Mid CO_2 Price scenario.

Figure C-3. Total Electricity Sector Emissions and Free Allowances under Cap-and-Trade Program, Mid CO_2 Price Scenario (MMT CO_2)



Sources: NERA calculations as explained in text.

3. Shares of Allocation to Nevada Power and Sierra Based on Historical Emissions

The first criterion for apportioning the total allocation among individual companies is shares of the U.S. electricity sector's CO_2 emissions during an historical period. Under Waxman-Markey and Kerry-Lieberman, the historical period was the most recent three years (or an alternative set of three consecutive years selected by the company). We use three-year period from 2017 to 2019, which is the most recent period with complete data.

Under Waxman-Markey and Kerry-Lieberman, a company's historical CO_2 emissions include those from its net purchases of electricity. We estimated Nevada Power and Sierra's historical CO_2 emissions by summing emissions from their own generation and emissions from their net purchases, including PPAs and market purchases. We relied on emissions information provided by NV Energy on historical CO_2 emissions from their own generation for 2017-2019. Nevada

Power and Sierra's estimated historical CO_2 emissions from generation are shown below in Table C-1.

Table C-1. Historical CO_2 Emissions from NVE Generation (million metric tons of CO_2)

Year	NPC	SPPC
2017	8.4	2.6
2018	7.9	3.0
2019	7.4	3.1

Source: NV Energy.

We estimated Nevada Power and Sierra's historical CO_2 emissions from market purchases of electricity using information on the volume and region of market purchases from NV Energy and information on emission rates by region from U.S. EPA's eGrid data. We estimated an effective emissions rate for market purchases using the percent of purchases expected to come from each region and the regional emission rates. The volume of purchases, effective emissions rates, and emissions are shown below in in Table C-2.

Table C-2. Historical CO_2 Emissions from Market Purchases

	Market Purchases (million MWh)		Market Purchases CO_2 Rate	CO_2 Emissions (million metric tons)	
	NPC	SPPC	(mt/MWh)	NPC	SPPC
2017	2.0	3.0	0.30	0.6	0.9
2018	1.3	2.1	0.29	0.4	0.6
2019	0.6	3.1	0.29	0.2	0.9

Sources: NV Energy; EIA (2021a); NERA calculations as explained in text.

We estimated Nevada Power and Sierra's historical CO_2 emissions from PPAs using information on the PPA generators from NV Energy and information on the emission rates of those generators from eGrid. Table C-3 below shows the volume of purchases, effective emissions rates, and emissions for Nevada Power and Sierra PPAs that generate CO_2 emissions. Solar, hydroelectric, or other PPAs that do not generate CO_2 emissions are not included in Table C-3.

Table C-3. Historical CO_2 Emissions from PPAs

	Fossil-Fuel PPAs Purchases (million MWh)		Fossil-Fuel PPAs CO_2 Rate (mt/MWh)		CO_2 Emissions (million metric tons)	
	NPC	SPPC	NPC	SPPC	NPC	SPPC
2017	2.2	1.0	0.4	1.0	0.8	1.0
2018	2.2	1.0	0.4	1.0	0.8	1.0
2019	2.2	0.1	0.4	1.0	0.8	0.1

Sources: NV Energy; EIA (2021a); NERA calculations as explained in text.

Nevada Power and Sierra's estimated total historical CO_2 emissions, based on their emissions from generation, market purchases, and PPAs, are shown below in Table C-4. The table also includes total historical CO_2 emissions from the U.S. electricity sector based on data provided by EIA. We used this national information to estimate Nevada Power and Sierra's average shares of the U.S. electricity sector's total historical CO_2 emissions over the period 2017-2019.

Table C-4. Shares of Historical Emissions

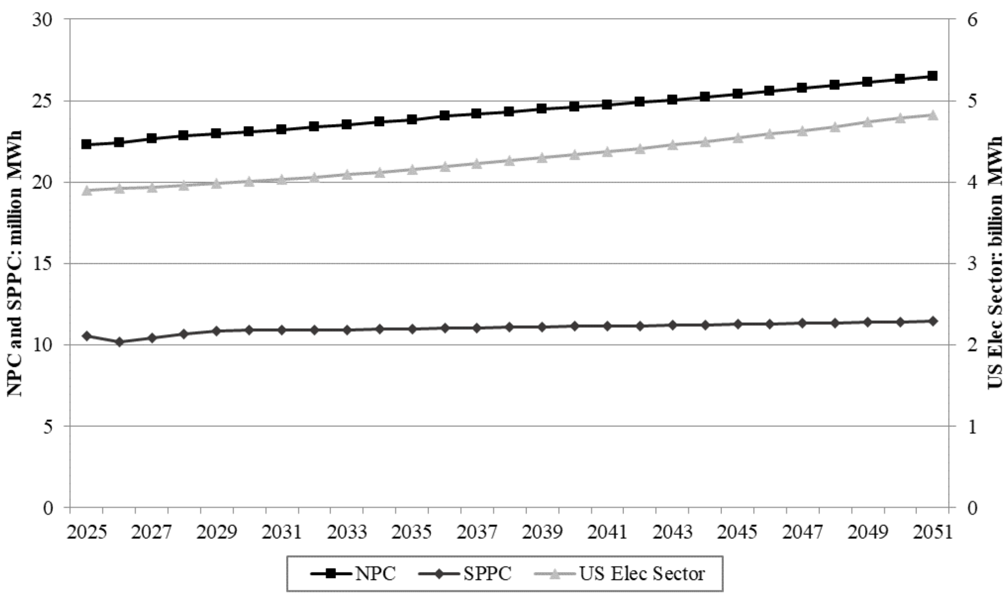
	Total CO_2 Emissions (million metric tons)			Share of US Elec CO_2 Emissions	
	NPC	**SPPC**	**US Elec**	**NPC**	**SPPC**
2017	9.8	4.5	1,742.8	0.56%	0.26%
2018	9.1	4.6	1,763.8	0.51%	0.26%
2019	8.3	4.1	1,617.9	0.52%	0.25%
Total	27.2	13.2	5,124.5	0.53%	0.26%

Sources: NV Energy; EIA (2021a); and NERA calculations as explained in text.

4. Shares of Free Allocation to Nevada Power and Sierra Based on Future Electricity Sales

The second criterion for apportioning the total LDC allocation among individual companies relates to shares of the U.S. electricity sector's sales for each future year from 2025 to 2051. Although the actual allocations would be based on future information, we use current projections from NV Energy and AEO 2021 to develop our estimates. For consistency, these projections are based on projections that do not include a CO_2 cap-and-trade program. Figure C-4 shows projected electricity sales by Nevada Power, Sierra, and the U.S. electricity sector.

Figure C-4. Projected Electricity Sales

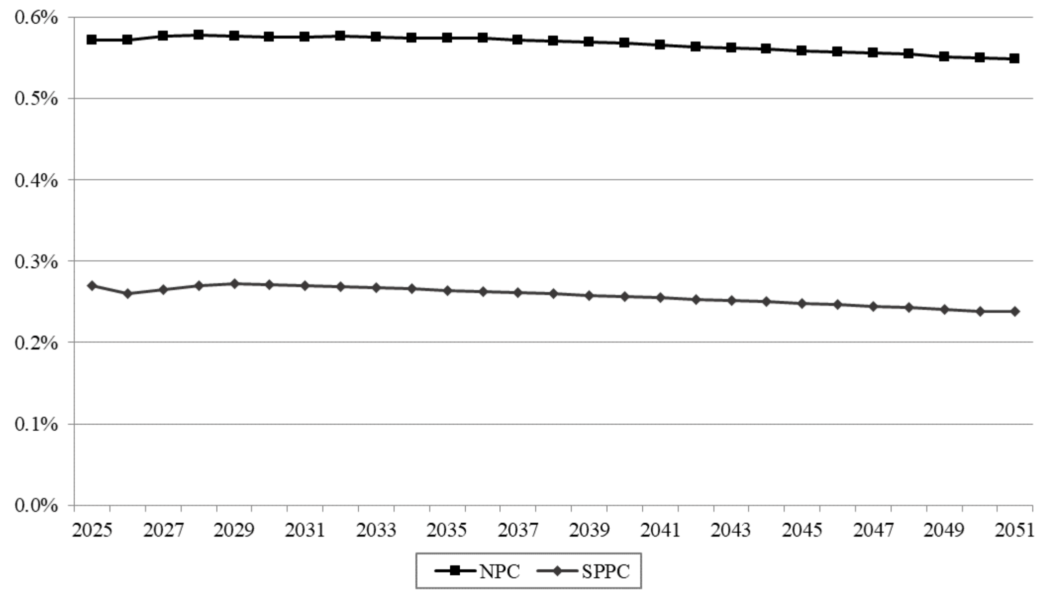


Sources: NV Energy; AEO (EIA 2021); NERA calculations as explained in text.

Based on Waxman-Markey and Kerry-Lieberman, we assume that shares of the U.S. electricity sector's sales would be updated every three years (i.e., sales shares in 2025 would be used for

2025, 2026, and 2027, sales shares in 2028 would be used for 2029, 2030, and 2031, etc.). Although these shares are based on projected sales under baseline conditions without a CO_2 cap-and-trade program, we believe they are reasonable estimates of Nevada Power and Sierra's shares of the U.S. electricity sector's sales under the potential CO_2 cap-and-trade program. (We do not have consistent estimates of Nevada Power and Sierra's sales under a CO_2 cap-and-trade program and an equivalent electricity-only program, and thus cannot calculate shares under the potential program.) Figure C-5 shows projected shares of U.S. electricity sales during the period 2025-2051 for Nevada Power and Sierra.[21]

Figure C-5. Shares of Projected U.S. Sales



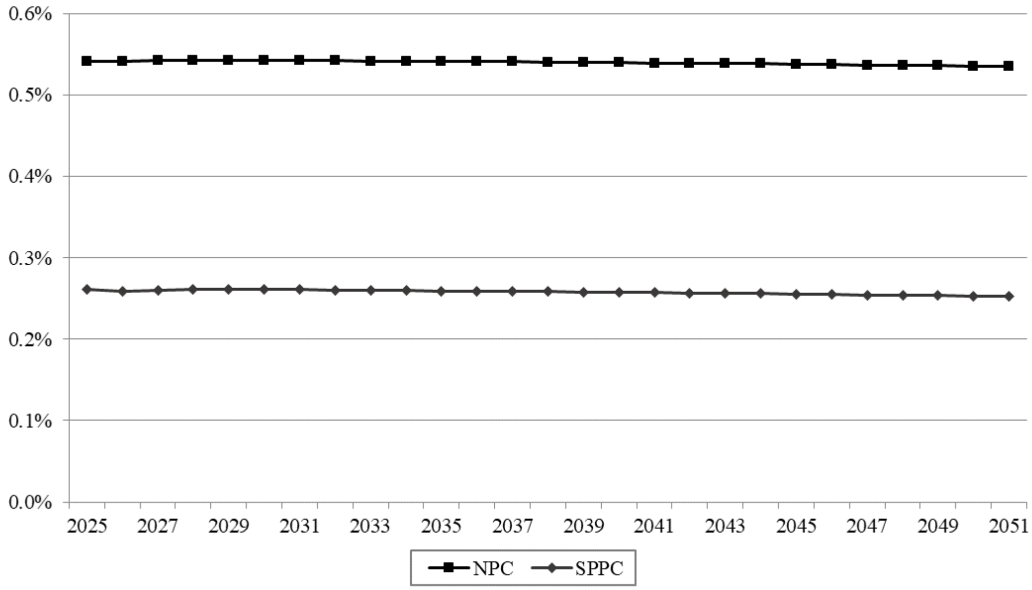
Sources: NERA calculations as explained in text.

5. Annual Shares and Allocations

As noted above, our calculations of allowance allocations use a formula in which 75 percent of the allocation to an individual electricity company is based on its share of historical emissions and 25 percent is based on its share of sales. Figure C-6 shows projected shares of the total LDC allocation for Nevada Power and Sierra. These projections use the weighted average of each company's shares of historical emissions (weighted 75 percent) and updated sales (weighted 25 percent).

[21] All NV Energy sales projections and CO_2 allocation values in this appendix reflect NV Energy's Base sales scenario.

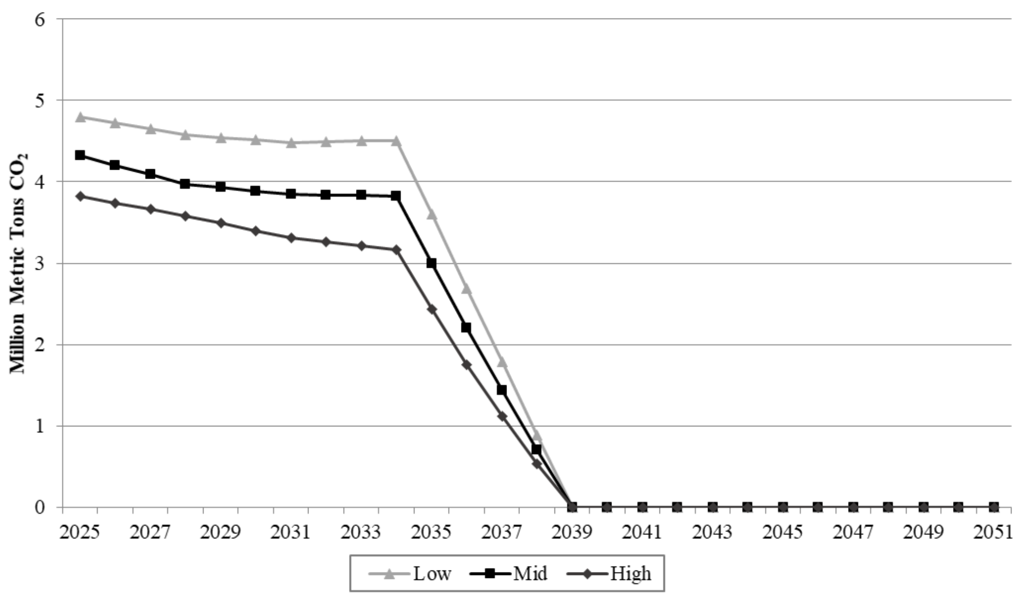
Figure C-6. Shares of Total Allocation to Electricity LDCs



Sources: NERA calculations as explained in text.

Figure C-7 shows the estimated quantities of CO_2 allowances allocated annually to Nevada Power under the Low, Mid, and High CO_2 price scenarios.

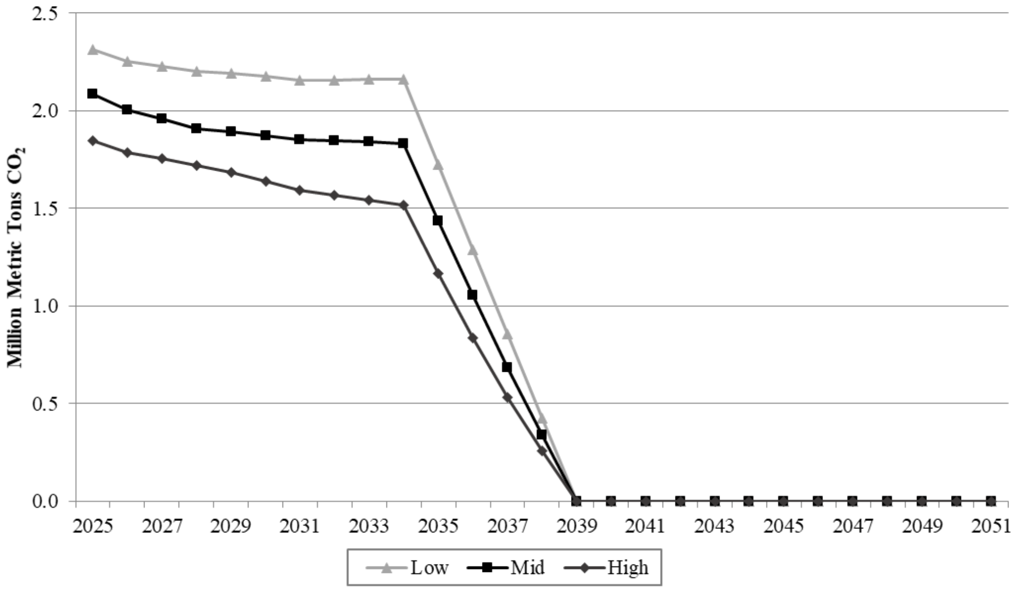
Figure C-7. CO_2 Allowance Allocations for NPC (Million Metric Tons of CO_2)



Sources: NERA calculations as explained in text.

Figure C-8 shows the estimated quantities of CO_2 allowances allocated annually to Sierra under the Low, Mid, and High CO_2 price scenarios.

Figure C-8. CO_2 Allowance Allocations for SPPC (Million Metric Tons of CO_2)

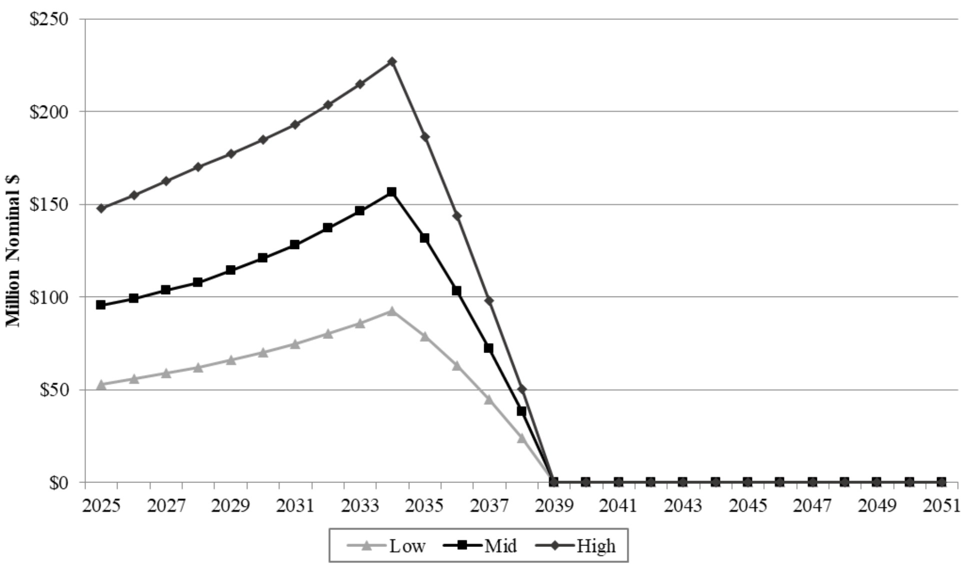


Sources: NERA calculations as explained in text.

6. Values of Annual Free Allocations to Nevada Power and Sierra

The annual values of CO_2 allowances allocated to Nevada Power and Sierra (in nominal dollars) were developed by multiplying the annual allocations above by the carbon prices in nominal dollars (see Appendix A). Figure C-9 shows the estimated nominal values of CO_2 allowances allocated annually to Nevada Power under the Low, Mid, and High CO_2 price scenarios.

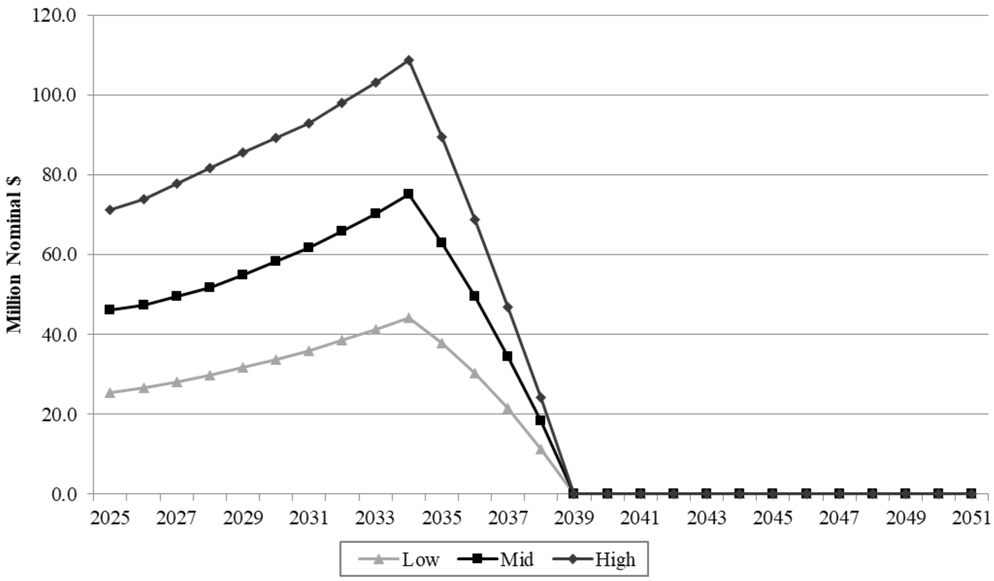
Figure C-9. CO_2 Allocation Value for NPC (Nominal$ Millions)



Sources: NERA calculations as explained in text.

Figure C-10 shows the estimated nominal values of CO_2 allowances allocated annually to Nevada Power under the Low, Mid, and High CO_2 price scenarios.

Figure C-10. CO_2 Allocation Value for SPPC (Nominal$ Millions)



Sources: NERA calculations as explained in text.

7. Present Values of Free Allocations to Nevada Power and Sierra

We estimated the present values of CO_2 allocations to Nevada Power and Sierra by discounting the annual allocation values above using nominal discount rates for the two Companies. Table C-5 shows the estimated present values of CO_2 allocation to Nevada Power and Sierra. These present values are calculated as of 2022 in 2022 dollars.

Table C-5. CO_2 Allocation Values (2022$ Millions)

	NPC	SPPC	Total
Low	$458	$228	$685
Mid	$787	$391	$1,179
High	$1,185	$588	$1,773

Notes: The values are present values in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra.

Sources: NERA calculations as explained in text.

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XII. Appendix D: Air Emissions

This appendix presents estimated air emissions under each of the four cases considered in this report. As noted in the report body, we used PROMOD electricity market modeling results from NV Energy and detailed emissions information from EPA to estimate emissions for NO_x, PM, VOC, SO_2, CO_2, and mercury.

The PROMOD modeling provided expected annual heat input for each unit in the Nevada Power and Sierra systems under each case. For each relevant unit owned by Nevada Power or Sierra in the output from the production cost modeling, NV Energy provided emission rates (per unit of heat input) for NO_x, PM, VOC, CO, SO_2, mercury, HCl, and CO_2. We supplemented these emission rates with emission rate data for specific units from eGRID (EPA 2021). The product of annual heat input and emission rates gives annual emissions for each unit. Summing the results for all units provides estimates of total annual emissions for each case from units in the Nevada Power and Sierra systems.

The PROMOD modeling also provided expected annual amounts of market energy purchases (MWh) under each case. Because specific sources of externally purchased power are unknown, we developed representative emission rates for purchased energy. NV Energy provided us with an estimate of the percentage of hours that each of three generation types (combined cycle gas turbine, non-combined cycle gas, and coal) is on the margin for various years throughout the forecast period. Using these estimates from NV Energy, as well as data from EPA's eGRID, we developed estimated emission factors for market power purchases. Emissions associated with power purchases were modeled as though they were emitted in Nevada, in accordance with regulatory requirements.

The following tables provide estimates of air emissions over time under each of the four cases. Emissions are measured in short tons for NO_x, VOC, PM, CO, SO_2, and HCl, in ounces for mercury, and in millions of metric tons for CO_2.

A. Nitrogen Oxides

The following table summarizes expected NO_x emissions for the four resource cases.

Table D-1. Emissions of Nitrogen Oxides (Short Tons)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
2022	4,812	4,812	4,812	4,812
2023	3,359	3,359	3,361	3,359
2024	2,446	2,446	2,515	2,446
2025	954	954	1,058	954
2026	900	900	1,568	900
2027	896	894	1,590	896
2028	888	884	1,546	888
2029	836	813	1,423	836
2030	825	802	1,380	806
2031	740	773	1,341	738
2032	650	699	1,287	647
2033	613	683	1,286	611
2034	575	727	681	573
2035	547	726	669	551
2036	545	711	666	525
2037	543	725	642	533
2038	571	706	624	522
2039	341	651	584	350
2040	332	635	532	341
2041	309	631	508	308
2042	405	516	453	404
2043	388	518	452	382
2044	389	467	434	351
2045	365	462	430	333
2046	363	463	451	336
2047	268	480	465	255
2048	264	509	480	257
2049	255	458	426	249
2050	249	406	405	236
2051	246	400	400	231

Note: A short ton is equal to 2,000 pounds.
Source: NERA calculations as explained in text.

B. Particulate Matter

The following tables summarize expected PM emissions for the four resource cases.

The emissions shown are PM_{10} emissions. Because the estimated damage values for PM emissions in this study are related to $PM_{2.5}$, we translate these emissions into effects on $PM_{2.5}$ concentrations before valuing the damages.

Table D-2. Emissions of Particulate Matter (Short Tons)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
2022	313	313	313	313
2023	317	317	317	317
2024	262	262	270	262
2025	191	191	207	191
2026	185	185	203	185
2027	190	190	203	190
2028	191	193	199	191
2029	194	190	189	194
2030	187	180	174	183
2031	173	179	171	173
2032	159	170	163	159
2033	154	170	164	152
2034	136	160	155	136
2035	129	158	150	129
2036	118	155	149	118
2037	112	155	147	111
2038	102	157	146	101
2039	87	154	145	90
2040	87	147	130	88
2041	82	141	126	81
2042	116	111	105	115
2043	109	109	104	108
2044	105	112	110	104
2045	102	110	109	101
2046	104	113	112	103
2047	80	91	90	79
2048	79	93	92	78
2049	79	90	89	79
2050	79	89	89	78
2051	79	88	88	78

Note: A short ton is equal to 2,000 pounds.
Source: NERA calculations as explained in text.

C. Volatile Organic Compounds

The following tables summarize expected VOC emissions for the four resource cases.

Table D-3. Emissions of Volatile Organic Compounds (Short Tons)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
2022	41	41	41	41
2023	39	39	39	39
2024	27	27	29	27
2025	19	19	21	19
2026	18	18	18	18
2027	19	19	19	19
2028	19	19	19	19
2029	20	20	18	20
2030	20	19	16	19
2031	18	18	16	17
2032	15	17	14	15
2033	15	18	15	15
2034	14	18	17	14
2035	13	17	15	13
2036	13	17	16	12
2037	13	18	15	12
2038	13	18	15	12
2039	8	13	12	8
2040	4	8	7	5
2041	4	8	7	4
2042	5	7	6	5
2043	5	7	6	5
2044	5	6	6	4
2045	5	6	6	4
2046	5	6	6	4
2047	3	6	6	3
2048	3	7	6	3
2049	3	6	6	3
2050	3	5	5	3
2051	3	5	5	3

Note: A short ton is equal to 2,000 pounds.
Source: NERA calculations as explained in text.

D. Carbon Monoxide

As discussed in the report body (see Section II.B), the effects of CO emissions are highly site-specific, and the requisite air quality modeling data were unavailable to develop estimated damage values for CO. Environmental costs associated with CO emissions are best determined during focused site-selection processes undertaken by utilities. We have, however, calculated expected levels of CO emissions under the four cases. We would not expect that including CO costs, if they could be estimated, would significantly change the estimates of costs for conventional air emissions and air toxics.

Table D-4. Emissions of Carbon Monoxide (Short Tons)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
2022	421	421	421	421
2023	437	437	438	437
2024	348	348	362	348
2025	170	170	197	170
2026	162	162	219	162
2027	167	167	225	167
2028	172	170	223	172
2029	178	172	208	178
2030	173	166	194	167
2031	152	161	187	151
2032	113	125	160	112
2033	109	126	164	109
2034	93	117	109	93
2035	83	110	101	84
2036	86	107	99	82
2037	84	102	94	82
2038	93	104	95	84
2039	44	79	74	46
2040	28	45	39	28
2041	26	44	38	26
2042	26	31	28	26
2043	25	32	28	25
2044	17	20	19	15
2045	16	20	19	14
2046	16	20	20	14
2047	12	21	21	11
2048	11	23	21	11
2049	11	20	19	11
2050	11	18	18	10
2051	10	18	18	10

Note: A short ton is equal to 2,000 pounds.
Source: NERA calculations as explained in text.

E. Sulfur Dioxide

The following table summarizes expected sulfur dioxide emissions for the four resource cases.

Table D-5. Emissions of Sulfur Dioxide (Short Tons)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
2022	397	397	397	397
2023	386	386	386	386
2024	379	379	379	379
2025	58	58	57	58
2026	55	55	56	55
2027	50	50	53	50
2028	44	44	47	44
2029	44	43	43	44
2030	42	41	41	41
2031	38	39	39	38
2032	35	37	37	35
2033	33	36	36	33
2034	30	34	33	30
2035	28	33	32	28
2036	25	32	31	25
2037	23	31	29	23
2038	22	31	29	22
2039	18	30	29	19
2040	18	29	26	18
2041	17	28	25	17
2042	21	21	20	21
2043	20	21	20	20
2044	16	17	17	16
2045	15	17	16	15
2046	16	17	17	15
2047	12	14	14	12
2048	12	15	14	12
2049	12	14	14	12
2050	12	14	14	12
2051	12	13	14	11

Note: A short ton is equal to 2,000 pounds.
Source: NERA calculations as explained in text.

F. Mercury

The following table summarizes expected mercury emissions for the four resource cases.

Table D-6. Emissions of Mercury (Ounces)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
2022	12	12	12	12
2023	11	11	11	11
2024	12	12	12	12
2025	6	6	5	6
2026	5	5	5	5
2027	4	4	4	4
2028	3	2	3	3
2029	2	2	2	2
2030	2	2	2	2
2031	2	2	2	2
2032	2	2	2	2
2033	1	2	1	1
2034	1	1	1	1
2035	1	1	1	1
2036	1	1	1	1
2037	0	0	0	0
2038	0	0	0	0
2039	0	0	0	0
2040	0	0	0	0
2041	0	0	0	0
2042	0	0	0	0
2043	0	0	0	0
2044	0	0	0	0
2045	0	0	0	0
2046	0	0	0	0
2047	0	0	0	0
2048	0	0	0	0
2049	0	0	0	0
2050	0	0	0	0
2051	0	0	0	0

Source: NERA calculations as explained in text.

G. Hydrogen Chloride

EPA's MATS sets limits on HCl as a surrogate for toxic acid gases. We follow EPA in not monetizing HCl emissions, but we do calculate expected HCl emissions under the four resource cases. The following table summarizes expected hydrogen chloride emissions for the four resource cases.

Table D-7. Emissions of Hydrogen Chloride (Short Tons)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
2022	10	10	10	10
2023	10	10	10	10
2024	10	10	10	10
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0
2030	0	0	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0
2035	0	0	0	0
2036	0	0	0	0
2037	0	0	0	0
2038	0	0	0	0
2039	0	0	0	0
2040	0	0	0	0
2041	0	0	0	0
2042	0	0	0	0
2043	0	0	0	0
2044	0	0	0	0
2045	0	0	0	0
2046	0	0	0	0
2047	0	0	0	0
2048	0	0	0	0
2049	0	0	0	0
2050	0	0	0	0
2051	0	0	0	0

Note: A short ton is equal to 2,000 pounds.
Source: NERA calculations as explained in text.

H. Carbon Dioxide

The following table summarizes expected carbon dioxide emissions for the four resource cases.

Table D-8. Emissions of Carbon Dioxide (Millions of Metric Tons)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
2022	10	10	10	10
2023	10	10	10	10
2024	8	8	9	8
2025	7	7	7	7
2026	7	7	7	7
2027	7	7	7	7
2028	7	7	7	7
2029	7	7	7	7
2030	7	6	6	6
2031	6	6	6	6
2032	6	6	6	6
2033	5	6	6	5
2034	5	6	6	5
2035	5	6	5	5
2036	4	6	5	4
2037	4	6	5	4
2038	4	6	5	4
2039	3	6	5	4
2040	3	5	5	3
2041	3	5	5	3
2042	4	4	4	4
2043	4	4	4	4
2044	3	3	3	3
2045	3	3	3	3
2046	3	4	3	3
2047	2	3	3	2
2048	2	3	3	2
2049	2	3	3	2
2050	2	3	3	2
2051	2	3	3	2

Note: A metric ton is equal to 1,000 kilograms.
Source: NERA calculations as explained in text.

References

U.S. Environmental Protection Agency ("EPA"). 2021. *Emissions and Generation Resource Integrated Database (eGRID)*. Data for 2021. https://www.epa.gov/egrid.

XIII. Appendix E: Air Quality Modeling

This appendix provides information on the air quality modeling results used in the development of estimated damage values for this study. The air quality modeling results rely upon previous analyses developed by Systems Applications International for Nevada Power ("Nevada Power Air Analyses") and Sierra ("Sierra Air Analyses"), representing the most complete data set available for Nevada. The Nevada Power Air Analyses and the Sierra Air Analyses are discussed in Harrison et al. (1993a) and Harrison et al. (1993b), respectively.

A. Information on Air Quality Modeling

1. Stack Parameters

The Nevada Power Air Analyses and the Sierra Air Analyses assessed potential air quality impacts for various technologies at different locations. In the analyses, each electricity-generating technology had a unique set of stack characteristics that produced a unique set of air quality effects. The analyses applied data on stack parameters including height, diameter, temperature, and exit velocity to assess the effects of emissions on air quality. The different facilities and stack characteristics considered are summarized in Table E-1 and Table E-2. The tables show that similar facilities and stack characteristics were evaluated in both analyses.

Table E-1. Stack Parameters Used for Dispersion Modeling in NPC Air Analyses

Type of Facility	Stack ht. (m)	Stack diam. (m)	Stack temp. (K)	Exit vel. (m/s)
Coal with Fluidized Bed 100-140 MW	76.00	3.00	410.0	27.43
Coal with Fluidized Bed 280-320 MW	122.00	4.66	410.0	27.43
Coal with Gasification 100-140 MW	76.00	4.48	400.0	27.43
Coal with Gasification 280-320 MW	122.00	8.10	400.0	27.43
Combined Cycle natural gas/oil 100-140 MW	70.10	3.47	421.3	18.44
Combined Cycle natural gas/oil 280-320 MW	87.33	4.88	408.0	18.90
Combustion Turbine with natural gas/oil 70-100 MW	19.10	4.10	803.4	37.60
Pulverized Coal w/scrub 100-140 MW	76.35	3.66	418.0	19.51
Pulverized Coal w/scrub 280-320 MW	121.92	4.88	408.0	22.86
Reciprocating Engine with diesel	15.24	1.30	783.0	45.70

Source: Harrison et al. (1993a).

Table E-2. Stack Parameters Used for Dispersion Modeling in SPPC Air Analyses

Type of Facility	Stack ht. (m)	Stack diam. (m)	Stack temp. (K)	Exit vel. (m/s)
Coal with Fluidized Bed 100-140 MW	76	3.00	410	27.50
Coal with Fluidized Bed 280-320 MW	122	4.90	408	22.90
Integrated Gasification Combined Cycle 100-140 MW	92	4.04	394	16.08
Combined Cycle natural gas/oil 100-140 MW	70	3.50	426	18.50
Combustion Turbine with natural gas/oil 70-100 MW	16.8	4.30	796	50.88
Pulverized Coal w/scrub 100-140 MW	76	3.70	420	19.30
Pulverized Coal w/scrub 280-320 MW	122	4.70	410	22.90
Reciprocating Engine with diesel	15.24	1.30	783	45.70

Source: Harrison et al. (1993b).

2. Locations

The air quality modeling determined the air quality impacts for alternative technologies at various locations, with effects varying based on meteorology and terrain.

Three locations were considered in the Nevada Power Air Analyses:

- *McCarren*, a site in Las Vegas Valley;
- *Desert Rock*, a site northwest of Las Vegas; and
- *Harry Allen near Garnet*, a site northwest of Las Vegas.

Four locations were considered in the Sierra Air Analyses:

- *Tracy Power Station*, an industrialized site about 15 miles from Reno with very complex terrain;
- *Stead*, an urban, mixed land-use site with moderately complex terrain;
- *Ft. Churchill Power Station*, a rural, agricultural site with moderately complex terrain; and
- *North Valmy Power Station*, a remote site with moderately complex terrain.

Thus, a total of seven locations were considered in the air quality modeling analyses.

3. Modeling Methodology

The air quality modeling involved organizing receptor locations on a Cartesian coordinate system with a domain size of 100 km x 100 km. For each of the plants and locations considered, associated stack parameters and emissions were placed at the center of the modeling domain. Incorporating meteorological data relevant to the specific locations, two models estimated concentrations of pollutants within the modeling domain. One model predicted concentrations of ambient PM_{10}

(made up of primary PM_{10}, nitrates, and sulfates) arising from emissions of PM_{10}, NO_x, and SO_2. Another model predicted ozone concentrations arising from NO_x and VOC emissions and the interaction of those emissions with other ambient conditions.

4. Modeling Results and Application to Environmental Cost Assessment

Both the Nevada Power Air Analyses and the Sierra Air Analyses yielded estimates of increased annual average ambient concentrations arising from one additional ton of pollutant for each modeling site and technology combination,[22] in other words, average ambient concentration changes per ton of emitted pollutant. Ambient concentration effects were modeled for ozone, PM_{10}, sulfates, nitrates, SO_2, and NO_2.[23] Thus, we can readily apply these air quality results to information on estimated tons of emissions (for different generating units, for the different relevant pollutants) to calculate ambient air quality effects under the four primary cases as well as the alternative case. Within the damage-function approach used in this study to develop estimated damage values for emissions not covered by a cap-and-trade program, the 1993 air quality results are only applied in the calculation of changes in ambient concentrations; the other aspects of the damage-function approach incorporate updated county-specific information related to the cases.

5. Specific Assumptions about Air Emissions

We develop estimated damage values for relevant emissions for a set of representative facilities in Nevada. Table E-3 summarizes the representative facilities and indicates which air quality analysis is relevant for each facility. For some facilities, we use average results from multiple applicable air quality analyses. When applying the air quality analyses to the representative facilities, we use information specific to each facility—such as size and stack structure—to develop appropriate estimates from the air quality analyses of the relevant relationship between ambient air quality and emissions.

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22 With the exception of ozone, which is measured in parts per billion, the other concentration changes are measured in $\mu g/m^3$.

23 The estimated damage values for PM in this study focus on effects from $PM_{2.5}$, not PM_{10}. Thus, we must convert effects on ambient PM_{10} concentrations to effects on ambient $PM_{2.5}$ concentrations. There does not appear to be consensus on the appropriate ratio but several documents (e.g., Parliamentary Assembly of the Council of Europe (1998), Swedish NGO Secretariat on Acid Rain (2006)) suggest that $PM_{2.5}$ concentration levels are around 60 to 70 percent of PM_{10} levels. We assumed a 65 percent ratio of $PM_{2.5}$ levels to PM_{10} levels for this study.

Table E-3. Representative Facilities and Application of Air Quality Analyses

Representative Facility Type	Location	Air Quality Analysis Used
Combustion Turbine	Clark County	Harry Allen (Nevada Power Air Analyses)
	Clark County	McCarren (Nevada Power Air Analyses)
Combined Cycle	Clark County	Harry Allen (Nevada Power Air Analyses)
	Clark County	McCarren (Nevada Power Air Analyses)
Coal	Clark County	Harry Allen (Nevada Power Air Analyses)
Combustion Turbine	Storey County	Tracy Power Station (Sierra Air Analyses)
Combined Cycle	Storey County	Tracy Power Station (Sierra Air Analyses)
Steam Turbine	Storey County	Tracy Power Station (Sierra Air Analyses)
Coal	White Pine County	North Valmy Power Station (Sierra Air Analyses)
IGCC	White Pine County	North Valmy Power Station (Sierra Air Analyses)
Steam Turbine	Lyon County	Ft. Churchill Power Station (Sierra Air Analyses)
Combustion Turbine	Humboldt County	North Valmy Power Station (Sierra Air Analyses)
Coal	Humboldt County	North Valmy Power Station (Sierra Air Analyses)
Coal	Elko County	North Valmy Power Station (Sierra Air Analyses)

Source: Nevada Power and Sierra 1993 air quality modeling.

A. Summary of Air Quality Modeling Results

Table E-4 provides the air quality modeling results used in this study from the Nevada Power Air Analyses and the Sierra Air Analyses. These data provide the information necessary for the development of estimated damage values for relevant emissions for representative facilities.

Table E-4. Increases in Concentrations of Ambient Pollutants per Ton of Emitted Pollutant (μg/m^3/ton)

Location	Type of Facility	Stack ht. (m)	Primary PM10	Sulfates	Nitrates	SO_2	NO2	Ozone (ppb)
Harry Allen (Nevada Power Air Analyses)								
Clark County	Combined Cycle	70	2.81E-5	0.30E-5	0.89E-7*	1.25E-5	0.28E-5	0.08E-7*
	Combined Cycle	87	2.46E-5	0.28E-5	0.89E-7*	1.19E-5	0.26E-5	0.08E-7*
	Combustion Turbine	19	2.77E-5	0.32E-5	0.89E-7*	1.36E-5	0.30E-5	0.08E-7*
	Pulverized Coal w/scrub	76	1.92E-5	0.30E-5	0.89E-7*	0.80E-5	0.20E-5	0.08E-7*
	Pulverized Coal w/scrub	122	1.54E-5	0.27E-5	0.89E-7*	0.71E-5	0.18E-5	0.08E-7*
McCarren (Nevada Power Air Analyses)								
Clark County	Combined Cycle	70	1.55E-5	0.30E-5	0.44E-7*	1.25E-5	0.28E-5	0.01E-6*
	Combined Cycle	87	1.47E-5	0.28E-5	0.44E-7*	1.19E-5	0.26E-5	0.01E-6*
	Combustion Turbine	19	1.68E-5	0.32E-5	0.44E-7*	1.36E-5	0.30E-5	0.01E-6*
	Pulverized Coal w/scrub	76	1.09E-5	0.30E-5	0.44E-7*	0.80E-5	0.20E-5	0.01E-6*
	Pulverized Coal w/scrub	122	0.98E-5	0.27E-5	0.44E-7*	0.71E-5	0.18E-5	0.01E-6*
Tracy Power Station (Sierra Air Analyses)								
Storey County	Combustion Turbine	16.8	2.69E-5	1.17E-5	4.06E-7	2.09E-5	8.06E-6	1.60E-5
	Combined Cycle	70	5.51E-5	3.37E-5	1.21E-6	3.78E-5	1.65E-5	1.60E-5
	Steam Turbine+	16.8	2.69E-5	1.17E-5	4.06E-7	2.09E-5	8.06E-6	1.60E-5
North Valmy Power Station (Sierra Air Analyses)								
White Pine, Humboldt,	Combustion Turbine	16.8	4.00E-5	1.65E-5	7.46E-7	3.15E-5	1.20E-5	3.20E-5
and Elko Counties and	Pulverized Coal w/scrub	76	5.44E-5	2.85E-5	1.34E-6	3.97E-5	1.63E-5	3.20E-5
Navajo Nation	Pulverized Coal w/scrub	122	2.57E-5	1.16E-5	5.34E-7	1.98E-5	7.71E-6	3.20E-5
	Integrated Gasification Combined Cycle	92	5.30E-5	2.78E-5	1.30E-6	3.87E-5	1.59E-5	3.20E-5
Ft. Churchill Power Station (Sierra Air Analyses)								
Lyon County	Steam Turbine+	16.8	4.51E-5	2.68E-5	9.18E-7	3.14E-5	1.35E-5	1.60E-5

Notes: * Based upon averages for different facilities
+ Based upon combustion turbine results
Source: Harrison et al. (1993a, 1993b).

The results of the Nevada Power Air Analyses and the Sierra Air Analyses suggest that the contribution of VOC emissions to ozone formation in Nevada is zero; thus, changes in ozone concentrations are entirely due to NO_x emissions.

References

Harrison, David, Albert Nichols, Sheri Bittenbender, and Mark Berkman. 1993a. *Final Report: External Costs of Electric Utility Resource Selection in Nevada.* Prepared for Nevada Power Company with assistance from Systems Applications International. Cambridge, MA: NERA, March.

Harrison, David, Albert Nichols, Mark Dreyfus, and Sheri Aggarwal. 1993b. *Final Report: External Costs of Electric Utility Resource Selection in Northern Nevada.* Prepared for Sierra Pacific Power Company with assistance from Systems Applications International. Cambridge, MA: NERA, December.

Parliamentary Assembly of the Council of Europe. 1998. *Fine-Particle Emissions and Human Health.* July 9.

The Swedish NGO Secretariat on Acid Raid. 2006. *Particles and Health: Factsheet from the Swedish NGO Secretariat on Acid Rain*. April.

XIV. Appendix F: Health Effects and Damage Values

This appendix provides details on the estimates of health effects and dollar damage values used in the development of estimated air pollution environmental costs in this study.

The conventional air emissions included and monetized in this study—NO_x, PM, VOC, SO_2—contribute to ambient concentrations of PM, ozone, and SO_2, as explained in Appendix E. We rely upon information developed by the U.S. Environmental Protection Agency ("EPA") to estimate and monetize the major health effects of PM, Ozone and SO_2. We note that we have not independently evaluated the scientific and valuation information developed by EPA and used in this study.

The appendix is organized as follows. Section A provides information on the health effects of the ambient pollutants included in our estimates, including the specific studies used to develop these estimates. Section B provides information on the valuations used to translate these health effects into damage values. Section C discusses effects that are not included in the damage estimates. We believe that accounting for omitted effects would not likely change the overall estimates of environmental costs in any significant way.

A. Health Effects Related to PM, Ozone, and SO_2

1. Overview of Pollutants Evaluated

a. Ambient $PM_{2.5}$ Concentrations

PM is a general category accounting for both solid particles and liquid droplets found in the air. Some particles are large or dark enough to be seen as soot or smoke. Others are so small they can be detected only with an electron microscope. PM_{10} refers to particles that are less than 10 micrometers (µm) in diameter while $PM_{2.5}$ refers to particles that are less than or equal to 2.5 µm in diameter.

PM can result from primary emissions and secondary atmospheric formation. Secondary particles are formed in the atmosphere from primary gaseous emissions, including SO_2 emissions and NO_x emissions. Generally, $PM_{2.5}$ is composed mostly of secondary particles, and PM_{10} is composed mostly of primary particles. When inhaled, particles can accumulate in the respiratory system and lead to health effects. These health effects are broadly classified as premature mortality effects and morbidity effects.

The EPA estimates we use in this study are for $PM_{2.5}$. Thus, for the health effects and damage values considered in this study, PM refers to $PM_{2.5}$, and the relevant ambient PM concentrations resulting from PM emissions are $PM_{2.5}$ concentrations.

b. Ambient Ozone Concentrations

Ozone is formed when NO_x and VOC emissions react in the presence of sunlight. Children, people with lung diseases such as asthma, and people who work or exercise outside are susceptible, through exposure to ozone, to potential adverse effects such as damage to lung tissue and reduction in lung function.

c. SO_2 Concentrations

The main source of SO_2 emissions is from the combustion of fossil fuels at power plants and other industrial facilities. As noted above, these emissions are also a precursor to particulates in the atmosphere. Short-term exposure to SO_2 is linked various respiratory health effects, including constriction of the airways in the lungs and increased hospital admissions for respiratory illness.

2. Overview of Concentration-Response Functions

Health effects associated with exposure to PM, ozone, and SO_2 are typically quantified using statistical (epidemiological) studies that provide estimated Concentration-Response ("C-R") functions. C-R functions for health effects take on several mathematical forms. One of the common forms is the following log-linear formulation (Abt Associates 2012a, pp. 45, 47):

$$\Delta Health\ Effect = \left(1 - \frac{1}{e^{\beta \cdot \Delta AirQuality}}\right) \cdot Baseline\ Incidence \cdot Relevant\ Population,$$

where Δ*Health Effect* is the change in the "risk" that people face of being adversely affected (e.g., develop chronic bronchitis) from a change from the baseline to the control pollutant exposure (Abt Associates 2012a), Δ*Air Quality* is the change in ambient air quality in appropriate units for a given pollutant, *Incidence* is the baseline rate of the health endpoint in the exposed population (among the relevant population), and the β parameter is the coefficient of the relevant pollutant. The relevant population is the specific population (e.g., only adults) for which the C-R is estimated.

Another common C-R functional form is the following logistic one:

where the basic logistic equation depends on the same variables as a basic log-linear equation.

$$\Delta Health\ Effect = \left(1 - \frac{1}{(1 - Incidence) \cdot e^{\beta \cdot \Delta Air\ Quality} + Incidence}\right) \cdot Incidence \cdot Relevant\ Population,$$

However, the logistic form often includes additional parameters, such as duration of symptoms.

3. Concentration-Response Functions Used in This Study

a. Background on Sources of EPA Information

We rely upon two broad sources of EPA information for the concentration-response function. The first is the set of most recent health effects included in EPA's evaluations of potential regulations, including a Regulatory Impact Analysis ("RIA") related to SO_2 (EPA 2010a) and a Technical

Support Document ("TSD") (EPA 2021a) that served as the basis for a RIA related to for PM and Ozone (2021b). The TSD, released in April 2021, is the latest effort by EPA to update its methodology to evaluate the health effects of PM and ozone. Both the RIA and the TSD include assessments by EPA of the epidemiologic studies establishing a relationship between PM2.5, ozone and SO_2 exposure and health outcomes as well as recommendations regarding which study to use and how to implement a consistent framework.

The second source of EPA information is BenMAP, a database of epidemiologic and economic studies that allows users to estimate human health benefits that result from changes in air quality (Abt Associates 2012b, p. 7). We use versions of BenMap for PM, Ozone and SO_2 to obtain further information on the relevant studies.

b. Specific Concentration-Response Functions

The following tables summarize the health effects and associated C-R functions used in this study for PM (Table F-1), ozone (Table F-2) and SO_2 (Table F-3). As an example, for premature mortality effects from PM, EPA recommends applying results from two cohort studies to quantify the relationship between exposure to PM and mortality (EPA 2021a, Table 10). EPA applies results of the two studies best characterizing risk across the U.S. for adults (Di et al., 2017, Turner et al., 2016). We average the damages associated with PM mortality derived from the functions underlying these two studies. In addition to premature adult mortality effects, EPA includes estimates of infant mortality in their primary estimates of health effects. These results rely on a study by Woodruff et al. (2008) that evaluated the relationship between post-neonatal infant mortality and PM. We also include this effect in our analysis.

Table F-1: Summary of Pollutant, Health Endpoints, and Source Study Information for PM

Health Endpoint	Study Author(s)	Study Population	Beta	Pollutant Metric
Mortality				
Mortality, All Cause	Woodruff et al., 2008	Infants	0.00560	24-hr Daily Average
Mortality, All Cause	Di et al., 2017	65 and older	0.00705	24-hr Daily Average
Mortality, All Cause	Turner et al., 2016	Adults (30 and older)	0.00583	24-hr Daily Average
Cardiovascular Effects				
HA, Cardio-, Cerebro- and Peripheral Vascular Disease	Bell et al., 2015	65 and older	0.00065	24-hr Daily Average
ER visits, All Cardiac Outcomes	Ostro et al., 2016	All ages	0.00061	24-hr Daily Average
Acute Myocardial Infarction, Nonfatal	Peters et al., 2001	Adults (18 and older)	0.02412	24-hr Daily Average
Acute Myocardial Infarction, Nonfatal	Peters et al., 2001	65 and older	0.02412	24-hr Daily Average
Acute Myocardial Infarction, Nonfatal	Pope et al., 2006	Adults (18 and older)	0.00481	24-hr Daily Average
Acute Myocardial Infarction, Nonfatal	Sullivan et al., 2005	Adults (18 and older)	0.00198	24-hr Daily Average
Acute Myocardial Infarction, Nonfatal	Zanobetti et al., 2009	Adults (18 and older)	0.00225	24-hr Daily Average
Incidence, Stroke	Kloog et al., 2012	65 and older	0.00343	24-hr Daily Average
Incidence, Out of Hospital Cardiac Arrest	Silverman et al., 2010	All ages	0.00392	24-hr Daily Average
Incidence, Out of Hospital Cardiac Arrest	Rosenthal et al., 2008	All ages	0.00198	24-hr Daily Average
Incidence, Out of Hospital Cardiac Arrest	Ensor et al., 2013	Adults (18 and older)	0.00638	24-hr Daily Average
Respiratory Effects				
ER visits, respiratory	Krall et al., 2016	All ages	0.00092	24-hr Daily Average
HA, Respiratory-2	Bell et al., 2015	65 and older	0.00025	24-hr Daily Average
HA, All Respiratory	Ostro et al., 2009	0- to 18-year-old	0.00275	24-hr Daily Average
Asthma Symptoms, Albuterol use	Rabinovitch et al., 2006		0.00200	24-hr Daily Average
Incidence, Asthma	Tetreault et al., 2016	0- to 17-year-old	0.04367	24-hr Daily Average
Incidence, Hay Fever/Rhinitis	Parker et al., 2009	3- to 17-year-old	0.02546	24-hr Daily Average
Minor Restricted Activity Days	Ostro and Rothschild, 1989	18- to 64-year-old	0.00741	24-hr Daily Average
Work Loss Days	Ostro, 1987	18- to 64-year-old	0.00460	24-hr Daily Average
Incidence, Lung Cancer				
Incidence, Lung Cancer	Gharibvand et al., 2016	Adults (30 and older)	0.03784	24-hr Daily Average
Nervous System Effects				
HA, Parkinsons Disease	Kioumourtzoglou et al., 2016	65 and older	0.07696	24-hr Daily Average
HA, Alzheimers Disease	Kioumourtzoglou et al., 2016	65 and older	0.13976	24-hr Daily Average

Sources: Adapted from EPA 2021a and EPA BenMAP-CE 1.5 Database.

Table F-2: Summary of Pollutant, Health Endpoints, and Source Study Information for Ozone

Health Endpoint	Study Author(s)	Study Population	Beta	Pollutant Metric
Mortality				
Mortality, Respiratory	Katsouyanni et al., 2009	All ages	0.00073	8-hr Daily Maximum
Mortality, Respiratory	Turner et al., 2016	Adults (30 and older)	0.00770	8-hr Daily Maximum
Mortality, Respiratory	Zanobetti and Schwartz, 2008	All ages	0.00083	8-hr Daily Maximum
Respiratory Effects				
HA, All Respiratory	Katsouyanni et al., 2009	65 and older	0.00028	1-hr Daily Maximum
ER visits, respiratory	Barry et al., 2018	All ages	0.00126	8-hr Daily Maximum
Incidence, Asthma	Tetreault et al., 2016	0- to 17 year-old	0.02075	8-hr Daily Maximum
Asthma Symptoms, Chest Tightness	Lewis et al., 2013	5- to 17-year-old	0.00759	8-hr Daily Maximum
Incidence, Hay Fever/Rhinitis	Parker et al., 2009	3- to 17-year-old	0.01655	24-hr Daily Average
Minor Restricted Activity Days	Ostro and Rothschild, 1989	18- to 64-year-old	0.00220	1-hr Daily Maximum
School Loss Days, All Cause	Gilliland et al., 2001	5- to 17-year-old	0.007824	8-hr Daily Maximum

Sources: Adapted from EPA 2021a and EPA BenMAP-CE 1.5 Database.

Table F-3: Summary of Pollutant, Health Endpoints, and Source Study Information for SO_2

Health Endpoint	Study Author(s)	Study Population	Beta	Pollutant Metric
Respiratory Effects				
HA, All respiratory	Schwartz et al. 1996	65 and older	0.00077	24-hr Daily Average
ER visits, Asthma	Ito et al. 2007	All ages	0.00437	24-hr Daily Average
ER visits, Asthma	Michaud 2004	All ages	0.00296	24-hr Daily Average
ER visits, Asthma	NYDOH 2006	All ages	0.00949	24-hr Daily Average
ER visits, Asthma	Peel et al. 2005	All ages	0.00074	1-hr Daily Max
ER visits, Asthma	Wilson 2005	All ages	0.01000	24-hr Daily Average
Asthma Exacerbations, One or more symptoms	Mortimer et al. 2002	4- to 12-year-old	0.00870	3-hr Daily Average
Asthma Exacerbations, One or more symptoms	O'Connor et al. 2008	4- to 12-year-old	0.00470	24-hr Daily Average
Asthma Exacerbations, One or more symptoms	Schildcrout et al 2006	4- to 12-year-old	0.00392	24-hr Daily Average
Acute Respiratory Symptoms	Schwartz et al. 1994	7- to 14-year-old	0.00862	24-hr Daily Average

Sources: Adapted from EPA 2010a (SO_2 NAAQS), EPA BenMAP 4.0 Database.

4. Application of C-R Functions to Estimate Health Effects

To develop estimated health effects for the four 2021 IRP cases, we combine the C-R functions for the suite of quantified health effects with ambient air quality effects for a set of representative facilities in Nevada. We develop baseline incidence rates and relevant population estimates for each plant and each health effect. For this information, we relied on the EPA BenMAP program and U.S. Census population data. As mentioned above, BenMAP is an environmental benefits mapping and analysis program, which contains an extensive database of national and, in some cases, county-level data on disease incidence rates. The database also includes population projections through 2050 developed by Woods & Poole Economics, Inc. We extrapolate these projections to 2051 based on the population growth rate over the study period.

a. Population Exposure

The air quality results developed as explained in Appendix E, which are inputs to the C-R functions, are calculated using modeling domains or grids, which are 100km by 100km for the various plants considered within the different cases. Thus, based on the relevant domain, we develop the appropriate population estimates covered within the domain. We rely on detailed population data at the Census Tract level using the 2010 U.S. Census. The Census Tract level data was obtained for each county based on the Census 100-Percent Data files. We combined coordinates of power plants with coordinates corresponding to the tracts to determine which tracts share any land with the 100km by 100km grid for each plant, and conservatively assumed the entire tract population whenever the grid overlapped the tract.

Both Nevada Power and Sierra purchase power generated by other entities, both within and outside the state of Nevada. The NAC requires that environmental costs from sources outside the State be included as part of the resource plan assessment (NAC 704.9359). However, the generator of power purchased on the open market is unknown. NV Energy has provided information on the source regions of purchased power from the market that allows us to estimate relevant emission rates for these purchases as well. We calculate the average emissions factors for the relevant regions based on the results of the N_{ew}ERA model so that the emissions factors are consistent with the carbon price scenario assumed for this analysis. We take a weighted average of those regional emissions factors to obtain an effective emissions rate for energy NV Energy purchases from the market.

We use this information to develop per-ton damage values for energy purchases by computing a weighted average of the damage values calculated for specific units in Nevada since the actual location, relevant population, baseline incidence rates, and other factors are unknown for purchases. Thus, we estimate the health effects of emissions from purchased power as if the purchased power were generated in Nevada.

b. Adjustment Factor for Population Growth

Because the cases extend to future years, our analysis also considers population growth. Population growth increases the number of people exposed to ambient pollutants and therefore increases the total potential number of incidences associated with these pollutants. To capture this dynamic effect, we use population forecasts available in BenMAP based on EPA's population growth database, which was developed by Woods & Poole Economics, Inc. We aggregate population-specific growth rates to the county level, and apply these growth rates to project affected populations at the tract level based on which county the tract is in.

B. Valuation of Health Effects Related to PM, Ozone, and SO_2

The final step in the damage-function approach involves developing dollar estimates for the various health effects discussed above. For these valuations, we rely on the valuation functions in BenMAP that have been used to develop dollar estimates in EPA regulatory impact analyses.

1. Valuation of Mortality Effects (Value of Statistical Life)

Over the past several decades, various methods have been devised to estimate how much people are willing to pay to reduce risks to life (and health). Some of the methods rely on the implicit tradeoffs that individuals make in daily decisions; for example, statistical models have been used to estimate the increased wages that workers demand in riskier occupations. Other methods rely on direct surveys of representative individuals, the results of which may be analyzed to produce demand curves for reduced mortality risk.

EPA uses valuations based on the concept of the "value of statistical life" or VSL to value mortality effects. The VSL measure represents the dollar value of small changes in mortality risk that are experienced by a large population. As described in the EPA's 2010 *Guidelines for Preparing Economic Analyses ("Guidelines")*: "VSL estimates are derived from aggregated estimates of individual values for small changes in mortality risks. For example, if 10,000 individuals are each willing to pay $500 for a reduction in risk of 1/10,000, then the value of saving one statistical life equals $500 times 10,000 — or $5 million. Note that this does not mean that any single identifiable life is valued at this amount. Rather, the aggregate value of reducing a collection of small individual risks is, in this case, worth $5 million" (EPA 2010b, p. XV).

Economists have developed estimates of the VSL using evidence on market choices, which involve implicit tradeoffs between mortality risk and monetary compensation (see Viscusi and Aldy 2003, p. 5). As noted by Viscusi and Aldy, one of the main concerns regarding VSL estimates in different contexts is how these values vary with income. Viscusi and Aldy's extensive meta-analysis includes a discussion of this and other issues, including the uncertainty around the VSL estimates that have been developed in the literature (Viscusi and Aldy 2003).

2. Valuation of Morbidity Effects

The other major valuation component relates to morbidity effects, which is a measure of "being diseased or afflicted by an illness" (i.e., these are non-fatal effects in contrast to premature mortality) (Abt Associates 2012a). As noted in the EPA *Guidelines*, the willingness-to-pay to reduce the risk of experiencing one of these non-fatal health effects is the preferred measure for valuing morbidity effects (EPA 2010b, p. 7-12). The three methods that are most frequently utilized for valuing morbidity effects in an environmental context are stated preference, averting behavior, and cost of illness (EPA 2010b, p. 7-12).

Stated preference approaches use surveys to elicit respondents' willingness-to-pay for a potential change in a non-market good based on one or a serious of hypothetical scenarios. The averting behavior approach aims to infer the value for an improvement in environmental quality by assessing the actions that individuals take (e.g., purchasing air filters) "to avoid or mitigate the increased health risks or other undesirable consequences of reductions in ambient environmental quality conditions" (EPA 2010b, p. 7-31). Finally, the avoided cost of illness is a common alternative to willingness-to-pay estimates. As noted by EPA, this method estimates "the financial burden of an illness based on the combined value of direct and indirect costs associated with the illness", where direct costs include diagnosis, treatment, and rehabilitation expenditures while indirect costs include the value of aspects such as lost income, productivity, and leisure time related to the illness (EPA 2010b, p. 7-33).

3. Adjustment Factor for Income Growth

According to EPA, there is substantial evidence that people are willing to pay more for some health risk reductions as their income increases. In its regulatory impact analyses, EPA uses income growth projections to adjust all values that are based on a measure of willingness to pay, as well as for the VSL. Cost of Illness ("COI") estimates are not adjusted according to changes in income elasticity due to the fact that COI estimates capture the direct cost of a health outcome. EPA develops adjustment factors to account for real income growth based on elasticity values—derived in Kleckner and Neumann (1999)—population projections, and GDP per capita projections. EPA recommends using income elasticity estimates specific to the type of health endpoint associated with the WTP estimate for three types of health effects: minor, severe and mortality. Three different adjustment factors are used, with the lowest for minor health effects, the middle factor for premature mortality, and the highest factor for severe and chronic health effects (EPA 2021a). These adjustment factors are available as a database in BenMAP through 2050, and we use the average growth rate of 2046 through 2050 to extrapolate income growth to the year 2051.

4. Specific Valuation Estimates Used in this Study

Table F-4 summarizes EPA's assumed values per incidence of health endpoints based on EPA regulatory impact analyses. Our values rely on the same underlying valuation functions but can vary from those in this table due to location- and population-specific factors (e.g., valuation functions depend on age, income, etc.).

Table F-4: EPA Assumed Values per Incidence of Health Endpoints (2022$)

	2020 Income	2030 Income	2040 Income	2050 Income
Premature Mortality (VSL)				
3% discount rate	$10,662,117	$11,143,971	$12,244,457	$14,149,576
7% discount rate	$9,602,878	$10,036,862	$11,028,019	$12,743,872
Non-fatal Myocardial Infarction				
3% discount rate	$82,112	$82,112	$82,112	$82,112
7% discount rate	$78,271	$78,271	$78,271	$78,271
Hospital Admissions:				
All respiratory	$44,016	$44,016	$44,016	$44,016
Alzheimers disease				
3% discount rate	$222,943	$222,943	$222,943	$222,943
7% discount rate	$176,356	$176,356	$176,356	$176,356
Cardio-, cerebro-, and preipheral vascular disease	$18,705	$18,705	$18,705	$18,705
Parkinsons disease				
3% discount rate	$685,487	$685,487	$685,487	$685,487
7% discount rate	$538,678	$538,678	$538,678	$538,678
Emergency room visits, all cardiac outcomes	$1,403	$1,403	$1,403	$1,403
Emergency room visits, asthma	$592	$592	$592	$592
Emergency room vists, respiratory	$1,057	$1,057	$1,057	$1,057
Other respiratory effects				
Asthma symptoms	$243	$247	$255	$269
Incidence, asthma				
3% discount rate	$53,206	$53,206	$53,206	$53,206
7% discount rate	$32,975	$32,975	$32,975	$32,975
Incidence, hay fever/rhinitis	$725	$725	$725	$725
Other cardiovascular effects				
Incidence, stroke	$41,038	$41,038	$41,038	$41,038
Incidence, out of hospital cardiac arrest				
3% discount rate	$43,203	$43,203	$43,203	$43,203
7% discount rate	$42,633	$42,633	$42,633	$42,633
Incidence, lung cancer				
3% discount rate	$40,853	$40,853	$40,853	$40,853
7% discount rate	$39,330	$39,330	$39,330	$39,330
Work and Activity Related:				
Work Loss Days	$204	$204	$204	$204
School Absence Days	$125	$125	$125	$125
Minor Restricted Activity Days	$84	$86	$89	$94

Notes: Premature mortality values reflect EPA's current VSL of $7.8 million in 2015 dollars for income in 2015. We follow EPA in adjusting to 2020 dollars using the appropriate indices in the BenMAP database (and then from 2020 to 2022, we use inflation information from NV Energy). For income adjustments, we follow EPA and adjust the values to each year's income level using EPA's income growth adjustment factor database from BenMAP CE 1.5.8 until 2050 and our extrapolation of these factors for 2051. As noted above, the values used in our analysis rely on the valuation functions underlying EPA's results and at times will vary slightly from those presented here (e.g., when the functional form requires county-specific income, when the valuation depends on the affected age group, etc.).

Sources: Adapted from EPA 2021a and BenMAP-CE 1.5 Database.

C. Non-Quantified Potential Environmental Costs Related to Conventional Air Emissions

Several non-health welfare effects have been associated with ambient PM, ozone, and SO_2 concentrations. These effects include visibility effects, damages to property (e.g., soiling), agricultural yield effects, and ecosystem effects. However, quantification of these effects can be difficult or even impracticable. The latest regulatory impact analysis in which EPA monetized the environmental costs associated with exposure to PM and ozone, based upon the TSD, does not estimate the additional benefits from improvements in welfare effects (EPA 2021b, 5-39) and neither does the latest regulatory impact analysis for SO_2 (EPA 2010a, 5-8).

Given data and other limitations, we have not quantified these effects. But we believe that these effects are not likely to be significant relative to the environmental costs we have quantified.

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XV. Appendix G: Environmental Costs for Conventional and Air Toxic Emissions by Facility Type

This appendix presents estimated environmental costs due to air emissions (conventional and air toxic pollutants) by facility type. Table G-1 presents facility-specific estimates of environmental costs associated with conventional air emissions for the four cases.

Table G-1. Environmental Costs of Conventional Air Emissions and Air Toxics by Facility Type (2022$ Millions)

	Net-Zero	Iron_Hot	Repower Valmy	Geo
NVE Existing Generation	**$26.29**	**$27.94**	**$27.25**	**$26.26**
CCs	$25.14	$26.79	$26.10	$25.12
CTs	$0.99	$0.99	$0.92	$0.98
Coal	$0.16	$0.16	$0.24	$0.16
Cogen	$0.00	$0.00	$0.00	$0.00
NVE New Generation	**$2.86**	**$3.40**	**$3.22**	**$2.83**
CCs	$2.80	$3.19	$3.05	$2.78
CTs	$0.06	$0.21	$0.17	$0.05
Power Purchases	**$0.74**	**$0.79**	**$0.76**	**$0.74**
CCs	$0.04	$0.04	$0.04	$0.04
CTs	$0.00	$0.00	$0.00	$0.00
Coal	$0.00	$0.00	$0.00	$0.00
Cogen	$0.29	$0.29	$0.29	$0.29
Market	$0.41	$0.45	$0.42	$0.40
Total	**$29.90**	**$32.14**	**$31.23**	**$29.83**

Note: "CCs" denote combined cycle units; "CTs" denote combustion turbine units; "Cogen" denotes cogeneration.
All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra.

Source: NERA calculations as explained in text.

XVI. Appendix H: Social Costs of Carbon

This appendix provides information on the methodology and results used to evaluate the social costs of carbon of the alternative resource plans. As noted in Chapter IV.B above, we develop these values based on the requirements identified in the Commission's August 2018 final regulation to implement Senate Bill 65.

A. Commission Requirements to Assess the Social Costs of Carbon

The Commission's August 2018 final regulation to implement Senate Bill 65 includes the following requirements related to evaluation of the social costs of carbon for the purposes of the utility's supply plan evaluation.

> For the purposes of subsection 4 and NAC 704.9215 and 704.9359, the social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics such as the analysis set forth in the 'Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis' released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016.[24]

Thus, for years in which there would not be a binding cap-and-trade program (2021-2024) we calculate social cost of carbon values by applying global economic cost values developed by the Interagency Working Group; and for years in which there would be a binding cap-and-trade program (2025-2051), we calculate the social cost of carbon values as equal to the global economic cost values minus the costs internalized as private costs, which are equal to the allowance prices under the Mid CO_2 Price scenario.[25]

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[24] Amendments to NAC 704.937, as identified in LCB File No. R060-18 (Section 3, subheading 5).

[25] Note that there is some ambiguity in using the term "social cost of carbon" under the Commission requirements. The Interagency Working Group refers to the values they developed as the "social cost of carbon," and, indeed, this term is widely used by regulatory agencies and others to refer to these values. Because the Commission uses the term "social cost of carbon" to refer to the portion of such costs that is not internalized, we refer to the values developed by the Interagency Working Group as "global economic costs," consistent with the Commission usage.

B. Interagency Working Group Global Economic Cost of Carbon Dioxide Emissions Values

This section provides background on the methodology used by the Interagency Working Group to develop estimates of the global economic cost of carbon dioxide emissions.

1. Overview of the Methodology of the Interagency Working Group to Develop Provisional Estimates of the Global Economic Cost of Carbon Dioxide Emissions

The Interagency Working Group notes that the social cost of carbon is a monetized estimate of the damages resulting for an incremental increase in CO_2 emissions in a given year. The value is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of the ecosystem services due to climate change. The methodology of the Interagency Working Group is based upon the use of three integrated assessment models of climate change ("IAMs") to develop estimates of the damages due to a marginal increase in CO_2 emissions. In July 2015, the Interagency Working Group published updated SCC estimates that used the updated versions of the three IAMs used in the prior SCC estimates, but it did not otherwise revisit its methodological assumptions; these same values are included in the August 2016 report.[26] In February 2021, the Interagency Working Group published interim results that update those included in the August 2016 report for inflation. Revised standards are expected to be developed by January 2022. The following summarizes the methodologies of the IAMs and the specific steps the Interagency Working Group used to develop its estimates in 2010, 2013, 2015, and 2021.

IAMs are complex models of the global climate and economy that translate CO_2 emissions into changes in the climate system (most notably, temperature increases), and then translate these changes in the climate system into various types of economic damages, summarized by losses in GDP. The Interagency Working Group notes that the advantage of IAMs is that they combine climate processes, economic growth, and feedbacks between the climate and the global economy into a single modeling framework. This advantage comes at the expense of more detailed representations of the underlying climate and economic systems.

The Interagency Working Group relies on three IAMs for its calculations of the SCC.[27] Although the basic methodologies of these three models are similar, they have produced significantly different results (see Nordhaus 2008, Hope 2008, Tol 2002a, Tol 2002b), which can be attributed to the "simplifying assumptions and judgments reflecting the various modelers' best attempts to synthesize the available scientific and economic research characterizing these relationships"

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[26] The initial SCC estimates were published in February 2010. Updated estimates were later published in May and July of 2013, in July of 2015 (with the 2015 values included in the August 2016 report). In February 2021, the SCC estimates were updated for inflation, but were not otherwise changed.

[27] The three models are known as the DICE, PAGE and FUND models. See Interagency Working Group (2010) for full descriptions of these models.

(Interagency Working Group 2010, pp. 5-6). The goal of the Interagency Working Group is to respect the different approaches to quantifying damages while using a consistent set of input parameters, selected after conducting an extensive review of the literature (Interagency Working Group 2010).

As a starting point, the modeling effort requires a baseline set of socio-economic (GDP and population) pathways and associated carbon dioxide emissions trajectories. The Interagency Working Group (in both the 2010 report and subsequent updates) bases these inputs on the Stanford Energy Modeling Forum Exercise of 2009 (Interagency Working Group 2015, p.12). This modeling effort uses well-recognized models to evaluate substantial, coordinated action to meet specific stabilization targets (Interagency Working Group 2010). Five internally consistent pathways of GDP, population and emissions trajectories are chosen by the Interagency Working Group in the 2015 update to reflect a range of plausible outcomes. These are the same five scenarios as considered in developing the original 2010 SCC estimates (Interagency Working Group 2015, p.12).

The next step is to translate carbon dioxide emissions into changes in the climate system. The key input is the "equilibrium climate sensitivity" parameter, which is the long-term increase in global-average surface temperature resulting from a doubling of atmospheric CO_2 concentration (relative to pre-industrial levels). The true value of this parameter is unknown, so the Interagency Working Group uses the Roe and Baker Equilibrium climate sensitivity distribution calibrated to the IPCC Fourth Assessment Report.

Changes in the climate system are then converted into economic damages, represented by changes in global GDP. Each of the three IAMs has a different method, based largely on how rapidly damages increase with more extreme changes in the climate. The models each make explicit or implicit assumptions about the effectiveness of human efforts to adapt to changes in the climate and the possibility of the occurrence of catastrophic climate events. Instead of choosing one method, the Interagency Working Group ran each of the three models with its selected input parameters and weighs the results from the three models equally.

Finally, future damages from carbon dioxide emissions are converted into present values. The Interagency Working Group notes that there is "no consensus" on what is the appropriate discount rate to use in this context, with estimates in the literature ranging from nearly zero (Stern et al. 2006) to market rates (Just et al. 2004). For this reason, a range of real (i.e. inflation adjusted) discount rates is considered, with values reported from 2.5 percent to 5 percent. A constant 3 percent discount rate is referred to the "central value."

2. Interagency Working Group Calculations of Global Economic Cost of Carbon Dioxide Emissions

The steps the Interagency Working Group used to calculate the environmental costs of CO_2 emissions (for a given discount rate) in each year *t* are:

1. Input the path of emissions, GDP, and population and calculate the year by year paths of temperature and per capita consumption associated with the baseline path of emissions;

2. Add an additional unit of CO_2 emissions in year *t* and recalculate the year by year paths of temperature and per capita consumption in all years beyond *t* resulting from this adjusted path of emissions;

3. Compute the marginal damages in each year as the difference between the per capita consumption computed in Step 1 and Step 2; and

4. Discount the resulting path of marginal damages back to the year of emissions using the fixed discount rates and calculate the SCC as the net present value of the discounted path of damages (Interagency Working Group 2010, p. 24-25).

Because uncertainty is incorporated into the modeling, the result is a distribution of annual environmental cost estimates. For each discount rate, these four steps are repeated for each of the three IAMs with each of the five socio-economic and emissions trajectories. This results in 15 different distributions of the annual present value of global economic cost or carbon for each of the three discount rates (2.5 percent, 3 percent and 5 percent). These distributions are equally weighted and combined to produce a single distribution of annual global economic cost values for a given discount rate. Table H-1 summarizes the trajectory of annual global economic cost values reported by the Interagency Working Group for each of these three discount rates. The Interagency Working Group provides results for the mean of the distribution for each of the three discount rates, as well as for the 95th percentile for the 3 percent discount rate (Interagency Working Group 2016, p. 25).

Table H-1. Interagency Working Group Global Economic Costs of Carbon Values (2022$/metric ton)

Discount Pct. Distr.	5% Avg	3% Avg	2.5% Avg	3% 95th
2022	$16.1	$55.4	$82.2	$165.0
2023	$16.6	$56.5	$83.6	$168.7
2024	$17.1	$57.6	$84.9	$172.3
2025	$17.6	$58.7	$86.3	$176.0
2026	$18.1	$59.8	$87.7	$179.6
2027	$18.6	$60.9	$89.0	$183.3
2028	$19.1	$62.0	$90.4	$187.0
2029	$19.6	$63.1	$91.7	$190.6
2030	$20.1	$64.3	$93.1	$194.3
2031	$20.8	$65.4	$94.5	$198.2
2032	$21.4	$66.6	$95.9	$202.2
2033	$22.0	$67.8	$97.4	$206.2
2034	$22.6	$69.0	$98.8	$210.2
2035	$23.2	$70.2	$100.2	$214.1
2036	$23.8	$71.4	$101.6	$218.1
2037	$24.4	$72.6	$103.0	$222.1
2038	$25.0	$73.8	$104.4	$226.1
2039	$25.6	$75.0	$105.9	$230.1
2040	$26.2	$76.2	$107.3	$234.0
2041	$26.9	$77.4	$108.7	$237.7
2042	$27.6	$78.5	$110.1	$241.3
2043	$28.2	$79.7	$111.4	$245.0
2044	$28.9	$80.9	$112.8	$248.6
2045	$29.6	$82.1	$114.2	$252.2
2046	$30.3	$83.3	$115.6	$255.9
2047	$30.9	$84.5	$117.0	$259.5
2048	$31.6	$85.7	$118.4	$263.2
2049	$32.3	$86.9	$119.8	$266.8
2050	$32.9	$88.1	$121.2	$270.4
2051	$33.6	$89.3	$122.6	$274.1

Notes: Dollar values have been converted to 2022$ using inflation information from NV Energy.
Source: Interagency Working Group (2021).

C. Developing Estimates of the Social Cost of Carbon

Using the methodology required by the Commission, the values of the social cost of carbon differ depending upon whether or not the cap-and-trade program is in effect. For the years before the cap-and-trade program is in effect (2021-2024), we multiply the estimated CO_2 emissions by the Interagency Working Group global economic costs of CO_2 values shown in Table H-1.

For years in which the cap-and-trade program is in effect, we multiply the estimated CO_2 emissions by the Interagency Working Group Value for that year minus the assumed CO_2 allowance price for that year. Table H-2 provides the annual allowance prices used for the Mid CO_2 price scenario.[28] Table H-3 shows the Interagency Working Group values minus the allowance price values. Consistent with the requirements identified in the August 2018 final rule, we use the values in Table H-3 to develop estimates of the social costs of CO_2 emissions.

[28] The Mid CO_2 price scenario assumes a binding cap-and-trade program would begin in 2025. Appendix B provides additional information on the assumptions and modeling underlying the Mid CO_2 price scenario.

Table H-2. CO_2 Allowance Prices for the Mid CO_2 Price Scenario (2022$/metric ton)

	CO_2 Allowance Price (2022$/MT)
2022	$0.0
2023	$0.0
2024	$0.0
2025	$20.8
2026	$21.8
2027	$22.9
2028	$24.1
2029	$25.3
2030	$26.6
2031	$27.9
2032	$29.3
2033	$30.7
2034	$32.3
2035	$33.9
2036	$35.6
2037	$37.4
2038	$39.2
2039	$41.2
2040	$43.3
2041	$45.4
2042	$47.7
2043	$50.1
2044	$52.6
2045	$55.2
2046	$58.0
2047	$60.9
2048	$63.9
2049	$67.1
2050	$70.5
2051	$74.0

Notes: Dollar values have been converted to 2022$ using inflation information from NV Energy. The Mid CO_2 Price scenario assumes a binding all-sector national cap-and-trade program for CO_2 emissions would begin in 2025.

Source: NERA calculations as explained in text.

Table H-3. Social Costs of Carbon Values for the Mid CO_2 Price Scenario (2022$/metric ton)

Discount	5%	3%	2.5%	3%
Pct. Distr.	Avg	Avg	Avg	95th
2022	$16.1	$55.4	$82.2	$165.0
2023	$16.6	$56.5	$83.6	$168.7
2024	$17.1	$57.6	$84.9	$172.3
2025	$0.0	$37.9	$65.5	$155.2
2026	$0.0	$38.0	$65.8	$157.8
2027	$0.0	$38.0	$66.1	$160.4
2028	$0.0	$37.9	$66.3	$162.9
2029	$0.0	$37.9	$66.4	$165.3
2030	$0.0	$37.7	$66.5	$167.7
2031	$0.0	$37.6	$66.6	$170.3
2032	$0.0	$37.4	$66.7	$172.9
2033	$0.0	$37.1	$66.6	$175.4
2034	$0.0	$36.7	$66.5	$177.9
2035	$0.0	$36.3	$66.3	$180.3
2036	$0.0	$35.8	$66.0	$182.5
2037	$0.0	$35.2	$65.7	$184.7
2038	$0.0	$34.5	$65.2	$186.8
2039	$0.0	$33.8	$64.7	$188.9
2040	$0.0	$32.9	$64.0	$190.8
2041	$0.0	$31.9	$63.2	$192.3
2042	$0.0	$30.9	$62.4	$193.6
2043	$0.0	$29.7	$61.4	$194.9
2044	$0.0	$28.3	$60.3	$196.0
2045	$0.0	$26.9	$59.0	$197.0
2046	$0.0	$25.3	$57.6	$197.9
2047	$0.0	$23.6	$56.1	$198.7
2048	$0.0	$21.8	$54.5	$199.3
2049	$0.0	$19.8	$52.7	$199.7
2050	$0.0	$17.6	$50.7	$200.0
2051	$0.0	$15.3	$48.6	$200.1

Notes: Dollar values have been converted to 2022$ using inflation information from NV Energy. Values reflect the Interagency Working Group global economic cost values provided in Table H-1 minus the CO_2 allowance prices for the Mid CO_2 Price Scenario provided in Table H-2 for consistency with the Commission requirements as identified in the final regulation to implement SB 65.

Source: Interagency Working Group (2021) and NERA calculations as explained in text.

D. Social Costs of Carbon for the Four Resource Cases

We use CO_2 emissions (included in Appendix D) based on PROMOD electricity market modeling results developed from NV Energy to estimate the social costs of carbon dioxide emissions. As noted, since the Mid CO_2 Price scenario assumes that a binding cap-and-trade program would begin in 2025, we value CO_2 emissions for the period 2021-2024 based on the annual global economic cost values for each discount rate developed by the Interagency Working Group. For the period 2025-2051, in which we assume there would be a binding cap-and-trade program, we use social cost of carbon values that reflect the Interagency Working Group values minus the assumed CO_2 allowance price for that year. Table H-4 shows the present value of the global social costs of CO_2 emissions for each resource case under each of the discount rate cases provided by the Interagency Working Group.

Table H-4. Present Values of the Social Costs of Carbon by Discount Rate, 2022-2051 (2022$ Millions)

Discount	**5%**	**3%**	**2.5%**	**3%**
Pct. Distr.	**Avg**	**Avg**	**Avg**	**95th**
Net-Zero	$458	$5,569	$9,866	$25,754
Iron_Hot	$458	$6,140	$11,016	$29,280
Repower Valmy	$462	$6,123	$10,955	$28,979
Geo	$458	$5,553	$9,833	$25,649

Note: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 based on values reported in Interagency Working Group (2021) and the allowance price projections for the Mid CO_2 Price scenario.

Source: NERA calculations as explained in text.

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XVII. Appendix I: Overview of the REMI PI+ Model

This overview is based on text prepared by Regional Economic Models, Inc. More detailed information is available from REMI PI+.[29]

REMI PI+ is a structural economic forecasting and policy analysis model. It integrates input-output, computable general equilibrium, econometric, and economic geography methodologies. The model is dynamic, with forecasts and simulations generated on an annual basis and behavioral responses to compensation, price, and other economic factors.

The model consists of thousands of simultaneous equations with a structure that is relatively straightforward. The exact number of equations used varies depending on the extent of industry, demographic, demand, and other detail in the specific model being used. The overall structure of the model can be summarized in five major blocks: (1) Output and Demand, (2) Labor and Capital Demand, (3) Population and Labor Supply, (4) Compensation, Prices, and Costs, and (5) Market Shares.

The Output and Demand block consists of output, demand, consumption, investment, government spending, exports, and imports, as well as feedback from output change due to the change in the productivity of intermediate inputs. The Labor and Capital Demand block includes labor intensity and productivity as well as demand for labor and capital. Labor force participation rate and migration equations are in the Population and Labor Supply block. The Compensation, Prices, and Costs block includes composite prices, determinants of production costs, the consumption price deflator, housing prices, and the compensation equations. The proportion of local, inter-regional, and export markets captured by each region is included in the Market Shares block.

Models can be built as single region, multi-region, or multi-region national models. A region is defined broadly as a sub-national area, and could consist of a state, province, county, or city, or any combination of sub-national areas.

Single-region models consist of an individual region, called the home region. The rest of the nation is also represented in the model. However, since the home region is only a small part of the total nation, the changes in the region do not have an endogenous effect on the variables in the rest of the nation.

Multiregional national models also include a central bank monetary response that constrains labor markets. Models that only encompass a relatively small portion of a nation are not endogenously constrained by changes in exchange rates or monetary responses.

The following sub-sections describe the five blocks of the REMI PI+ model in more depth.

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[29] See https://www.remi.com/wp-content/uploads/2020/10/PI-Model-Overview.pdf.

A. Block 1: Output and Demand

This block includes output, demand, consumption, investment, government spending, import, commodity access, and export concepts. Output for each industry in the home region is determined by industry demand in all regions in the nation, the home region's share of each market, and international exports from the region.

For each industry, demand is determined by the amount of output, consumption, investment, and capital demand on that industry. Consumption depends on real disposable income per capita, relative prices, differential income elasticities, and population. Input productivity depends on access to inputs because a larger choice set of inputs means it is more likely that the input with the specific characteristics required for the job will be found. In the capital stock adjustment process, investment occurs to fill the difference between optimal and actual capital stock for residential, non-residential, and equipment investment. Government spending changes are determined by changes in the population.

B. Block 2: Labor and Capital Demand

The Labor and Capital Demand block includes the determination of labor productivity, labor intensity, and the optimal capital stocks. Industry-specific labor productivity depends on the availability of workers with differentiated skills for the occupations used in each industry. The occupational labor supply and commuting costs determine firms' access to a specialized labor force.

Labor intensity is determined by the cost of labor relative to the other factor inputs, capital and fuel. Demand for capital is driven by the optimal capital stock equation for both non-residential capital and equipment. Optimal capital stock for each industry depends on the relative cost of labor and capital, and the employment weighted by capital use for each industry. Employment in private industries is determined by the value added and employment per unit of value added in each industry.

C. Block 3: Population and Labor Supply

The Population and Labor Supply block includes detailed demographic information about the region. Population data is given for age, gender, and ethnic category, with birth and survival rates for each group. The size and labor force participation rate of each group determines the labor supply. These participation rates respond to changes in employment relative to the potential labor force and to changes in the real after-tax compensation rate. Migration includes retirement, military, international, and economic migration. Economic migration is determined by the relative real after-tax compensation rate, relative employment opportunity, and consumer access to variety.

D. Block 4: Compensation, Prices, and Costs

This block includes delivered prices, production costs, equipment cost, the consumption deflator, consumer prices, the price of housing, and the compensation equation. Economic geography concepts account for the productivity and price effects of access to specialized labor, goods, and services.

These prices measure the price of the industry output, considering the access to production locations. This access is important due to the specialization of production that takes place within each industry, and because transportation and transaction costs of distance are significant. Composite prices for each industry are then calculated based on the production costs of supplying regions, the effective distance to these regions, and the index of access to the variety of outputs in the industry relative to the access by other uses of the product.

The cost of production for each industry is determined by the cost of labor, capital, fuel, and intermediate inputs. Labor costs reflect a productivity adjustment to account for access to specialized labor, as well as underlying compensation rates. Capital costs include costs of non-residential structures and equipment, while fuel costs incorporate electricity, natural gas, and residual fuels.

The consumption deflator converts industry prices to prices for consumption commodities. For potential migrants, the consumer price is additionally calculated to include housing prices. Housing prices change from their initial level depending on changes in income and population density.

Compensation changes are due to changes in labor demand and supply conditions and changes in the national compensation rate. Changes in employment opportunities relative to the labor force and occupational demand change determine compensation rates by industry.

E. Block 5: Market Shares

The equations in the Market Shares block measure the proportion of local and export markets that are captured by each industry. These depend on relative production costs, the estimated price elasticity of demand, and the effective distance between the home region and each of the other regions. The change in share of a specific area in any region depends on changes in its delivered price and the quantity it produces compared with the same factors for competitors in that market. The share of local and external markets then drives the exports from and imports to the home economy.

XVIII. Appendix J: Expenditures and Electricity Revenues

This appendix presents estimates of the expenditures and electricity revenues that are used in the REMI economic impact modeling. The REMI modeling for the various cases requires estimates of the additional expenditures and electricity revenues relative to a case that is presumed to be consistent with the REMI reference case. NV Energy developed the Base case to be as consistent with the REMI reference forecast as possible, involving the least changes to NV Energy's generation fleet (and thus seem to most closely approximate what resources might be implicit in REMI's reference scenario). We model the changes from this baseline for all cases.

The following tables provide the estimates of annual expenditures and annual revenue requirements that are used in the REMI modeling. These estimates incorporate the assumption that 50 percent of expenditures related to NV Energy's open position are incurred outside Nevada and thus are not included in the REMI modeling. The tables also provide information on the data sources used to translate the expenditure and revenue requirements into REMI variables. As noted below, a consistent source of information is used to develop estimates of the sectors in which expenditures would be made for new generation facilities (including fossil fuel and renewable) and new transmission facilities.

A. Annual Expenditures

1. Construction Expenditures

Table J-1. Construction Expenditures by Year (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	$444	$589	$586	$589	$589
2023	$1,710	$1,857	$1,270	$1,857	$1,857
2024	$3,752	$3,745	$2,923	$3,745	$3,745
2025	$29	$22	$54	$21	$21
2026	$30	$24	$36	$22	$22
2027	$385	$378	$501	$351	$351
2028	$162	$155	$873	$162	$162
2029	$684	$676	$2,047	$95	$95
2030	$1,199	$1,191	$1,553	$1,407	$1,231
2031	$818	$810	$717	$1,391	$1,746
2032	$853	$843	$962	$1,518	$1,366
2033	$2,074	$2,064	$1,569	$2,043	$2,393
2034	$777	$767	$974	$2,124	$2,128
2035	$154	$144	$656	$881	$1,075
2036	$1,103	$1,092	$116	$2,113	$2,112
2037	$442	$431	$800	$1,823	$1,844
2038	$3,610	$3,599	$1,668	$2,328	$2,363
2039	$1,115	$1,104	$1,213	$2,083	$1,892
2040	$3,025	$3,016	$3,256	$2,239	$2,431
2041	$1,923	$1,914	$1,076	$1,968	$2,090
2042	$910	$904	$328	$2,021	$1,906
2043	$107	$101	$1,977	$1,599	$1,708
2044	$2,260	$2,256	$5,070	$2,955	$2,995
2045	$196	$193	$180	$1,654	$1,913
2046	$3,086	$3,083	$1,082	$7,247	$4,207
2047	$1,748	$1,748	$1,685	$3,248	$3,608
2048	$192	$192	$241	$1,631	$1,430
2049	$2,752	$2,752	$5,271	$3,317	$3,168
2050	$3,857	$3,857	$4,291	$1,584	$1,150
2051	$159	$159	$160	$121	$136

Source: NERA calculations as explained in text.

Table J-2. Construction Expenditures by Year, Relative to the Base Case (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	-	$145	$143	$145	$145
2023	-	$147	-$440	$147	$147
2024	-	-$7	-$829	-$7	-$7
2025	-	-$7	$25	-$8	-$8
2026	-	-$7	$6	-$8	-$8
2027	-	-$7	$116	-$34	-$34
2028	-	-$7	$711	$0	$0
2029	-	-$7	$1,363	-$589	-$589
2030	-	-$8	$354	$209	$32
2031	-	-$9	-$101	$573	$928
2032	-	-$10	$110	$665	$514
2033	-	-$10	-$505	-$30	$319
2034	-	-$10	$197	$1,347	$1,351
2035	-	-$11	$502	$727	$921
2036	-	-$11	-$987	$1,009	$1,009
2037	-	-$11	$358	$1,381	$1,402
2038	-	-$11	-$1,942	-$1,282	-$1,247
2039	-	-$12	$98	$968	$777
2040	-	-$9	$231	-$786	-$594
2041	-	-$9	-$847	$45	$167
2042	-	-$6	-$582	$1,111	$996
2043	-	-$6	$1,870	$1,492	$1,601
2044	-	-$4	$2,810	$695	$736
2045	-	-$4	-$16	$1,458	$1,716
2046	-	-$4	-$2,004	$4,161	$1,121
2047	-	$0	-$63	$1,500	$1,860
2048	-	$0	$49	$1,439	$1,238
2049	-	$0	$2,519	$565	$416
2050	-	$0	$433	-$2,273	-$2,707
2051	-	$0	$1	-$38	-$22

Source: NERA calculations as explained in text.

2. Fuel Expenditures

Table J-3. Fuel Expenditures by Year (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	$680	$677	$677	$677	$677
2023	$567	$562	$563	$562	$562
2024	$492	$484	$497	$484	$484
2025	$454	$447	$476	$447	$447
2026	$458	$450	$491	$450	$450
2027	$473	$467	$504	$468	$468
2028	$501	$497	$520	$494	$494
2029	$510	$507	$520	$513	$513
2030	$507	$504	$505	$509	$517
2031	$514	$508	$507	$498	$497
2032	$505	$502	$499	$477	$477
2033	$519	$516	$522	$478	$481
2034	$537	$530	$515	$467	$467
2035	$551	$550	$528	$468	$466
2036	$542	$539	$523	$438	$440
2037	$567	$564	$538	$440	$441
2038	$576	$582	$552	$429	$438
2039	$597	$587	$558	$382	$374
2040	$597	$580	$518	$375	$370
2041	$611	$593	$535	$369	$369
2042	$480	$480	$458	$475	$475
2043	$487	$485	$462	$461	$463
2044	$413	$410	$403	$376	$386
2045	$418	$416	$409	$374	$383
2046	$429	$428	$426	$385	$393
2047	$370	$370	$366	$310	$313
2048	$394	$394	$387	$312	$317
2049	$380	$380	$371	$322	$324
2050	$381	$381	$382	$329	$333
2051	$380	$380	$381	$328	$333

Source: NERA calculations as explained in text.

Table J-4. Fuel Expenditures by Year, Relative to the Base Case (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	-	-$2	-$2	-$2	-$2
2023	-	-$5	-$5	-$5	-$5
2024	-	-$8	$5	-$8	-$8
2025	-	-$7	$23	-$7	-$7
2026	-	-$8	$33	-$8	-$8
2027	-	-$7	$30	-$5	-$5
2028	-	-$4	$19	-$7	-$7
2029	-	-$4	$9	$3	$3
2030	-	-$3	-$1	$2	$10
2031	-	-$7	-$8	-$17	-$17
2032	-	-$3	-$5	-$27	-$28
2033	-	-$3	$2	-$41	-$38
2034	-	-$7	-$22	-$70	-$70
2035	-	-$1	-$24	-$84	-$85
2036	-	-$2	-$19	-$103	-$101
2037	-	-$3	-$29	-$127	-$126
2038	-	$5	-$25	-$147	-$139
2039	-	-$10	-$39	-$215	-$223
2040	-	-$16	-$78	-$222	-$226
2041	-	-$18	-$76	-$242	-$242
2042	-	$0	-$22	-$5	-$5
2043	-	-$2	-$25	-$26	-$24
2044	-	-$2	-$10	-$36	-$27
2045	-	-$2	-$8	-$44	-$34
2046	-	-$1	-$3	-$45	-$37
2047	-	$0	-$4	-$60	-$56
2048	-	$0	-$7	-$82	-$77
2049	-	$0	-$9	-$58	-$56
2050	-	$0	$1	-$53	-$48
2051	-	$0	$1	-$52	-$48

Source: NERA calculations as explained in text.

3. Non-Fuel O&M Expenditures

Table J-5. Non-Fuel O&M Expenditures by Year (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	$213	$215	$215	$215	$215
2023	$221	$226	$225	$226	$226
2024	$275	$282	$273	$282	$282
2025	$306	$313	$294	$313	$313
2026	$303	$311	$301	$311	$311
2027	$309	$317	$311	$317	$317
2028	$306	$314	$320	$314	$314
2029	$308	$317	$344	$307	$307
2030	$305	$313	$347	$319	$304
2031	$317	$325	$358	$339	$330
2032	$321	$330	$367	$356	$345
2033	$321	$331	$360	$359	$353
2034	$345	$354	$370	$402	$396
2035	$348	$357	$383	$432	$416
2036	$361	$371	$385	$469	$453
2037	$372	$382	$397	$503	$487
2038	$419	$429	$408	$538	$524
2039	$430	$439	$425	$564	$547
2040	$456	$466	$458	$599	$571
2041	$498	$507	$465	$633	$607
2042	$502	$513	$476	$669	$640
2043	$512	$521	$514	$704	$677
2044	$548	$555	$593	$753	$728
2045	$552	$559	$598	$801	$764
2046	$589	$597	$604	$909	$830
2047	$590	$598	$604	$948	$862
2048	$595	$603	$610	$983	$892
2049	$601	$610	$674	$1,008	$913
2050	$588	$597	$694	$986	$865
2051	$598	$608	$706	$1,005	$881

Source: NERA calculations as explained in text.

Table J-6. Non-Fuel O&M Expenditures by Year, Relative to the Base Case (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	-	$2	$2	$2	$2
2023	-	$5	$5	$5	$5
2024	-	$7	-$3	$7	$7
2025	-	$7	-$12	$7	$7
2026	-	$8	-$2	$8	$8
2027	-	$8	$2	$8	$8
2028	-	$8	$14	$8	$8
2029	-	$8	$36	-$1	-$1
2030	-	$8	$42	$14	-$1
2031	-	$8	$41	$23	$14
2032	-	$9	$45	$35	$23
2033	-	$9	$38	$37	$32
2034	-	$9	$24	$57	$51
2035	-	$10	$35	$84	$68
2036	-	$10	$24	$108	$92
2037	-	$10	$25	$130	$114
2038	-	$10	-$11	$120	$105
2039	-	$10	-$5	$134	$117
2040	-	$10	$2	$144	$115
2041	-	$9	-$33	$135	$109
2042	-	$11	-$26	$167	$138
2043	-	$9	$2	$192	$165
2044	-	$8	$46	$206	$180
2045	-	$8	$46	$250	$212
2046	-	$8	$15	$320	$241
2047	-	$8	$15	$358	$273
2048	-	$9	$15	$388	$297
2049	-	$9	$73	$407	$312
2050	-	$9	$106	$398	$277
2051	-	$9	$108	$407	$283

Source: NERA calculations as explained in text.

4. Total Expenditures

Table J-7. Total Expenditures by Year (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	$1,336	$1,481	$1,478	$1,481	$1,481
2023	$2,498	$2,645	$2,058	$2,645	$2,645
2024	$4,520	$4,511	$3,692	$4,511	$4,511
2025	$789	$783	$824	$781	$781
2026	$791	$785	$828	$783	$783
2027	$1,167	$1,162	$1,316	$1,136	$1,136
2028	$969	$965	$1,714	$970	$970
2029	$1,503	$1,500	$2,911	$916	$916
2030	$2,011	$2,009	$2,405	$2,236	$2,053
2031	$1,649	$1,643	$1,582	$2,228	$2,573
2032	$1,679	$1,676	$1,828	$2,352	$2,188
2033	$2,914	$2,910	$2,450	$2,880	$3,227
2034	$1,659	$1,651	$1,859	$2,993	$2,991
2035	$1,053	$1,051	$1,567	$1,781	$1,957
2036	$2,006	$2,002	$1,024	$3,019	$3,006
2037	$1,381	$1,378	$1,735	$2,766	$2,772
2038	$4,605	$4,609	$2,627	$3,295	$3,324
2039	$2,142	$2,130	$2,196	$3,029	$2,813
2040	$4,077	$4,062	$4,232	$3,213	$3,372
2041	$3,033	$3,015	$2,076	$2,970	$3,066
2042	$1,892	$1,898	$1,262	$3,165	$3,021
2043	$1,106	$1,108	$2,953	$2,764	$2,848
2044	$3,220	$3,222	$6,066	$4,085	$4,109
2045	$1,166	$1,168	$1,187	$2,829	$3,060
2046	$4,105	$4,108	$2,113	$8,541	$5,429
2047	$2,708	$2,716	$2,656	$4,505	$4,784
2048	$1,181	$1,190	$1,238	$2,927	$2,639
2049	$3,733	$3,742	$6,316	$4,647	$4,405
2050	$4,827	$4,836	$5,367	$2,900	$2,348
2051	$1,137	$1,146	$1,248	$1,454	$1,350

Source: NERA calculations as explained in text.

Table J-8. Total Expenditures by Year, Relative to the Base Case (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	-	$144	$142	$144	$144
2023	-	$147	-$440	$147	$147
2024	-	-$8	-$828	-$8	-$8
2025	-	-$6	$36	-$7	-$7
2026	-	-$6	$37	-$8	-$8
2027	-	-$6	$148	-$32	-$32
2028	-	-$4	$745	$1	$1
2029	-	-$3	$1,408	-$587	-$587
2030	-	-$2	$394	$225	$42
2031	-	-$7	-$67	$579	$924
2032	-	-$3	$149	$673	$509
2033	-	-$4	-$464	-$34	$313
2034	-	-$8	$200	$1,334	$1,332
2035	-	-$2	$513	$727	$904
2036	-	-$4	-$982	$1,014	$1,000
2037	-	-$4	$354	$1,385	$1,391
2038	-	$4	-$1,978	-$1,310	-$1,281
2039	-	-$12	$55	$887	$671
2040	-	-$15	$154	-$864	-$705
2041	-	-$18	-$957	-$62	$33
2042	-	$6	-$630	$1,273	$1,129
2043	-	$2	$1,846	$1,658	$1,742
2044	-	$2	$2,846	$865	$889
2045	-	$2	$22	$1,664	$1,894
2046	-	$3	-$1,992	$4,436	$1,325
2047	-	$8	-$51	$1,798	$2,076
2048	-	$9	$57	$1,746	$1,458
2049	-	$9	$2,583	$914	$672
2050	-	$9	$540	-$1,927	-$2,479
2051	-	$9	$110	$317	$213

Source: NERA calculations as explained in text.

B. Annual Electricity Revenue Requirements

Table J-9. Electricity Revenue Requirements by Year (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	$1,379	$1,370	$1,370	$1,370	$1,370
2023	$1,319	$1,319	$1,319	$1,319	$1,319
2024	$1,372	$1,386	$1,377	$1,386	$1,386
2025	$1,492	$1,506	$1,472	$1,503	$1,503
2026	$1,507	$1,521	$1,494	$1,518	$1,518
2027	$1,576	$1,584	$1,580	$1,579	$1,579
2028	$1,617	$1,617	$1,639	$1,620	$1,620
2029	$1,683	$1,683	$1,719	$1,673	$1,673
2030	$1,725	$1,722	$1,756	$1,725	$1,704
2031	$1,773	$1,770	$1,803	$1,782	$1,770
2032	$1,924	$1,915	$1,941	$1,938	$1,930
2033	$1,924	$1,916	$1,925	$1,956	$1,945
2034	$2,024	$2,018	$2,034	$2,070	$2,067
2035	$2,202	$2,185	$2,205	$2,250	$2,227
2036	$2,307	$2,292	$2,299	$2,379	$2,365
2037	$2,448	$2,427	$2,420	$2,522	$2,516
2038	$2,523	$2,503	$2,471	$2,629	$2,632
2039	$2,668	$2,648	$2,631	$2,753	$2,732
2040	$2,882	$2,861	$2,883	$2,953	$2,921
2041	$3,031	$3,011	$3,001	$3,087	$3,064
2042	$3,343	$3,326	$3,329	$3,450	$3,424
2043	$3,398	$3,376	$3,411	$3,566	$3,549
2044	$3,570	$3,555	$3,595	$3,649	$3,649
2045	$3,583	$3,569	$3,601	$3,699	$3,681
2046	$3,655	$3,642	$3,671	$3,803	$3,787
2047	$3,725	$3,726	$3,750	$3,970	$3,948
2048	$3,831	$3,833	$3,855	$4,034	$4,014
2049	$3,918	$3,920	$3,929	$4,113	$4,089
2050	$4,066	$4,069	$4,062	$4,406	$4,408
2051	$4,130	$4,132	$4,127	$4,446	$4,449

Source: NV Energy.

Table J-10. Electricity Revenue Requirements by Year, Relative to the Base Case (Nominal$ Millions)

	Base	Iron_Hot	Repower Valmy	Geo	Net-Zero
2022	-	-$9	-$9	-$9	-$9
2023	-	$0	-$1	$0	$0
2024	-	$14	$4	$14	$14
2025	-	$14	-$20	$11	$11
2026	-	$14	-$12	$12	$12
2027	-	$8	$4	$4	$4
2028	-	$0	$22	$3	$3
2029	-	$0	$36	-$10	-$10
2030	-	-$3	$31	$0	-$21
2031	-	-$3	$30	$9	-$2
2032	-	-$9	$18	$15	$6
2033	-	-$9	$1	$31	$20
2034	-	-$6	$10	$47	$43
2035	-	-$18	$3	$47	$25
2036	-	-$15	-$8	$72	$58
2037	-	-$21	-$27	$75	$68
2038	-	-$20	-$52	$106	$109
2039	-	-$20	-$37	$86	$65
2040	-	-$21	$1	$70	$38
2041	-	-$21	-$31	$56	$32
2042	-	-$16	-$13	$107	$81
2043	-	-$23	$13	$168	$151
2044	-	-$15	$26	$79	$79
2045	-	-$14	$17	$116	$98
2046	-	-$13	$15	$148	$132
2047	-	$1	$25	$245	$223
2048	-	$2	$24	$203	$183
2049	-	$2	$11	$195	$171
2050	-	$2	-$4	$340	$342
2051	-	$2	-$3	$316	$319

Source: NERA calculations as explained in text.

C. REMI Input Variables for Expenditures and Revenue Requirements

The expenditure and revenue requirements information are translated into REMI variables that reflect the mix of sectors that would be affected in Nevada. Determining the specific expenditure categories that would be affected is important because of the differences in Nevada-specific impacts, which can be measured by the regional purchase coefficient ("RPC"). The RPC measures the fraction of expenditures made within the state. In the case of major equipment, most of which is manufactured outside Nevada, the RPC is low and thus expenditures do not add substantially to the Nevada economy. In contrast, construction tends to have a high RPC, as most of construction expenses are paid to labor in Nevada.

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1. REMI Variables for Expenditures

a. Construction Expenditures

The cases in this year's REMI analysis include construction of new natural gas facilities, new renewable facilities, and new transmission lines. In order to accurately model differences in construction across these types of projects, we have developed a consistent set of information on the expected allocation of costs for each type of construction expenditure.

In particular, we use information on project costs from models developed by the United States Department of Energy's National Renewable Energy Laboratory ("NREL") for natural gas, solar PV, and transmission line projects. The NREL's Jobs and Economic Development Impact ("JEDI") models provide average costs and spending patterns for different types of projects developed from a number of sources, including research on existing renewable and fossil fuel resources, prior studies, and project-related case studies along with personal communications and anecdotal evidence. Project construction costs are broken out by categories, including equipment, labor and management, engineering/design, land acquisition, and other costs. For each project type, we use the percentages of total costs by category to allocate the expenditure estimates received from NV Energy to sectors in the REMI model. Note that we exclude costs in the NREL information that are not relevant for economic impacts within Nevada (e.g., land acquisition costs, which represent a transfer within the state and thus have no net impact on the state economy).

Table J-11 shows the REMI variables we use for construction expenditures for different types of projects. Expenditures are modeled in REMI as increases in final demand in those sectors.

Table J-11. Allocation of NV Energy Construction Expenditures to REMI Model Sectors

REMI Sectors	New Fossil Generation	New Transmission	Renewable Generation	Renewable Purchases	Open Position	Financing	Repower Valmy	Geothermal	Wind
Construction	28.4%	32.1%	16.1%	16.1%	28.4%	0.0%	26.6%	7.7%	17.6%
Electric power generation, transmission, and distribution	2.5%	0.0%	0.0%	0.0%	2.5%	0.0%	0.0%	0.0%	0.0%
Electrical equipment manufacturing	54.3%	24.9%	43.5%	43.5%	54.3%	0.0%	6.3%	22.9%	3.6%
Industrial machinery manufacturing	9.3%	33.5%	12.9%	12.9%	9.3%	0.0%	52.5%	22.2%	74.9%
Architectural, engineering, and related services	5.6%	9.5%	27.4%	27.4%	5.6%	0.0%	14.6%	47.2%	1.8%
Securities, commodity contracts, and other financial investments and related activities	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	2.0%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

b. Fuel Expenditures

Fuel expenditures represent payments to extract fossil fuels (e.g. natural gas) and then transport these fuels to NV Energy's fossil facilities or to the fossil facilities from which NV Energy purchases power. Table J-12 shows the REMI variables we use for fuel expenditures. Expenditures are modeled as increases in final demand in those sectors.

Table J-12. Allocation of NV Energy Fuel Expenditures to REMI Model Sectors

REMI Sectors	Natural Gas Fuel Expenditures	Natural Gas Distribution Expenditures	Coal Fuel Expenditures
Oil and gas extraction	100.0%	0.0%	0.0%
Coal mining	0.0%	0.0%	100.0%
Natural gas distribution	0.0%	100.0%	0.0%
Total	**100%**	**100%**	**100%**

Note: We do not include fuel expenditures associated with market purchases of electricity or NV Energy's open position related to its capacity requirements.

c. Non-Fuel O&M Expenditures

Non-fuel O&M expenditures represent payments to operate and maintain generation facilities, including both fixed O&M and variable O&M. Table J-13 shows the REMI sectors we use for non-fuel in the REMI model. Expenditures are modeled as increases in final demand in those sectors.

Table J-13. Allocation of NV Energy Non-Fuel O&M Expenditures to REMI Model Sectors

REMI Sectors	Natural Gas O&M Expenditures	Coal O&M Expenditures	Coal O&M Expenditures
Commercial and industrial machinery and equipment (except automotive and electronic) repair and maintenance	100.0%	100.0%	100.0%
Total	**100%**	**100%**	**100%**

Note: We assume there are no O&M expenditures associated with market purchases of electricity or NV Energy's open position related to its capacity requirements.

2. REMI Variables for Revenue Requirements

Greater expenditures on construction, fuel and O&M may ultimately be recovered from electric utility ratepayers in the form of higher electric rates, which lead to increased utility revenue requirements and consumer electricity costs, with the resulting decreases in purchases of non-electricity goods and services. Table J-14 shows the REMI sectors we use to model the increased expenditures of different types of electricity customers (residential, commercial, and industrial).

Table J-14. Allocation of NV Energy Revenue Requirements to REMI Model Sectors

REMI Sectors	Residential electricity spending	Commercial electricity spending	Industrial electricity spending
Consumer Spending/Electricity	100.0%	0.0%	0.0%
Fuel Costs/Electricity, Commercial	0.0%	100.0%	0.0%
Fuel Costs/Electricity, Industrial	0.0%	0.0%	100.0%
Total	**100%**	**100%**	**100%**

3. REMI Inputs

The following tables present the inputs for the REMI Model, by REMI Sector for each year of the analysis period, 2022 to 2051. Note that the REMI inputs are relative to the Base case.

Table J-15. REMI Inputs for each Sector by Year for the Base Case, 2022-2051 (Nominal$)

	Consumer Spending/ Electricity	Fuel Costs/ Electricity, Commercial	Fuel Costs/ Electricity, Industrial	Oil and gas extraction	Coal mining	Construction	Electric power generation, transmission, and distribution	Electrical equipment manufacturing	Industrial machinery manufacturing	Securities, commodity contracts, and other financial investments and related activities	Architectural, engineering, and related services	Commercial and industrial machinery and equipment (except automotive and electronic) repair and maintenance
2021	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2022	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2023	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2024	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2028	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2030	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2031	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2032	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2033	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2034	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2035	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2036	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2037	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2038	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2039	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2040	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2041	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2042	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2044	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2045	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2046	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2047	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2048	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2049	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2050	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table J-16. REMI Inputs for each Sector by Year for the Iron_Hot Case, 2022-2051 (Nominal$)

	Consumer Spending/ Electricity	Fuel Costs/ Electricity, Commercial	Fuel Costs/ Electricity, Industrial	Oil and gas extraction	Coal mining	Construction	Electric power generation, transmission, and distribution	Electrical equipment manufacturing	Industrial machinery manufacturing	Securities, commodity contracts, and other financial investments and related activities	Architectural, engineering, and related services	Commercial and industrial machinery and equipment (except automotive and electronic) repair and maintenance
2022	-$5,829,233	-$2,349,912	-$697,053	-$2,259,103	-$61,205	$40,249,296	$3,543,072	$76,955,519	$13,180,227	$3,347,589	$7,794,758	$1,507,673
2023	-$1,012,386	$399,751	$834,065	-$5,304,107	$133,296	$29,032,752	$1,085,520	$68,701,976	$17,419,877	$0	$30,915,115	$5,224,357
2024	$6,123,382	$4,477,675	$3,107,634	-$8,277,028	$37,602	-$1,962,418	-$172,748	-$3,752,088	-$642,623	$0	-$380,046	$6,801,673
2025	$6,304,109	$4,549,060	$3,127,508	-$6,703,707	$0	-$1,872,658	-$164,847	-$3,580,469	-$613,230	$0	-$362,663	$7,497,918
2026	$6,973,999	$4,379,915	$2,688,362	-$7,751,423	$0	-$1,940,906	-$170,854	-$3,710,957	-$635,578	$0	-$375,880	$8,272,826
2027	$2,933,471	$2,935,260	$2,422,958	-$6,697,429	$0	-$1,965,441	-$173,014	-$3,757,867	-$643,613	$0	-$380,631	$7,838,294
2028	-$1,719,062	$715,038	$1,459,122	-$4,256,409	$0	-$2,076,247	-$182,768	-$3,969,725	-$679,898	$0	-$402,090	$7,739,803
2029	-$1,887,248	$736,726	$1,544,810	-$3,775,474	$0	-$2,117,960	-$186,440	-$4,049,479	-$693,557	$0	-$410,168	$8,243,061
2030	-$3,382,242	-$452,022	$673,135	-$2,561,676	$0	-$2,258,295	-$198,794	-$4,317,796	-$739,512	$0	-$437,346	$8,354,814
2031	-$2,963,264	-$458,977	$515,327	-$6,558,437	$0	-$2,428,692	-$213,793	-$4,643,591	-$795,311	$0	-$470,345	$8,495,001
2032	-$7,025,870	-$1,895,068	$267,929	-$2,777,667	$0	-$2,702,737	-$237,917	-$5,167,557	-$885,051	$0	-$523,417	$8,874,277
2033	-$6,511,980	-$2,093,963	-$150,692	-$3,319,498	$0	-$2,815,759	-$247,866	-$5,383,652	-$922,062	$0	-$545,305	$9,206,036
2034	-$3,547,678	-$1,746,662	-$798,420	-$6,916,806	$0	-$2,919,029	-$256,957	-$5,581,102	-$955,879	$0	-$565,305	$8,893,506
2035	-$10,958,399	-$4,921,509	-$1,906,139	-$1,318,091	$0	-$2,996,207	-$263,751	-$5,728,663	-$981,152	$0	-$580,251	$9,605,244
2036	-$9,022,357	-$4,336,410	-$1,905,609	-$2,366,818	$0	-$3,095,053	-$272,452	-$5,917,653	-$1,013,521	$0	-$599,394	$9,543,411
2037	-$12,557,497	-$5,771,754	-$2,340,443	-$2,531,669	$0	-$3,114,190	-$274,136	-$5,954,243	-$1,019,788	$0	-$603,100	$9,923,677
2038	-$12,253,562	-$5,660,036	-$2,316,875	$5,226,520	$0	-$3,229,326	-$284,272	-$6,174,380	-$1,057,491	$0	-$625,398	$10,449,225
2039	-$11,741,960	-$5,585,786	-$2,411,745	-$10,309,478	$0	-$3,284,047	-$289,089	-$6,279,006	-$1,075,410	$0	-$635,995	$9,816,509
2040	-$12,599,056	-$5,958,960	-$2,546,935	-$16,413,951	$0	-$2,493,220	-$219,474	-$4,766,967	-$816,442	$0	-$482,842	$9,941,860
2041	-$11,250,858	-$6,223,381	-$3,340,895	-$17,730,182	$0	-$2,514,452	-$221,343	-$4,807,561	-$823,394	$0	-$486,954	$8,888,144
2042	-$7,257,117	-$5,374,526	-$3,763,186	$220,454	$0	-$1,710,060	-$150,533	-$3,269,586	-$559,984	$0	-$331,174	$11,489,486
2043	-$10,903,906	-$7,125,244	-$4,531,016	-$1,969,893	$0	-$1,584,932	-$139,519	-$3,030,345	-$519,009	$0	-$306,941	$9,210,636
2044	-$10,583,550	-$3,818,252	-$735,617	-$2,333,307	$0	-$1,083,486	-$95,377	-$2,071,596	-$354,804	$0	-$209,830	$7,833,341
2045	-$9,912,918	-$3,457,362	-$548,379	-$2,089,507	$0	-$999,903	-$88,020	-$1,911,787	-$327,433	$0	-$193,643	$7,940,108
2046	-$9,662,883	-$3,194,237	-$326,562	-$952,678	$0	-$1,073,580	-$94,505	-$2,052,655	-$351,560	$0	-$207,912	$8,191,641
2047	$488,945	$457,642	$366,493	-$252	$0	$0	$0	$0	$0	$0	$0	$8,425,431
2048	$614,325	$574,884	$460,341	$0	$0	$0	$0	$0	$0	$0	$0	$8,593,939
2049	$741,787	$694,163	$555,854	$0	$0	$0	$0	$0	$0	$0	$0	$8,765,818
2050	$869,943	$814,091	$651,887	$0	$0	$0	$0	$0	$0	$0	$0	$8,941,134
2051	$870,489	$814,602	$652,297	$0	$0	$0	$0	$0	$0	$0	$0	$9,119,957

Table J-17. REMI Inputs for each Sector by Year for the Repower Valmy Case, 2022-2051 (Nominal$)

	Consumer Spending/ Electricity	Fuel Costs/ Electricity, Commercial	Fuel Costs/ Electricity, Industrial	Oil and gas extraction	Coal mining	Construction	Electric power generation, transmission, and distribution	Electrical equipment manufacturing	Industrial machinery manufacturing	Securities, commodity contracts, and other financial investments and related activities	Architectural, engineering, and related services	Commercial and industrial machinery and equipment (except automotive and electronic) repair and maintenance
2022	-$5,829,233	-$2,349,912	-$697,053	-$2,259,103	-$61,205	$39,489,435	$3,543,072	$76,366,095	$12,387,226	$3,266,355	$7,569,877	$1,507,673
2023	-$1,453,268	$185,214	$737,829	-$4,755,511	$136,251	-$65,963,119	$1,085,520	-$185,724,557	-$58,976,605	-$284,318	-$129,703,197	$4,502,298
2024	$599,494	$1,718,469	$1,817,668	$4,695,265	-$35,271	-$133,338,501	$10,119	-$362,137,682	-$105,473,256	-$93,215	-$228,338,193	-$2,827,308
2025	-$12,727,222	-$5,429,920	-$1,875,705	$22,587,924	$0	$6,473,317	$48,304	$2,456,376	$11,880,998	$1,066,725	$3,365,966	-$12,291,011
2026	-$11,027,371	-$2,425,243	$1,069,759	$33,173,755	$0	$1,142,920	-$257,080	-$4,618,645	$7,068,949	$1,137,840	$1,670,072	-$2,225,541
2027	-$3,481,095	$3,034,626	$4,830,605	$30,473,538	$0	$17,418,238	-$257,546	$49,372,705	$15,342,371	$0	$34,182,403	$1,921,514
2028	$5,517,953	$8,252,840	$7,787,072	$19,336,481	$0	$112,803,088	-$349,033	$307,910,458	$92,261,132	$0	$198,680,746	$14,103,166
2029	$2,489,897	$15,913,959	$17,925,718	$9,259,146	$0	$217,040,571	-$500,733	$590,907,123	$176,597,072	$0	$379,335,940	$35,835,551
2030	$3,930,671	$12,912,695	$13,863,005	-$1,401,731	$0	$53,353,851	-$734,542	$150,745,983	$46,702,746	$0	$103,769,214	$41,735,541
2031	$4,997,691	$12,360,944	$12,829,728	-$7,656,242	$0	-$20,460,476	-$856,325	-$47,597,463	-$11,784,961	$0	-$20,216,039	$41,265,338
2032	-$3,064,672	$8,947,378	$11,672,431	-$5,340,625	$0	$12,485,480	-$1,047,279	$43,131,474	$15,640,469	$0	$39,343,239	$45,120,250
2033	-$13,045,737	$4,149,364	$9,563,363	$2,450,770	$0	-$86,428,933	-$1,040,340	-$224,184,025	-$63,651,288	$0	-$129,729,342	$38,490,299
2034	$3,831,840	$3,364,567	$2,609,775	-$21,566,881	$0	$29,571,355	-$450,264	$83,938,052	$26,117,188	$0	$58,256,292	$24,482,895
2035	-$1,032,397	$1,483,592	$2,122,608	-$23,810,235	$0	$70,264,824	-$2,228,362	$209,841,418	$68,292,438	-$2,409,506	$158,353,687	$35,078,712
2036	-$7,352,414	-$1,558,178	$782,811	-$18,772,798	$0	-$192,307,496	-$7,256,038	-$454,478,930	-$115,032,080	-$14,458,872	-$203,644,642	$24,416,239
2037	-$19,513,915	-$6,841,681	-$1,121,766	-$28,628,994	$0	$45,252,096	-$2,932,335	$148,577,310	$52,040,043	-$12,686,426	$127,741,035	$24,690,802
2038	-$35,312,458	-$13,608,764	-$3,481,823	-$24,515,083	$0	-$281,890,124	$6,756,569	-$822,256,420	-$262,226,881	$15,043,010	-$597,727,503	-$11,009,720
2039	-$25,010,835	-$9,428,588	-$2,217,656	-$39,018,131	$0	$24,112,765	$2,122,603	$46,102,927	$7,896,081	$13,198,957	$4,669,726	-$4,553,301
2040	-$1,907,930	$920,966	$1,770,017	-$78,186,541	$0	$6,802,110	-$6,586,351	$77,478,807	$40,898,617	-$12,990,458	$124,928,299	$2,032,731
2041	-$19,004,214	-$8,511,358	-$3,277,760	-$76,436,510	$0	-$126,432,255	$2,009,947	-$359,638,272	-$112,120,624	-$481,928	-$250,534,300	-$32,961,739
2042	-$16,169,361	-$1,293,560	$4,243,545	-$22,087,556	$0	-$75,565,658	$4,240,831	-$242,221,766	-$83,371,021	$16,774,605	-$202,029,866	-$26,056,177
2043	$1,518,067	$5,465,043	$5,919,194	-$25,325,911	$0	$297,632,523	-$705,015	$810,488,619	$242,270,215	$0	$520,507,409	$1,567,374
2044	-$3,442,302	$12,710,427	$16,256,215	-$9,815,625	$0	$450,469,519	-$399,676	$1,220,693,450	$363,086,308	$0	$776,311,439	$45,716,378
2045	-$6,283,323	$9,861,103	$13,901,849	-$8,476,216	$0	-$4,631,131	-$407,670	-$8,854,592	-$1,516,532	$0	-$896,874	$46,447,048
2046	-$3,757,351	$8,102,526	$10,920,889	-$2,769,829	$0	-$323,982,865	-$256,739	-$873,053,664	-$258,206,955	$0	-$548,970,006	$15,464,316
2047	$19,488,871	$5,733,102	-$179,938	-$3,505,537	$0	-$11,112,611	-$200,824	-$28,222,732	-$7,823,037	$0	-$15,526,251	$14,902,026
2048	$19,298,626	$5,335,508	-$582,081	-$7,217,036	$0	$6,997,363	-$176,982	$20,494,007	$6,559,119	$0	$14,996,767	$15,276,090
2049	$5,831,383	$3,167,347	$1,662,718	-$9,055,949	$0	$404,018,811	-$315,913	$1,094,438,358	$325,417,214	$0	$695,529,120	$73,066,769
2050	-$6,134,675	-$76,852	$2,099,381	$690,740	$0	$69,822,951	$15,344	$188,514,384	$55,862,512	$0	$118,998,824	$105,790,694
2051	-$5,837,067	$218,694	$2,342,543	$1,095,161	$0	$395,106	$34,780	$755,432	$129,383	$0	$76,517	$107,939,069

Table J-18. REMI Inputs for each Sector by Year for the Geo Case, 2022-2051 (Nominal$)

	Consumer Spending/ Electricity	Fuel Costs/ Electricity, Commercial	Fuel Costs/ Electricity, Industrial	Oil and gas extraction	Coal mining	Construction	Electric power generation, transmission, and distribution	Electrical equipment manufacturing	Industrial machinery manufacturing	Securities, commodity contracts, and other financial investments and related activities	Architectural, engineering, and related services	Commercial and industrial machinery and equipment (except automotive and electronic) repair and maintenance
2022	-$5,829,233	-$2,349,912	-$697,053	-$2,259,103	-$61,205	$40,249,296	$3,543,072	$76,955,519	$13,180,227	$3,347,589	$7,794,758	$1,507,673
2023	-$1,012,386	$399,751	$834,065	-$5,304,107	$133,296	$29,032,752	$1,085,520	$68,701,976	$17,419,877	$0	$30,915,115	$5,224,357
2024	$6,123,382	$4,477,675	$3,107,634	-$8,277,028	$37,602	-$1,962,418	-$172,748	-$3,752,088	-$642,623	$0	-$380,046	$6,801,673
2025	$4,389,762	$3,792,041	$2,915,974	-$6,703,707	$0	-$2,282,030	-$200,883	-$4,363,176	-$747,284	$0	-$441,942	$7,497,918
2026	$5,320,938	$3,753,699	$2,538,189	-$7,741,114	$0	-$2,285,553	-$201,193	-$4,369,912	-$748,438	$0	-$442,625	$8,273,223
2027	-$131,066	$1,720,622	$2,081,043	-$5,349,261	$0	-$6,447,909	-$205,405	-$15,578,237	-$4,060,825	$0	-$7,479,779	$7,542,829
2028	$145,170	$1,377,802	$1,577,112	-$7,122,347	$0	-$1,073,249	-$217,622	-$947,016	$311,332	$0	$1,910,714	$7,877,158
2029	-$6,807,548	-$2,362,919	-$363,145	$2,894,401	$0	-$95,570,412	-$157,555	-$256,804,426	-$75,727,072	$0	-$160,530,853	-$1,082,006
2030	-$3,717,509	$1,011,438	$2,523,047	$2,375,225	$0	$4,335,098	-$188,575	$20,225,884	$58,455,736	$0	$125,735,836	$13,819,808
2031	$2,264,356	$3,534,858	$3,370,740	-$16,721,632	$0	$90,887,067	-$373,386	$247,038,168	$75,068,309	$117,292	$160,289,632	$22,640,093
2032	$5,841,042	$4,935,025	$3,749,151	-$27,288,189	$0	$101,426,174	-$1,277,646	$283,589,946	$88,384,243	-$604,884	$193,820,350	$34,723,961
2033	$13,473,411	$10,414,708	$7,502,686	-$41,445,712	$0	-$14,823,386	$3,601,750	-$171,103,612	$227,020,266	-$5,037,539	-$69,888,517	$37,389,071
2034	$30,385,959	$12,428,126	$3,844,875	-$69,860,543	$0	$206,289,769	-$2,621,493	$574,915,099	$180,149,056	-$4,742,692	$393,077,480	$56,592,388
2035	$34,822,928	$11,297,691	$924,274	-$83,815,454	$0	$75,357,325	-$2,548,543	$225,878,870	$134,702,783	-$298,243	$293,668,512	$84,222,217
2036	$49,656,096	$18,200,143	$3,789,038	-$103,356,473	$0	$125,748,414	-$9,095,903	$399,272,246	$152,491,211	-$14,106,807	$355,067,599	$107,541,002
2037	$50,853,711	$19,180,204	$4,520,161	-$127,281,870	$0	$186,214,294	-$8,143,560	$574,790,110	$193,209,601	-$21,742,901	$457,134,494	$130,460,207
2038	$71,353,453	$27,652,963	$7,218,342	-$147,282,337	$0	-$261,135,886	-$12,216,732	-$600,960,802	-$142,848,341	-$25,683,282	-$239,553,956	$119,956,324
2039	$62,246,112	$21,001,974	$2,606,605	-$215,043,598	$0	$102,571,569	-$12,103,122	$379,141,083	$148,155,090	-$28,201,426	$378,582,516	$134,196,380
2040	$44,592,592	$19,123,126	$6,688,063	-$221,680,048	$0	-$183,419,426	-$5,156,216	-$449,215,753	-$52,391,363	-$5,721,259	-$90,326,636	$143,656,671
2041	$39,574,302	$13,871,879	$2,271,307	-$242,385,686	$0	$44,317,503	$6,624,935	$35,128,389	$3,019,433	$12,731,154	-$56,724,999	$134,991,472
2042	$80,095,719	$25,565,478	$1,629,141	-$5,245,169	$0	$225,139,460	$11,434,136	$526,696,805	$116,208,844	$28,684,834	$203,241,783	$166,920,589
2043	$117,739,044	$42,215,727	$7,874,655	-$26,193,014	$0	$237,565,901	-$546,201	$646,771,752	$193,287,547	$0	$415,176,953	$191,892,544
2044	$60,628,927	$18,438,150	$152,838	-$36,213,582	$0	$112,618,202	$136,253	$303,056,369	$89,501,129	$0	$190,016,218	$205,721,994
2045	$70,867,244	$32,137,061	$12,693,370	-$43,771,447	$0	$187,429,996	-$1,947,450	$533,065,095	$233,291,153	-$2,655,098	$508,539,701	$249,826,236
2046	$100,342,343	$38,169,126	$9,301,542	-$44,552,427	$0	$632,941,700	-$8,033,721	$1,782,209,913	$550,378,009	-$15,932,611	$1,219,321,545	$319,890,011
2047	$170,738,089	$62,181,898	$12,558,103	-$60,012,232	$0	$216,116,033	-$5,693,319	$635,003,093	$203,803,371	-$16,741,871	$467,088,591	$357,998,722
2048	$157,981,514	$46,570,144	-$1,344,850	-$81,517,422	$0	$228,749,216	-$599,772	$623,430,982	$186,511,575	$0	$401,039,030	$388,377,826
2049	$138,284,643	$48,628,480	$8,120,972	-$57,878,690	$0	$87,462,786	-$703,700	$242,626,914	$73,866,270	$0	$161,499,220	$407,404,965
2050	$220,040,115	$90,949,592	$28,967,307	-$52,575,949	$0	-$412,774,748	-$959,874	-$1,096,512,324	-$245,373,788	$0	-$517,523,451	$398,387,567
2051	$205,590,078	$84,188,761	$26,133,189	-$52,258,721	$0	-$10,786,407	-$949,508	-$20,623,306	-$3,532,168	$0	-$2,088,917	$407,109,726

Table J-19. REMI Inputs for each Sector by Year for the Net-Zero Case, 2022-2051 (Nominal$)

	Consumer Spending/ Electricity	Fuel Costs/ Electricity, Commercial	Fuel Costs/ Electricity, Industrial	Oil and gas extraction	Coal mining	Construction	Electric power generation, transmission, and distribution	Electrical equipment manufacturing	Industrial machinery manufacturing	Securities, commodity contracts, and other financial investments and related activities	Architectural, engineering, and related services	Commercial and industrial machinery and equipment (except automotive and electronic) repair and maintenance
2022	-$5,829,233	-$2,349,912	-$697,053	-$2,259,103	-$61,205	$40,249,296	$3,543,072	$76,955,519	$13,180,227	$3,347,589	$7,794,758	$1,507,673
2023	-$1,012,386	$399,751	$834,065	-$5,304,107	$133,296	$29,032,752	$1,085,520	$68,701,976	$17,419,877	$0	$30,915,115	$5,224,357
2024	$6,123,382	$4,477,675	$3,107,634	-$8,277,028	$37,602	-$1,962,418	-$172,748	-$3,752,088	-$642,623	$0	-$380,046	$6,801,673
2025	$4,389,762	$3,792,041	$2,915,974	-$6,703,707	$0	-$2,282,030	-$200,883	-$4,363,176	-$747,284	$0	-$441,942	$7,497,918
2026	$5,320,938	$3,753,699	$2,538,189	-$7,741,114	$0	-$2,285,553	-$201,193	-$4,369,912	-$748,438	$0	-$442,625	$8,273,223
2027	-$131,066	$1,720,622	$2,081,043	-$5,349,261	$0	-$6,447,909	-$205,405	-$15,578,237	-$4,060,825	$0	-$7,479,779	$7,542,829
2028	$145,170	$1,377,802	$1,577,112	-$7,122,347	$0	-$1,073,249	-$217,622	-$947,016	$311,332	$0	$1,910,714	$7,877,158
2029	-$6,806,533	-$2,363,718	-$364,453	$2,895,780	$0	-$95,570,412	-$157,555	-$256,804,426	-$75,727,072	$0	-$160,530,853	-$1,081,802
2030	-$13,344,401	-$5,906,198	-$2,218,447	$10,440,427	$0	$4,318,153	-$167,210	$13,167,457	$4,359,827	$0	$10,252,354	-$626,751
2031	-$921,608	-$790,965	-$606,100	-$17,403,895	$0	$147,711,817	-$438,628	$401,156,307	$120,949,839	$117,292	$258,472,948	$13,523,334
2032	$1,511,177	$2,494,235	$2,409,341	-$28,155,084	$0	$79,734,779	$2,306,422	$144,943,133	$181,873,520	-$604,884	$105,338,484	$23,318,254
2033	$4,894,803	$7,856,320	$7,540,758	-$38,220,416	$0	$41,219,812	$3,463,721	-$17,021,553	$268,800,470	-$5,037,539	$27,908,210	$31,633,898
2034	$26,805,207	$11,684,331	$4,243,927	-$69,576,065	$0	$206,984,954	-$2,605,870	$576,653,205	$180,621,982	-$4,742,692	$393,996,132	$50,720,856
2035	$20,354,071	$5,471,413	-$798,226	-$85,209,620	$0	$137,420,627	-$2,638,095	$386,838,149	$125,328,200	-$298,243	$274,152,581	$68,261,629
2036	$35,849,715	$16,066,266	$6,195,451	-$101,177,855	$0	$125,245,710	-$9,187,569	$398,736,543	$152,581,780	-$14,106,807	$355,785,941	$91,854,060
2037	$41,545,055	$18,987,135	$7,615,335	-$125,567,687	$0	$189,526,882	-$8,142,132	$583,727,457	$195,856,101	-$21,742,901	$462,768,077	$114,498,015
2038	$67,301,050	$30,128,983	$11,592,495	-$138,892,944	$0	-$255,394,318	-$12,204,606	-$585,556,673	-$138,313,214	-$25,683,282	-$229,955,531	$105,321,126
2039	$46,211,278	$16,030,881	$2,454,265	-$223,479,463	$0	$71,409,811	-$12,179,485	$295,631,491	$123,597,968	-$28,201,426	$326,669,640	$117,425,891
2040	$30,710,054	$8,513,212	-$899,342	-$226,185,201	$0	-$118,581,187	-$5,271,509	-$281,311,815	-$65,605,593	-$5,721,259	-$117,884,993	$115,253,122
2041	$30,771,254	$5,705,549	-$4,240,622	-$242,243,437	$0	$63,472,895	$6,531,290	$87,723,932	$18,871,549	$12,731,154	-$22,395,120	$108,513,104
2042	$76,056,358	$14,859,213	-$9,586,451	-$4,546,840	$0	$206,152,924	$11,364,659	$476,021,206	$101,369,962	$28,684,834	$172,006,626	$138,031,448
2043	$118,538,829	$34,166,098	-$1,927,765	-$24,328,964	$0	$254,867,700	-$602,602	$694,024,947	$207,454,037	$0	$445,700,026	$164,698,071
2044	$72,648,901	$14,751,839	-$8,496,845	-$26,986,169	$0	$118,803,379	$69,641	$320,365,599	$94,815,472	$0	$201,726,948	$180,354,922
2045	$77,642,120	$22,038,604	-$1,664,594	-$34,253,733	$0	$266,859,290	-$2,007,674	$739,032,527	$224,624,457	-$2,655,098	$490,355,023	$211,982,079
2046	$108,151,435	$28,650,754	-$4,739,845	-$36,504,598	$0	$143,183,241	-$8,087,274	$459,430,021	$158,251,075	-$15,932,611	$383,698,905	$240,786,108
2047	$171,555,757	$51,545,961	-$308,429	-$56,247,901	$0	$273,979,185	-$5,728,664	$791,658,578	$250,356,003	-$16,741,871	$566,531,232	$272,585,931
2048	$160,317,368	$36,669,536	-$13,884,055	-$77,495,495	$0	$196,103,513	-$647,295	$535,653,184	$160,610,233	$0	$346,095,307	$297,266,651
2049	$135,223,360	$38,411,395	-$2,865,474	-$55,776,679	$0	$63,241,103	-$750,502	$177,603,198	$54,710,728	$0	$120,931,947	$311,895,823
2050	$244,332,394	$84,579,476	$12,763,092	-$48,385,728	$0	-$438,652,213	-$576,265	-$1,180,007,417	-$348,365,157	$0	-$739,336,767	$276,618,011
2051	$229,840,993	$78,438,936	$10,677,097	-$47,654,512	$0	-$6,361,214	-$559,966	-$12,162,463	-$2,083,074	$0	-$1,231,925	$282,943,184

NERA
Economic Consulting

NERA Economic Consulting
99 High St, 16th Floor
Boston, Massachusetts 02110
Tel: +1 617 927 4500
Fax: +1 617 927 4501
www.nera.com