BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-160:
Clean Air Task Force Toll from Coal

Craig

Moffat, Colorado

Owner MidAmerican Energy Holdings Co, 12.9%, Salt River Project, 12%, Salt River Project, 19.3%, Tri-State G & T Assn Inc, 49.3%, Xcel Energy Inc, 6.5%

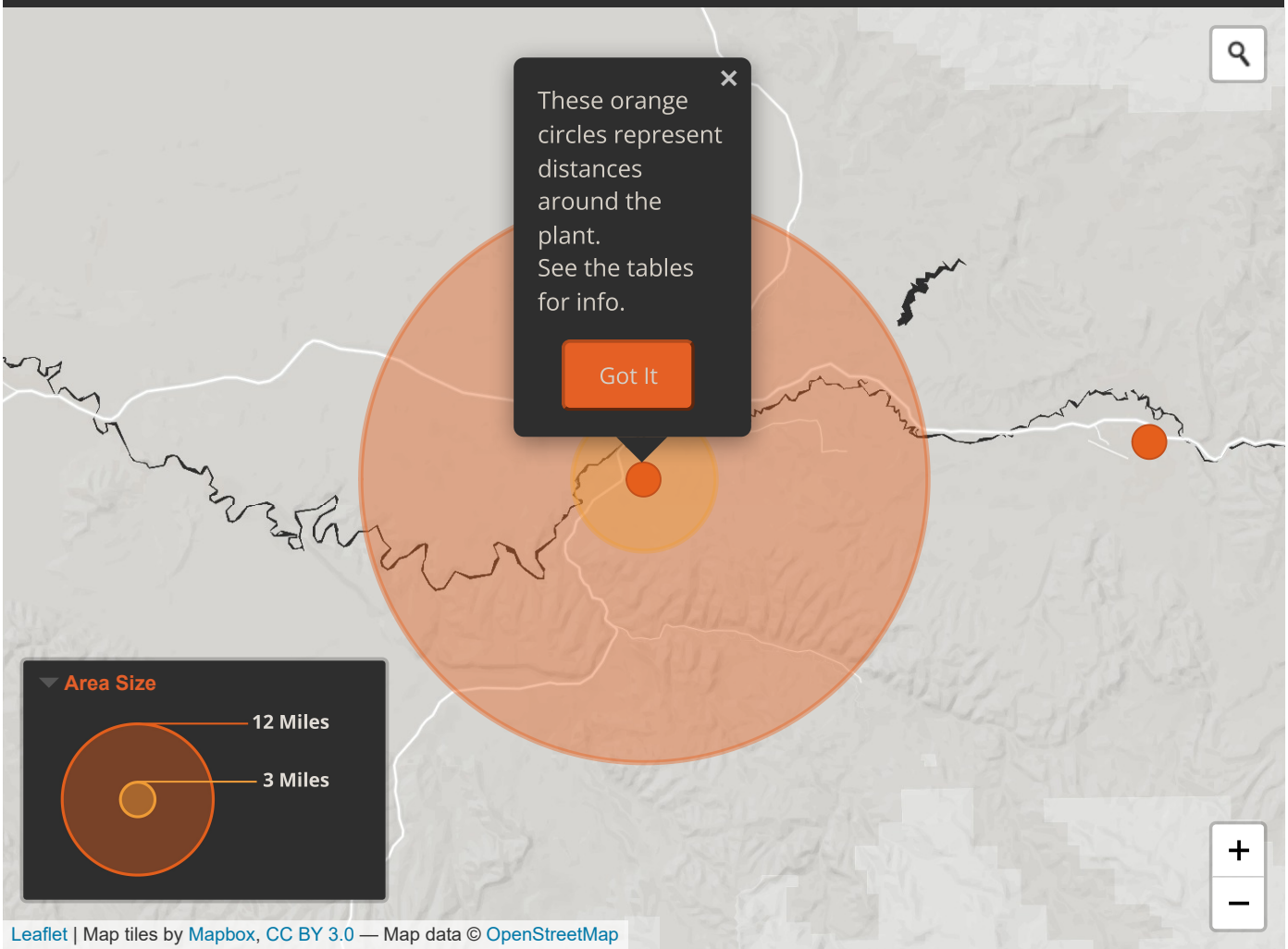
Size of Plant 1,304 MW

In Service Date 1979-1984

SO_2 Emissions 3,018 tons per year

NO_x Emissions 7,985 tons per year

CO_2 Emissions 9,181,677 tons per year



Health Impacts

(per year)

Deaths 21

Hospital Admissions 2

Asthma ER Visits 5

Heart Attacks 8

At Risk Population

	3 Miles	12 Miles
Population	410	12,135

Acute Bronchitis 14
Asthma Attacks 270
Work Loss Days 1,234

Number of Children	123	3,642
Number of Schools	--	13
Hospitals	--	1
Nursing Homes	0	1
Places of Worship	--	1
People of Color vs State Average	8% vs. 30%	18% vs. 30%
Poverty Rate vs State Average	4% vs. 13%	11% vs. 13%

CLEAN AIR TASK FORCE

Methodology

Powered by ZevRoss Spatial Analysis

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Motion to Intervene and Request for Rehearing and Stay of
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Exhibit 2-161
SPP West Press Release

March 20, 2025

SPP first RTO to operate in both interconnections with tariff approval

LITTLE ROCK, ARK. — Southwest Power Pool (SPP) will soon be the first regional transmission organization (RTO) in the U.S. to provide full services in both the Eastern and Western Interconnections of the nation's power grid. On March 20, the Federal Energy Regulatory Commission (FERC) unanimously approved Southwest Power Pool's amended tariff that includes provisions enabling Western members to join the RTO. The Commission's approval paves the way for seven Western entities, all of whom are participants in SPP's Western Energy Imbalance Service (WEIS) market today, to begin participating in SPP's Integrated Marketplace, transmission planning, reliability coordination and other RTO services beginning in April 2026.

On June 4, 2024, SPP filed its amended tariff with FERC to accommodate requirements for Western entities pursuing RTO membership or increased participation as part of the expansion of the SPP RTO: Basin Electric Power Cooperative; Colorado Springs Utilities; Deseret Power Electric Cooperative; the Municipal Energy Agency of Nebraska (MEAN); Platte River Power Authority; Tri-State Generation and Transmission Association; and the Western Area Power Administration Colorado River Storage Project, Rocky Mountain and Upper Great Plains regions.

"I am pleased to announce FERC's approval of the amended RTO tariff," said Barbara Sugg, SPP president and CEO. "Expanding the RTO into the Western Interconnection is an exciting step in SPP's growth, bringing value to new and existing members while enhancing reliability in both interconnections."

The expansion of the RTO is part of Aspire 2026, SPP's five-year strategic plan, which details opportunities to fully integrate Western facilities into SPP's existing market system in a way that creates meaningful, equitable value for new and existing members.

"The Western expansion of the SPP RTO bolsters reliability and resiliency for our members as we grow and diversify our resource portfolio while reducing emissions," said Tri-State Generation and Transmission Association CEO Duane Highley. "We greatly value the full benefits of the SPP RTO, including day-ahead and ancillary services markets, efficient regional transmission planning, a common transmission tariff and participatory governance model that help us to further reduce costs for our members across the West. Prior to SPP RTO West entry, we will be making a filing with our state regulators highlighting these market benefits."

"SPP's RTO expansion into the Western Interconnect will help us to reduce our overall carbon footprint for MEAN's power resources through the economic dispatch of a wholesale power market and maximizing operational efficiencies of renewable resources," said MEAN Director of Wholesale Operations Brad Hans. "As a

member of SPP's RTO in the Eastern Interconnect for several years, MEAN recognizes the benefits of participating in that market and the energy cost savings it provides as well as SPP's member-driven business model."

"In 2018, when we outlined our plan to pursue a noncarbon energy portfolio, it was very clear to us that an integral component to this plan was to join a power market," shares Jason Frisbie, CEO and general manager of Platte River Power Authority. "Over the last seven years our teams across the organization have been dedicated to this effort working closely with SPP to be ready for the moment we join the RTO, which will help us integrate more renewable energy onto our system and manage our energy costs."

"With the complexities of today's energy industry and the regulations that define it, an adaptable electric grid with access to both local and regional resources is essential for managing customer costs and maintaining service reliability," said Colorado Springs Utilities Chief Executive Officer Travas Deal. "We strongly believe the SPP RTO will help us achieve this goal, while also connecting us with vital transmission resources as we pursue new and cleaner forms of electric generation. So, FERC's approval of the amended tariff is very encouraging for us and our customers as we implement our Sustainable Energy Plan."

SPP is working with additional Western utilities who have expressed interest in joining the RTO once this initial expansion is complete.

Separately, SPP is developing Markets+, another market designed to bring significant incremental value to the Western Interconnection. SPP received FERC's approval of the Markets+ tariff in January, and is working with interested parties to finalize plans to fund the market's development and launch. With the addition of Markets+, SPP will have a solid presence in the West, operating two markets and serving as the program administrator for the Western Power Pool's Western Resource Adequacy Program (WRAP).

"Multiple markets maximize value for all participants," said Sugg. "SPP has operated a Western market since 2021, and with the expansion of the RTO's Integrated Marketplace in 2026 and launch of Markets+ in 2027, we're looking forward to bringing additional affordability, reliability, equity and sustainability to the West."

SPP first earned FERC's approval as an RTO in October 2004, and over the last two decades has expanded its RTO footprint in the Eastern Interconnection from eight to 14 states. This expansion would grow SPP's RTO service territory to encompass all or part of 17 states. SPP has been engaged with parties interested in evaluating the benefits and requirements of RTO membership in the Western Interconnection since Oct. 20, 2020. The SPP board of directors approved the initial RTO expansion terms and conditions in July 2021, the DC tie terms and conditions in July 2022 and the WAPA Colorado River Storage Project terms and conditions in January 2023. The expansion of the SPP RTO is scheduled to go live April 1, 2026.

Meghan Sever, 501-482-2393, msever@spp.org

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Exhibit to
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Public Interest Organizations

Exhibit 2-162
EIA Generating Unit Annual Capital and Life Extension Costs Analysis

Independent Statistics & Analysis
U.S. Energy Information Administration

Generating Unit Annual Capital and Life Extension Costs Analysis

December 2019

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Generating Unit Annual Capital and Life Extension Costs Analysis

In a period of accelerating retirements of electric power generators, EIA sought to revisit its assumptions of age-related generation costs. EIA commissioned Sargent & Lundy (S&L) to evaluate capital expenditures (CAPEX) and operations and maintenance (O&M) costs for non-nuclear generating units, with a particular emphasis on how costs of coal and other fossil-fueled plants change over time. The following report represents S&L's findings. A separate EIA report, *Updates to Cost Assumptions in the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)*,[1] details subsequent updates to the EMM module.

The following report was accepted by EIA in fulfillment of contract number DE-EI0003250. All views expressed in this report are solely those of the contractor and acceptance of the report in fulfillment of contractual obligations does not imply agreement with nor endorsement of the findings contained herein. Responsibility for accuracy of the information contained in this report lies with the contractor. Although intended to be used to inform the updating of EIA's EMM module of NEMS, EIA is not obligated to modify any of its models or data in accordance with the findings of this report.

[1] https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/addendum.pdf

Prepared by

Sargent & Lundy Consulting

55 East Monroe Street
Chicago, Illinois 60603-5780

FINAL

Generating Unit Annual Capital and Life Extension Costs Analysis

Final Report on Modeling Aging-Related Capital and O&M Costs

Prepared for

eia

U.S. Energy Information Administration

SL-014201
May 2018

Project 13651-001

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Sargent & Lundy is a full-service architect-engineering firm that has been dedicated exclusively to the electric power industry for over 125 years. Sargent & Lundy has provided comprehensive planning, development, permitting, technical and financial consulting, engineering, design, construction management, and commissioning services for electric power generation and power delivery projects—1,557 clients in 88 countries worldwide—since its founding in 1891. Having designed 958 power plants, totaling 140,667 MW of electric generation capacity, Sargent & Lundy is regarded as one of the oldest, largest, and most experienced power generation engineering companies in the U.S.

Sargent & Lundy's roles on electric power generation projects include full-design architect-engineer, owner's engineer, lender's independent engineer/technical advisor, and consultant. Our services include specialized technical advisory and consulting services to complete engineering and program management, encompassing procurement, construction management, technology transfer, and assistance with construction. Sargent & Lundy provides professional consulting, engineering, and design services throughout the lifecycle of power generation projects, from project concept and development, through detailed design and procurement, to construction and operation.

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CONTENTS

Section Page

EXECUTIVE SUMMARY 1

Identifying Impacts of Aging on Generation Cost and Operation 1

Modeling Impacts of Aging in EIA Projections 3

Existing Treatment of Aging in EIA's Electricity Market Module 3

Need for Update to EIA's Treatment of Aging 3

Analysis of Aging Impacts in Publicly-Reported Cost Information 4

Cost Breakdowns in Reported Data 4

Data Compilation 5

Identifying Changes in Spending Patterns over Plant Life 6

Differences in Spending Approach by Plant Type 6

Potential Benefits of CAPEX and O&M Spending on Future Spending 6

Potential Impacts of Plant Age on Future Spending 7

Effect of Plant Capacity (MW) 7

Effect of Plant Capacity Factor 8

Effect of External Market Conditions 9

Effect of Regulatory Environment 10

Effect of Fuel Characteristics 10

Effect of Flue Gas Desulfurization 10

Proposed Updates to EMM Methodology 11

Coal Steam 11

Gas/Oil Steam 13

Gas/Oil Combined Cycle and Gas/Oil Combustion Turbine 15

Conventional Hydroelectric 16

Pumped Storage 17

Solar Photovoltaic 17

Solar Thermal 18

Geothermal 18

Wind 19

Recommended Areas for Further Study 20

CONTENTS

Section Page

1. INTRODUCTION 1-1

2. ASSESSMENT METHODOLOGY 2-1

2.1 Background 2-1

2.2 Sources of Cost Information 2-2

2.2.1 FERC Form 1 Data 2-2

2.2.2 Sargent & Lundy Internal Data 2-5

2.2.3 Other Data Sources 2-6

2.3 Data Validation 2-6

2.4 Data Normalization 2-9

2.5 Statistical Tests 2-11

2.5.1 Consistency of FERC Form 1 and Sargent & Lundy Internal Data 2-11

2.5.2 Significance of Plant Age on Annual Capital and O&M Expenditures 2-13

2.5.3 Autocorrelation of Time Series Data 2-14

3. COAL STEAM 3-1

3.1 Data Description 3-1

3.2 Summary of Results 3-2

3.2.1 Recommended CAPEX Values 3-2

3.2.2 Recommended O&M Values 3-4

3.2.3 Effect of Plant Capacity Factor 3-5

3.2.4 Effect of External Market Conditions 3-6

3.2.5 Effect of Regulatory Environment 3-7

3.2.6 Effect of Fuel Characteristics 3-8

4. GAS/OIL STEAM 4-1

4.1 Data Description 4-1

4.2 Summary of Results 4-1

4.2.1 Recommended CAPEX Values 4-1

CONTENTS

Section Page

4.2.2 Recommended O&M Values 4-3
4.2.3 Effect of Plant Capacity Factor 4-4
4.2.4 Effect of External Market Conditions 4-4

5. GAS/OIL COMBINED CYCLE 5-1

5.1 Data Description 5-1

5.2 Summary of Results 5-2

6. GAS/OIL COMBUSTION TURBINE 6-1

6.1 Data Description 6-1

6.2 Summary of Results 6-2

7. CONVENTIONAL HYDROELECTRIC 7-1

7.1 Data Description 7-1

7.2 Summary of Results 7-2

8. PUMPED HYDROELECTRIC STORAGE 8-1

8.1 Data Description 8-1

8.2 Summary of Results 8-1

9. SOLAR PHOTOVOLTAIC 9-1

9.1 Data Description 9-1

9.2 Summary of Results 9-1

10. SOLAR THERMAL 10-1

10.1 Data Description 10-1

10.2 Summary of Results 10-1

CONTENTS

Section Page

11. GEOTHERMAL 11-1

11.1 Data Description 11-1

11.2 Summary of Results 11-1

12. WIND 12-1

12.1 Data Description 12-1

12.2 Summary of Results 12-2

APPENDIX A. REGRESSION ANALYSIS – COAL STEAM A-1

Capital Expenditures – All Plant Sizes A-2

Operations & Maintenance Expenditures – All Plant Sizes A-3

Capital Expenditures – Less than 500 MW A-4

Operations & Maintenance Expenditures – Less than 500 MW A-5

Capital Expenditures – Between 500 MW and 1,000 MW A-7

Operations & Maintenance Expenditures – Between 500 MW and 1,000 MW A-8

Capital Expenditures – Between 1,000 MW and 2,000 MW A-9

Operations & Maintenance Expenditures – Between 1,000 MW and 2,000 MW A-10

Capital Expenditures – Greater than 2,000 MW A-12

Operations & Maintenance Expenditures – Greater than 2,000 MW A-13

Capital Expenditures – Capacity Factor Less than 50% A-14

Operations & Maintenance Expenditures – Capacity Factor less than 50% A-15

Capital Expenditures – Capacity Factor Greater than 50% A-17

Operations & Maintenance Expenditures – Capacity Factor Greater than 50% A-18

Capital Expenditures – Regulated vs. Deregulated A-19

Operations & Maintenance Expenditures – Regulated vs. Deregulated A-20

CONTENTS

Section Page

Capital Expenditures – FGD vs. No FGD A-20

Operations & Maintenance Expenditures – FGD vs. No FGD A-21

Capital Expenditures – Bituminous vs. Subbituminous A-22

Operations & Maintenance Expenditures – Bituminous vs. Subbituminous A-23

Effect of Plant Capacity Factor A-24

APPENDIX B. REGRESSION ANALYSIS – GAS/OIL STEAM B-1

Capital Expenditures – All Plant Sizes B-2

Operations & Maintenance Expenditures – All Plant Sizes B-2

Capital Expenditures – Less than 500 MW B-4

Operations & Maintenance Expenditures – Less than 500 MW B-4

Capital Expenditures – Between 500 MW and 1,000 MW B-6

Operations & Maintenance Expenditures – Between 500 MW and 1,000 MW B-7

Capital Expenditures – Greater than 1,000 MW B-8

Operations & Maintenance Expenditures – Greater than 1,000 MW B-9

APPENDIX C. REGRESSION ANALYSIS – GAS/OIL COMBINED CYCLE C-1

Capital Expenditures – All Plant Sizes C-2

Operations & Maintenance Expenditures – All Plant Sizes C-2

Capital Expenditures – Less than 500 MW C-4

Operations & Maintenance Expenditures – Less than 500 MW C-5

Capital Expenditures – Between 500 MW and 1,000 MW C-6

Operations & Maintenance Expenditures – Between 500 MW and 1,000 MW C-7

Capital Expenditures – Greater than 1,000 MW C-9

Operations & Maintenance Expenditures – Greater than 1,000 MW C-9

CONTENTS

Section Page

Capital Expenditures – Capacity Factor Less than 50% C-11

Operations & Maintenance Expenditures – Capacity Factor Less than 50% C-12

Capital Expenditures – Capacity Factor Greater than 50% C-13

Operations & Maintenance Expenditures – Capacity Factor Greater than 50% C-14

APPENDIX D. REGRESSION ANALYSIS – GAS/OIL COMBUSTION TURBINE D-1

Capital Expenditures – All Plant Sizes D-2

Operations & Maintenance Expenditures – All Plant Sizes D-2

Capital Expenditures – Less than 100 MW D-4

Operations & Maintenance Expenditures – Less than 100 MW D-5

Capital Expenditures – Between 100 MW and 300 MW D-6

Operations & Maintenance Expenditures – Between 100 MW and 300 MW D-7

Capital Expenditures – Greater than 300 MW D-9

Operations & Maintenance Expenditures – Greater than 300 MW D-10

APPENDIX E. REGRESSION ANALYSIS – CONVENTIONAL HYDROELECTRIC E-1

Capital Expenditures – All Plant Sizes E-2

Operations & Maintenance Expenditures – All Plant Sizes E-3

APPENDIX F. REGRESSION ANALYSIS – PUMPED HYDROELECTRIC STORAGE F-1

Capital Expenditures – All Plant Sizes F-2

Operations & Maintenance Expenditures – All Plant Sizes F-3

APPENDIX G. REGRESSION ANALYSIS – SOLAR PHOTOVOLTAIC G-1

Capital Expenditures G-2

Operations & Maintenance Expenditures G-4

CONTENTS

Section Page

APPENDIX H. REGRESSION ANALYSIS – SOLAR THERMAL H-1

APPENDIX I. REGRESSION ANALYSIS – GEOTHERMAL I-1

Capital Expenditures I-2

Operations & Maintenance Expenditures I-3

APPENDIX J. REGRESSION ANALYSIS – WIND J-1

Capital Expenditures J-2

Operations & Maintenance Expenditures J-8

TABLES AND FIGURES

Table or Figure — Page

Table ES-1 — Variables Affecting Annual Changes in Real Spending per kW 2
Table ES-2 — High Capacity Factor Coal Plants – Spending Comparison 10
Table ES-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors 11
Table ES-4 — Coal Steam O&M Comparison with Existing EMM 12
Table ES-5 — Gas/Oil Steam CAPEX Results 13
Table ES-6 — Gas/Oil Steam O&M Comparison with Existing EMM 14
Table ES-7 — Gas/Oil CC and CT CAPEX and O&M Comparison with Existing EMM 16
Table ES-8 — Hydroelectric CAPEX and O&M Comparison with Existing EMM 17
Table ES-9 — Pumped Storage CAPEX and O&M Comparison with Existing EMM 17
Table ES-10 — Geothermal CAPEX and O&M Comparison with Existing EMM 19
Table ES-11 — Wind CAPEX and O&M Comparison with Existing EMM 19
Table 2-1 — Summary of Valid Data Points 2-8
Table 3-1 — Coal Steam Cost Data Distribution 3-1
Table 3-2 — Effect of Data Validation Filters on Coal Data Points 3-2
Table 3-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors 3-3
Table 3-4 — Coal Plant Indicative Typical CAPEX Projects and Intervals 3-4
Table 3-5 — Coal Steam O&M Comparison with Existing EMM 3-5
Table 3-6 — High Capacity Factor Coal Plants – Spending Comparison 3-7
Table 4-1 — Gas/Oil Steam Cost Data Distribution 4-1
Table 4-2 — Gas/Oil Steam CAPEX Results 4-2
Table 4-3 — Gas/Oil Steam O&M Comparison with Existing EMM 4-3
Table 5-1 — Gas/Oil CC Cost Data Distribution 5-1
Table 5-2 — Gas/Oil CC CAPEX and O&M Comparison with Existing EMM 5-3
Table 6-1 — Gas/Oil Combustion Turbine Cost Data Distribution 6-1
Table 6-2 — Gas/Oil Combustion Turbine CAPEX and O&M Comparison with Existing EMM 6-3
Table 7-1 — Conventional Hydroelectric Cost Data Distribution 7-1
Table 7-2 — Hydroelectric CAPEX and O&M Comparison with Existing EMM 7-2
Table 8-1 — Pumped Storage Cost Data Distribution 8-1
Table 8-2 — Pumped Storage CAPEX and O&M Comparison with Existing EMM 8-2
Table 9-1 — Solar Photovoltaic Cost Data Distribution 9-1
Table 11-1 — Geothermal Cost Data Distribution 11-1
Table 11-2 — Geothermal CAPEX and O&M Comparison with Existing EMM 11-1

TABLES AND FIGURES

Table or Figure — Page

Table 12-1 — Wind Cost Data Distribution 12-1
Table 12-2 — Wind CAPEX and O&M Comparison with Existing EMM 12-2
Table A-1 — Regression Statistics – Coal CAPEX for All MW A-2
Table A-2 — Regression Statistics – Coal O&M for All MW A-3
Table A-3 — Regression Statistics – Coal CAPEX < 500 MW A-4
Table A-4 — Regression Statistics – Coal O&M < 500 MW A-5
Table A-5 — Regression Statistics – Coal CAPEX 500 MW to 1,000 MW A-7
Table A-6 — Regression Statistics – Coal O&M 500 MW to 1,000 MW A-8
Table A-7 — Regression Statistics – Coal CAPEX 1,000 MW to 2,000 MW A-9
Table A-8 — Regression Statistics – Coal O&M 1,000 MW to 2,000 MW A-10
Table A-9 — Regression Statistics – Coal CAPEX > 2,000 MW A-12
Table A-10 — Regression Statistics – Coal O&M > 2,000 MW A-13
Table A-11 — Regression Statistics – Coal CAPEX for Capacity Factor < 50% A-14
Table A-12 — Regression Statistics – Coal O&M for Capacity Factor < 50% A-15
Table A-13 — Regression Statistics – Coal CAPEX for Capacity Factor > 50% A-17
Table A-14 — Regression Statistics – Coal O&M for Capacity Factor > 50% A-18
Table A-15 — Regression Statistics – Coal CAPEX for Regulated/Deregulated A-19
Table A-16 — Regression Statistics – Coal CAPEX for FGD/No FGD A-21
Table A-17 — Regression Statistics – Coal CAPEX for Bituminous/Subbituminous A-22
Table B-1 — Regression Statistics – Gas/Oil Steam CAPEX for All MW B-2
Table B-2 — Regression Statistics – Gas/Oil Steam O&M for All MW B-3
Table B-3 — Regression Statistics – Gas/Oil Steam CAPEX < 500 MW B-4
Table B-4 — Regression Statistics – Gas/Oil Steam O&M < 500 MW B-5
Table B-5 — Regression Statistics – Gas/Oil Steam CAPEX 500 MW to 1,000 MW B-6
Table B-6 — Regression Statistics – Gas/Oil Steam O&M 500 MW to 1,000 MW B-7
Table B-7 — Regression Statistics – Gas/Oil Steam CAPEX > 1,000 MW B-8
Table B-8 — Regression Statistics – Gas/Oil Steam O&M > 1,000 MW B-9
Table C-1 — Regression Statistics – CC CAPEX for All MW C-2
Table C-2 — Regression Statistics – CC O&M for All MW C-3
Table C-3 — Regression Statistics – CC CAPEX < 500 MW C-4
Table C-4 — Regression Statistics – CC O&M < 500 MW C-5
Table C-5 — Regression Statistics – CC CAPEX 500 MW to 1,000 MW C-6

TABLES AND FIGURES

Table or Figure — Page

Table C-6 — Regression Statistics – CC O&M 500 MW to 1,000 MW C-7
Table C-7 — Regression Statistics – CC CAPEX > 1,000 MW C-9
Table C-8 — Regression Statistics – CC O&M > 1,000 MW C-10
Table C-9 — Regression Statistics – CC CAPEX for Capacity Factor < 50% C-11
Table C-10 — Regression Statistics – CC O&M for Capacity Factor < 50% C-12
Table C-11 — Regression Statistics – CC CAPEX for Capacity Factor > 50% C-13
Table C-12 — Regression Statistics – CC O&M for Capacity Factor > 50% C-14
Table D-1 — Regression Statistics – CT CAPEX for All MW D-2
Table D-2 — Regression Statistics – CT O&M for All MW D-3
Table D-3 — Regression Statistics – CT CAPEX < 100 MW D-4
Table D-4 — Regression Statistics – CT O&M < 100 MW D-5
Table D-5 — Regression Statistics – CT CAPEX 100 MW to 300 MW D-6
Table D-6 — Regression Statistics – CT O&M 100 MW to 300 MW D-7
Table D-7 — Regression Statistics – CT CAPEX > 300 MW D-9
Table D-8 — Regression Statistics – CT O&M > 300 MW D-10
Table E-1 — Regression Statistics – Hydroelectric CAPEX for All MW E-2
Table E-2 — Regression Statistics – Hydroelectric O&M for All MW E-3
Table F-1 — Regression Statistics – Pumped Hydroelectric CAPEX for All MW F-2
Table F-2 — Regression Statistics – Pumped Hydroelectric O&M for All MW F-3
Table G-1 — Regression Statistics – Solar PV CAPEX for All MW G-3
Table G-2 — Example of Calculation Method Differences G-4
Table G-3 — Summary of Industry O&M Cost Data for Solar PV G-8
Table I-1 — Regression Statistics – Geothermal CAPEX for All MW I-2
Table I-2 — Regression Statistics – Geothermal O&M for All MW I-3
Table I-3 — Geothermal All MW Summary of Results I-4
Table J-1 — Regression Statistics – Wind CAPEX for All MW J-2
Table J-2 — Wind All MW Summary of Results J-3
Table J-3 — Regression Statistics – Wind CAPEX for 0-100 MW J-3
Table J-4 — Wind < 100-MW Summary of Results J-4
Table J-5 — Regression Statistics – Wind CAPEX for 100-200 MW J-5
Table J-6 — Wind 100-200-MW Summary of Results J-6
Table J-7 — Regression Statistics – Wind CAPEX for Greater than 200 MW J-6

TABLES AND FIGURES

Table or Figure — Page

Table J-8 — Wind Greater than 200-MW Summary of Results J-7
Table J-9 — Regression Statistics – Wind O&M for All MW J-8
Table J-10 — Regression Statistics – Wind O&M for 0-100 MW J-9
Table J-11 — Regression Statistics – Wind O&M for 100-200 MW J-10
Table J-12 — Regression Statistics – Wind O&M Greater than 200 MW J-11

Figure ES-1 — Capacity Factor vs. Age for All Coal Plants 8
Figure ES-2 — Capacity Factor vs. Age for All Gas/Oil Steam Plants 8
Figure 2-1 — CAPEX vs. Age for 500-MW Coal Plants – FERC and Sargent & Lundy Data 2-12
Figure 2-2 — U.S. Power Plant Fleet Capacity by Age and Fuel Type 2-13
Figure 3-1 — Capacity Factor vs. Age for All Coal Plants 3-6
Figure 4-1 — Capacity Factor vs. Age for All Gas/Oil Steam Plants 4-4
Figure A-1 — Coal Steam Dataset – CAPEX for All MW Plant Sizes A-2
Figure A-2 — Coal Steam Dataset – O&M for All MW Plant Sizes A-3
Figure A-3 — Coal Steam Dataset – CAPEX for Less than 500-MW Plant Size A-5
Figure A-4 — Coal Steam Dataset – O&M for Less than 500-MW Plant Size A-6
Figure A-5 — Coal Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size A-7
Figure A-6 — Coal Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size A-8
Figure A-7 — Coal Steam Dataset – CAPEX for 1,000-MW to 2,000-MW Plant Size A-10
Figure A-8 — Coal Steam Dataset – O&M for 1,000-MW to 2,000-MW Plant Size A-11
Figure A-9 — Coal Steam Dataset – CAPEX for Greater than 2,000-MW Plant Size A-12
Figure A-10 — Coal Steam Dataset – O&M for Greater than 2,000-MW Plant Size A-13
Figure A-11 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor < 50% A-15
Figure A-12 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor < 50% A-16
Figure A-13 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor > 50% A-17
Figure A-14 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor > 50% A-18
Figure A-15 — Coal Steam Dataset – CAPEX for Regulated/Deregulated A-19
Figure A-16 — Coal Steam Dataset – O&M for Regulated vs. Deregulated A-20
Figure A-17 — Coal Steam Dataset – CAPEX for FGD/No FGD A-21
Figure A-18 — Coal Steam Dataset – O&M for FGD vs. No FGD A-22
Figure A-19 — Coal Steam Dataset – CAPEX for Bituminous/Subbituminous A-23
Figure A-20 — Coal Steam Dataset – O&M for Bituminous vs. Subbituminous A-24

TABLES AND FIGURES

Table or Figure — Page

Figure A-21 — CAPEX vs. Age for All MW Coal Plants (2017 $/MWh) A-24
Figure A-22 — O&M vs. Age for All Coal Plants (2017 $/MWh) A-25
Figure A-23 — Capacity Factor vs. Age for All Coal Plants A-25
Figure A-24 — Capacity Factor vs. Age for All Gas/Oil Steam Plants A-26
Figure B-1 — Gas/Oil Steam Dataset – CAPEX for All Plant MW Sizes B-2
Figure B-2 — Gas/Oil Steam Dataset – O&M for All Plant MW Sizes B-3
Figure B-3 — Gas/Oil Steam Dataset – CAPEX for Less than 500-MW Plant Size B-4
Figure B-4 — Gas/Oil Steam Dataset – O&M for Less than 500-MW Plant Size B-5
Figure B-5 — Gas/Oil Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size B-6
Figure B-6 — Gas/Oil Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size B-7
Figure B-7 — Gas/Oil Steam Dataset – CAPEX for Greater than 1,000-MW Plant Size B-9
Figure B-8 — Gas/Oil Steam Dataset – O&M for Greater than 1,000-MW Plant Size B-10
Figure C-1 — Gas/Oil CC Dataset – CAPEX for All Plant MW Sizes C-2
Figure C-2 — Gas/Oil CC Dataset – O&M for All Plant MW Sizes C-3
Figure C-3 — Gas/Oil CC Dataset – CAPEX for Less than 500-MW Plant Size C-4
Figure C-4 — Gas/Oil CC Dataset – O&M for Less than 500-MW Plant Size C-5
Figure C-5 — Gas/Oil CC Dataset – CAPEX for 500-MW to 1,000-MW Plant Size C-7
Figure C-6 — Gas/Oil CC Dataset – O&M for 500-MW to 1,000-MW Plant Size C-8
Figure C-7 — Gas/Oil CC Dataset – CAPEX for Greater than 1,000-MW Plant Size C-9
Figure C-8 — Gas/Oil CC Dataset – O&M for Greater than 1,000 MW Plant Size C-10
Figure C-9 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor < 50% C-11
Figure C-10 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor < 50% C-12
Figure C-11 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor > 50% C-14
Figure C-12 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor > 50% C-15
Figure D-1 — Gas/Oil CT Dataset – CAPEX for All Plant MW Sizes D-2
Figure D-2 — Gas/Oil CT Dataset – O&M for All Plant MW Sizes D-3
Figure D-3 — Gas/Oil CT Dataset – CAPEX for Less than 100-MW Plant Size D-4
Figure D-4 — Gas/Oil CT Dataset – O&M for Less than 100-MW Plant Size D-5
Figure D-5 — Gas/Oil CT Dataset – CAPEX for Between 100-MW and 300-MW Plant Size D-7
Figure D-6 — Gas/Oil CT Dataset – O&M for Between 100-MW and 300-MW Plant Size D-8
Figure D-7 — Gas/Oil CT Dataset – CAPEX for Greater than 300-MW Plant Size D-9
Figure D-8 — Gas/Oil CT Dataset – O&M for Greater than 300-MW Plant Size D-10

TABLES AND FIGURES

Table or Figure — Page

Figure E-1 — Conventional Hydroelectric Dataset – CAPEX for All MW Plant Sizes E-2
Figure E-2 — Conventional Hydroelectric – O&M for All MW Plant Sizes E-3
Figure F-1 — Pumped Hydroelectric Dataset – CAPEX for All MW Plant Sizes F-2
Figure F-2 — Pumped Hydroelectric – O&M for All Plant MW Sizes F-3
Figure G-1 — Solar PV Dataset – CAPEX for All MW Plant Sizes G-3
Figure G-2 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (< 5 MW) G-5
Figure G-3 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (> 5 MW) G-6
Figure G-4 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (< 5 MW) G-6
Figure G-5 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (> 5 MW) G-7
Figure G-6 — Annual Site O&M Cost per MWh vs. Age of Project G-7
Figure G-7 — Annual Site O&M Cost per kW-Year Capacity vs. Age of Project G-8
Figure I-1 — Geothermal Dataset – CAPEX for All MW Plant Sizes I-2
Figure I-2 — Geothermal Dataset – O&M for All MW Plant Sizes I-3
Figure J-1 — Wind Dataset – CAPEX for All MW Plant Sizes J-2
Figure J-2 — Wind Dataset – CAPEX for 0-100-MW Plant Sizes J-4
Figure J-3 — Wind Dataset – CAPEX for 100-200-MW Plant Sizes J-5
Figure J-4 — Wind Dataset – CAPEX for Greater than 200-MW Plant Sizes J-7
Figure J-5 — Wind Dataset – O&M for All MW Plant Sizes J-8
Figure J-6 — Wind Dataset – O&M for 0-100-MW Plant Sizes J-9
Figure J-7 — Wind Dataset – O&M for 100-200-MW Plant Sizes J-10
Figure J-8 — Wind Dataset – O&M for Plant Sizes Greater than 200 MW J-11

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
2017$	2017 dollars
A&G	Administrative and general
AEO	*Annual Energy Outlook*
ARIMA	Autoregressive integrated moving average
ATB	Annual Technology Baseline
CAPEX	Capital expenditures
CC	Combined cycle
CF	Capacity factor
COD	Commercial operation date
CT	Combustion turbine
DOE	Department of Energy
EIA	Energy Information Administration
EMM	Electricity Market Module
ESP	Electrostatic precipitator
FERC	Federal Energy Regulatory Commission
FERC Form 1	FERC Form No. 1
FGD	Flue gas desulfurization
Hg	Mercury
HP	High pressure
ID	Identifier or induced draft
IP	Intermediate pressure
IPP	Independent power producer
IRENA	International Renewable Energy Agency

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
kW	Kilowatts
kW-yr	Kilowatt-years
LCOE	Levelized cost of electricity
LP	Low pressure
MMRA	Major maintenance reserve account
MW	Megawatts
MWh	Megawatt-hours
NO_X	Nitrogen oxide
NREL	National Renewable Energy Laboratory
OEA	Office of Energy Analysis
O&M	Operations and maintenance
PM	Particulate matter
PV	Photovoltaic
R^2	R-squared
Sargent & Lundy	Sargent & Lundy LLC
SO_2	Sulfur dioxide
TCP	Total Cost of Plant

EXECUTIVE SUMMARY

IDENTIFYING IMPACTS OF AGING ON GENERATION COST AND OPERATION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

For most types of generators evaluated, we did not find a statistically significant relationship between plant age and costs (both CAPEX and O&M). CAPEX spending over the life of each plant represents a series of capital projects—rather than a single life extension project—that includes both discretionary spending and

vendor-specified spending. For discretionary spending, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Vendor-specified spending is primarily for major maintenance, typically based on cumulative hours of operation and/or cumulative starts, and more commonly applied to gas/oil CC and CT plants. We did, however, find a statistically significant relationship between age and CAPEX spending for fossil steam coal generators with flue gas desulfurization (FGD) equipment, and between age and O&M spending for conventional hydroelectric plants and wind turbines. We also found age and CAPEX spending to be significantly correlated for CC and CT plants, although measured in terms of operating hours or starts, rather than years. Table ES-1 summarizes the variables found to have a significant effect on annual changes in real spending per kilowatt (kW) for each generator type. We recommend the EIA incorporate these variables in the EMM representation of CAPEX and O&M.

Table ES-1 — Variables Affecting Annual Changes in Real Spending per kW

Generating Capacity	CAPEX Spending	O&M Spending
Coal Steam Plants	Age and FGD (see Table ES-3)	-
Gas/Oil Steam Plants	Capacity (see Table ES-5)	-
Gas/Oil Combined-Cycle Plants	Operating Hours (see Table ES-7)	-
Gas/Oil Combustion Turbines	Starts (see Table ES-7)	-
Conventional Hydropower	-	Age (Regression Equation)
Pumped Storage – Hydraulic Turbine Reversible	-	-
Solar Thermal – Central Tower	-	-
Solar Photovoltaic – Single-Axis Tracking	-	-
Geothermal	-	-
Wind	Capacity (see Table ES-11)	Age (Regression Equation)

While we did not find a consistent relationship between aging and CAPEX and O&M costs, changes in performance-related factors and external market conditions are also related to changes in these costs over time. Examples of these factors and conditions include the following:

- Plant efficiency (heat rate)
- Capacity degradation
- Outage rates
- Market prices (electricity, fuel)

These factors and conditions were not part of the scope of our study. We recommend the EIA consider studying these in the future.

MODELING IMPACTS OF AGING IN EIA PROJECTIONS

Existing Treatment of Aging in EIA's Electricity Market Module

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX that is intended to extend the life or preserve the performance of an existing generator. In the EMM, costs for plant O&M do not vary with plant age.

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is $0.18 per kilowatt-year (/kW-year) for existing CC plants, $9/kW-year for existing gas/oil steam plants, and $18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to $7.25/kW-year, $16/kW-year, and $25/kW-year, respectively, after a plant reaches 30 years of age.[1] The average annual CAPEX in the EMM for existing CT plants is $1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

Need for Update to EIA's Treatment of Aging

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 ("FERC Form 1").[2] The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy's update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

[1] Internal communication with EIA, February 2018.
[2] FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.
2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed ($/kW-year) or variable ($/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in Section 2.

ANALYSIS OF AGING IMPACTS IN PUBLICLY-REPORTED COST INFORMATION

Cost Breakdowns in Reported Data

Our analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

The reporting formats of our in-house data and the FERC Form 1 data have a clear delineation between CAPEX and O&M. However, while the in-house data often contains an explicit breakdown between fixed and variable O&M, the FERC Form 1 accounts for O&M are not categorized as such. Rather, the reported O&M costs in a given account are the combined fixed and variable costs at the reported generating output. Thus, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data.

O&M costs for the following technologies are essentially all fixed: solar thermal (central tower), solar PV (single-axis tracking), geothermal, and wind. By definition, fixed O&M costs are independent of plant generation, so they are expressed in $/kW-year.

O&M costs for the following technologies include a significant variable component: coal steam, gas/oil steam, gas/oil CC, gas/oil CTs, conventional hydropower, and pumped storage (hydraulic turbine reversible). By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh.

As mentioned, the variable O&M components cannot be clearly delineated from the total reported O&M costs. For this assessment, the variable components were combined with the fixed components and expressed in $/kW-year. The combined total O&M was found to correspond to the combined total O&M representation in the EMM, which includes a $/MWh variable O&M breakout, as presented in the subsections below.

CAPEX spending values, expressed in $/kW-year, were derived from the new dataset as an additive to the EMM O&M costs and as replacements for the existing EMM CAPEX representation for all technologies, except for gas/oil CC and gas/oil CTs. CAPEX spending for gas/oil CC and gas/oil CTs was found to be primarily for major maintenance events, which are already represented as a $/MWh variable O&M cost in the EMM.

Data Compilation

The data compilation for this analysis consisted of the following annual plant data (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant megawatts (MW) (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

All available and validated cost data over the plant operating life, historical or forecasted, was normalized as follows for each plant:

- Annual O&M in 2017 $/kW-year versus age (years from commercial operation date [COD])
- Annual CAPEX in 2017 $/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

In all cases, the yearly values are expressed in constant 2017 price levels and would increase annually with the inflation rate.

IDENTIFYING CHANGES IN SPENDING PATTERNS OVER PLANT LIFE

Differences in Spending Approach by Plant Type

CAPEX spending over the life of each plant represents a series of capital projects throughout the plant life, rather than a single life extension project. This consists of both discretionary spending and vendor-specified spending, examples of which are as follows:

- Discretionary spending is notable for most coal steam and gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Typical industry-standard frequencies for repairs and replacements of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.
- Vendor-specified major maintenance spending, such as commonly applied to gas/oil CC and gas/oil CTs, is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:
    - Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
    - Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

Potential Benefits of CAPEX and O&M Spending on Future Spending

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

Potential Impacts of Plant Age on Future Spending

The spending characteristics described in the previous subsections are evident in the datasets, which reveal significant variability in plant spending as a function of age. Sargent & Lundy's evaluation therefore examined additional variables that might explain some of the variability in age-related spending: plant capacity (MW), capacity factor, external market conditions, regulatory environment, fuel characteristics, and FGD. These additional variables and their effects are described in the following subsections.

Effect of Plant Capacity (MW)

The effect of plant MW capacity on age-related spending, expressed in $/kW-year, was examined by breaking the dataset into separate plant size categories, summarized as follows:

- Coal Steam
  - All MW
  - < 500 MW
  - 500 MW – 1,000 MW
  - 1,000 MW – 2,000 MW
  - > 2,000 MW
- Gas/Oil CC
  - All MW
  - < 500 MW
  - 500 MW – 1,000 MW
  - > 1,000 MW
- Conventional Hydroelectric
  - All MW
  - < 100 MW
  - 100 MW – 500 MW
  - > 500 MW
- Solar Photovoltaic
  - < 5 MW
  - > 5 MW
- Gas/Oil Steam
  - < 500 MW
  - 500 MW – 1,000 MW
  - > 1,000 MW
- Gas/Oil CT
  - All MW
  - < 100 MW
  - 100 MW – 300 MW
- Pumped Hydroelectric Storage
  - All MW
  - < 100 MW
  - 100 MW – 500 MW
  - > 500 MW
- Wind Turbine
  - All MW
  - < 100 MW
  - 100 MW – 200 MW
  - > 200 MW

For some of the MW breakdowns above, the age coefficient in the regression analysis of CAPEX or O&M was found to be statistically significant. For the other MW breakdowns, an average value by age group was found to be more appropriate (see Table ES-1).

Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure ES-1. A similar decline also occurred with the gas/oil steam plants, as shown in Figure ES-2.

Figure ES-1 — Capacity Factor vs. Age for All Coal Plants

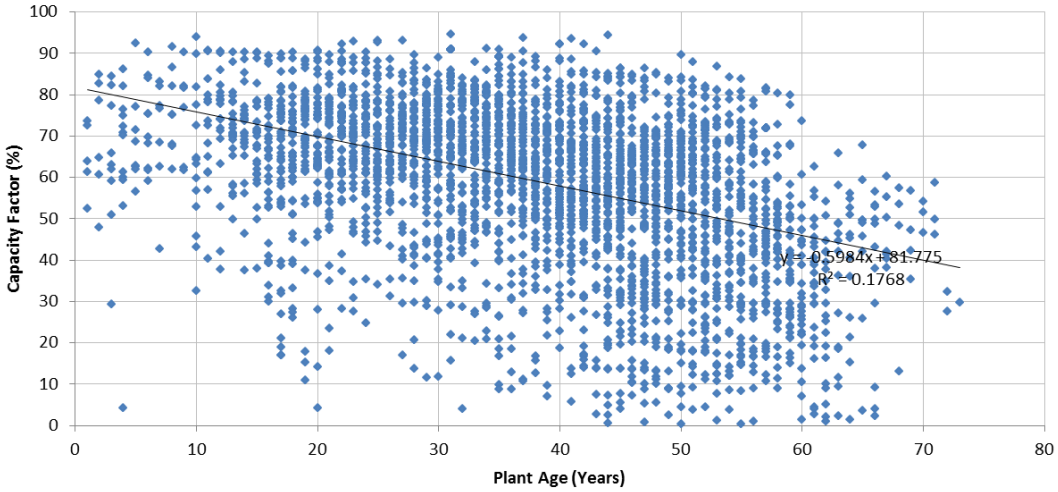
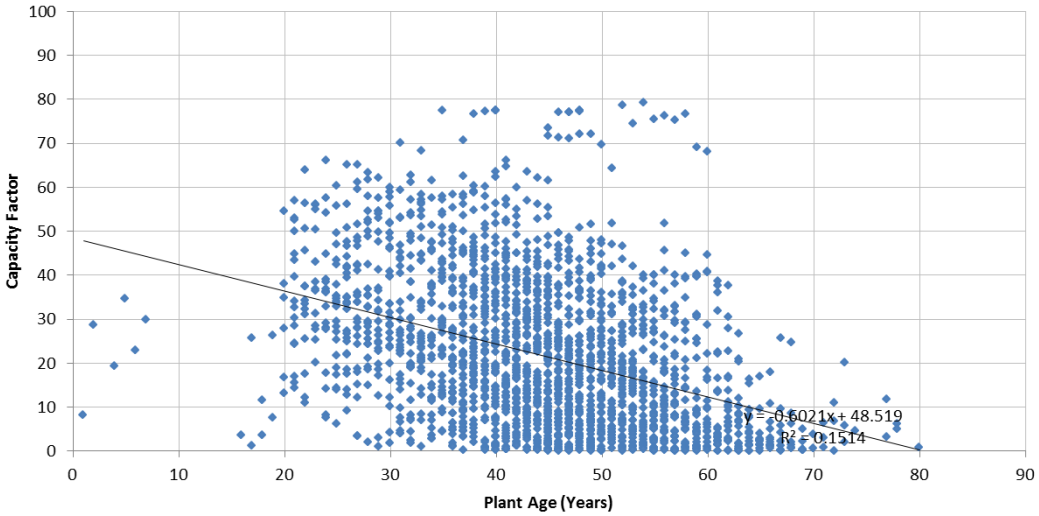


Figure ES-2 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



Effect of External Market Conditions

The declining capacity factors with age, shown above, may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam and gas/oil steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam and gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.[3]

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam and gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their plant lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table ES-2 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

[3] Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

Table ES-2 — High Capacity Factor Coal Plants – Spending Comparison

	Average – All Years	Years 1-20	Years 20-40	Years 40-80
Capacity Factor – All Plants	59.1%	66.8%	64.5%	52.9%
Capacity Factor – High CF Plants	74.0%	-	72.8%	74.4%
O&M – All Plants (2017 $/kW-yr)	46.01	53.90	40.06	48.77
CAPEX – All Plants (2017 $/kW-yr)	22.78	17.92	26.20	21.25
Total – All Plants (2017 $/kW-yr)	68.67	71.86	66.25	69.82
O&M – High CF Plants (2017 $/kW-yr)	36.65	-	31.07	38.78
CAPEX – High CF Plants (2017 $/kW-yr)	20.26	-	23.13	19.16
Total – High CF Plants (2017 $/kW-yr)	57.02	-	54.20	58.10

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states. Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types. The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

Effect of Flue Gas Desulfurization

The regression analysis indicated a significant difference in CAPEX spending for coal plants with FGD. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

PROPOSED UPDATES TO EMM METHODOLOGY

The EMM captures changes in age-related spending patterns through multiple cost categories: CAPEX, O&M, fuel, energy sales, and capacity sales. The updates below relate only to the CAPEX and O&M. The focus of the work scope was to more accurately represent power plant aging impacts on CAPEX and O&M. Detailed derivations of fixed and variable O&M costs for the EMM were not part of the work scope.

Sargent & Lundy's recommended updates to the fixed and variable O&M costs and CAPEX in the EMM for each generating technology are summarized in the tables below. Values are in constant 2017 price levels and are incurred in every year of plant operation, starting from commercial operation through plant retirement. In all cases, the yearly values would increase annually with the inflation rate.

Coal Steam

Sargent & Lundy's analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): age and FGD. Variables not having a significant effect on annual changes in real CAPEX spending (on a constant $/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-3 compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table ES-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors

Net Total CAPEX (2017 $/kW-year)	$/kW-yr (Years 1-10)	$/kW-yr (Years 10-20)	$/kW-yr (Years 20-30)	$/kW-yr (Years 30-40)	$/kW-yr (Years 40-50)	$/kW-yr (Years 50-60)	$/kW-yr (Years 60-70)	$/kW-yr (Years 70-80)
New Value – No FGD*	17.16	18.42	19.68	20.94	22.20	23.46	24.72	25.98
New Value – with FGD*	22.84	24.10	25.36	26.62	27.88	29.14	30.40	31.66
Existing EMM Value	17.55	17.55	17.55	24.62	24.62	24.62	24.62	24.62

*Calculated to the midpoint of the given age band.

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of

discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in $/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table ES-4).

Table ES-4 — Coal Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)**	Total O&M (2017 $/kW-yr)**
Coal Steam Dataset Results – All Plants	36.81	1.78	9.20	46.01
< 500 MW	44.21	1.78	9.20	53.41
500 MW – 1,000 MW	34.02	1.78	9.20	43.22
1,000 MW – 2,000 MW	28.52	1.78	9.20	37.72
> 2,000 MW	33.27	1.78	9.20	42.47
Existing EMM Value***	40.63	1.78	9.20	49.83

*Fixed and variable split is estimated using the existing EMM variable O&M cost of $1.78/MWh.
**Calculated at the coal steam dataset average capacity factor of 59%.
***Source: Internal communication with EIA, February 2018.

Gas/Oil Steam

The analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-5 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table ES-5 — Gas/Oil Steam CAPEX Results

Plant Size	Net Total CAPEX (2017 $/kW-year)	
	Years 1-30	Years 30-80
Gas/Oil Steam Dataset Results – All Plants	15.96	15.96
New Value: < 500 MW	18.86	18.86
New Value: 500 MW – 1,000 MW	11.57	11.57
New Value: > 1,000 MW	10.82	10.82
Existing EMM Value	9.14	16.21

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRAs are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table ES-6). However, the variable O&M of $8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of $1.78/MWh in the EMM used for the coal units.

Table ES-6 — Gas/Oil Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)**	Total O&M (2017 $/kW-yr)**
Gas/Oil Steam Dataset Results – All Plants	24.68	1.00	1.84	26.52
< 500 MW	29.73	1.00	1.84	31.57
500 MW – 1,000 MW	17.98	1.00	1.84	19.82
> 1,000 MW	14.51	1.00	1.84	16.35
Existing EMM Value***	19.68	8.23	15.14	34.82

*Fixed and variable split is estimated using an approximate value for variable O&M of $1.00/MWh based on confidential projects.
**Calculated at the gas/oil steam dataset average capacity factor of 21%.
***Source: Internal communication with EIA, February 2018.

Gas/Oil Combined Cycle and Gas/Oil Combustion Turbine

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC and gas/oil CT plants represents a series of capital projects throughout the plant life, which include projects for "life extension." Most CAPEX spending for gas/oil CC and gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs described in the previous subsection, major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table ES-7 compares the new CAPEX and O&M values derived from the gas/oil CC and CT datasets with the values currently used in the EMM. As indicated above, the combined CAPEX and O&M values in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC and CT plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of $7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the $/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

- The EMM fixed and variable O&M costs for CT plants are high for all plant sizes. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

Table ES-7 — Gas/Oil CC and CT CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)*	Total O&M (2017 $/kW-yr)*	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)**
CC Dataset Results (All Plants)	13.08	3.91	(included in CAPEX)	13.08	15.76	28.84
< 500 MW	15.62	4.31	(included in CAPEX)	15.62	17.38	33.00
500 MW – 1,000 MW	9.27	3.42	(included in CAPEX)	9.27	13.78	23.05
> 1,000 MW	11.68	3.37	(included in CAPEX)	11.68	13.57	25.25
Existing EMM Value**	27.52	2.64	10.64	38.16	0.18; 7.25 (after year 30)	38.34; 45.41 (after year 30)
CT Dataset Results (All Plants)	5.33	(starts based)	(included in CAPEX)	5.33	6.90	12.23
< 100 MW	5.96	(starts based)	(included in CAPEX)	5.96	9.00	14.96
100 MW – 300 MW	6.43	(starts based)	(included in CAPEX)	6.43	6.18	12.61
> 300 MW	3.99	(starts based)	(included in CAPEX)	3.99	6.95	10.94
Existing EMM Value***	12.60	14.63	5.13	17.73	1.52	19.25

*Fixed and variable split is estimated, assuming all CAPEX costs are represented as variable O&M, either hours-based ($/MWh) or starts-based ($/start).
**Calculated at the dataset average capacity factor of 46% for CC and 4% for CT.
***Source: Internal communication with EIA, February 2018.

Conventional Hydroelectric

Overall, the conventional hydroelectric dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. The average CAPEX value over all operating years is $22.56/kW-year. The dataset does support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 22.360 + (0.073 × age)

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table ES-8) and outside the range of values published in the AEO[4] and by the International Renewable Energy Agency (IRENA).[5] The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

Table ES-8 — Hydroelectric CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Conventional Hydroelectric Dataset Results – All Plants	22.00	-	22.56	44.56
Existing EMM Value*	14.58	0.00	0.00	14.58

*Source: Internal communication with EIA, February 2018.

Pumped Storage

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is $14.83/kW-year for CAPEX and $23.63/kW-year for O&M (Table ES-9). The existing values used in the EMM are not available.

Table ES-9 — Pumped Storage CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Pumped Storage Dataset Results – All Plants	23.63	-	14.83	38.46
Existing EMM Value	N/A	N/A	N/A	N/A

Solar Photovoltaic

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Sargent & Lundy notes that the average change in the "Total Cost of Plant" (TCP) reported in the FERC data for the limited usable dataset (15 sites not filtered out) is approximately $26/kW-year. However, due to the limited dataset, lack of clarity on what qualifies as a change to the TCP, and general lack of

[4] Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.
[5] International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series, Hydropower*, June 2012.

consistency in the FERC capital cost data provided, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based upon closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old.

When considering the average O&M costs per plant as a single data point and then averaging those values, Sargent & Lundy calculated an average O&M cost of $75/kW-year from the FERC data for sites under 5 MW. Using the same method, an average O&M cost of $15/kW-year was calculated from the FERC data for sites over 5 MW.

By comparison, the EMM uses an average O&M value of $28.47/kW-year for all solar PV plants and an average CAPEX value of zero. Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

Geothermal

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated $/kW-year average in Table ES-10 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

Table ES-10 — Geothermal CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Geothermal Dataset Results – All Plants	157.10	-	40.94	198.04
Existing EMM Value**	91.66	0.00	0.00	91.66

**Source: Internal communication with EIA, February 2018.

Wind

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table ES-11. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

Table ES-11 — Wind CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)
Wind Dataset Results – All Plants	31.66 + (1.22 × age)	0.00	18.29
< 100 MW	39.08 + (1.12 × age)	0.00	20.48
100 MW – 200 MW	23.80 + (1.17 × age)	0.00	16.93
> 200 MW	26.78 + (0.92 × age)	0.00	13.48
Existing EMM Value*	29.31	0.00	0.00

*Source: Internal communication with EIA, February 2018.

RECOMMENDED AREAS FOR FURTHER STUDY

Based on our analyses performed for the update to the EMM treatment of age-related spending, Sargent & Lundy identified several areas that warrant further study, including:

- Impact of regional labor cost differences versus the effects of a regulated/deregulated environment;
- Compatibility of EMM plant technology and size breakdowns and fixed/variable O&M cost breakdowns with proposed EMM updates;
- Identification of the factors supporting consistently high capacity factors over the plant lives at particular coal units; and
- Impact of aging on plant performance (heat rates, capacity derates, etc.). If capacity factors decline, regardless of the causes, this includes examining the impact of the lower capacity factors on plant costs and performance.

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1. INTRODUCTION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

This final report is the fourth milestone task of the EMM update project, which is organized as follows:

- Task 1 – Analysis of publicly available information for use in estimating capital costs related to ongoing operations for specified plant types.

- Task 2 – Analysis of publicly available information for use in estimating changes in O&M expenditures due to aging for specified plant types.
- Task 3 – Interim report on assembled aging-related capital and O&M costs.
- Task 4 – Final report on modeling aging-related capital and O&M costs.

2. ASSESSMENT METHODOLOGY

2.1 BACKGROUND

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX. These added expenditures are intended to extend the life or preserve the performance of an existing generator, including repowering, major repairs or retrofits, and/or covering increases in maintenance required to mitigate the adverse effects of aging, including any decreases in plant performance. The portion of the annual CAPEX associated with the step increase is referred as "life extension costs."

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is $0.18 per kilowatt-year (/kW-year) for existing CC plants, $9/kW-year for existing gas/oil steam plants, and $18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to $7.25/kW-year, $16/kW-year, and $25/kW-year, respectively, after a plant reaches 30 years of age.[6] The average annual CAPEX in the EMM for existing CT plants is $1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 ("FERC Form 1").[7] The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy's update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.

[6] Internal communication with EIA, February 2018.
[7] FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed ($/kW-year) or variable ($/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in the following subsections.

2.2 SOURCES OF COST INFORMATION

2.2.1 FERC Form 1 Data

Sargent & Lundy reviewed the FERC Form 1 data through 2016, financial information available from other publicly available sources, and detailed in-house project information with which we are familiar. We assembled a sufficient volume of source material for each technology in order to characterize the distribution of capital and O&M expenditures over the life of a plant.

We obtained the FERC Form 1 data via ABB's Velocity Suite EV Power database. Using the available FERC Form 1 data, we assessed and summarized the "Cost of Plant" components of the data by major plant type category. The "Cost of Plant" components include the following categories of "Electric Plant in Service" accounts in FERC Form 1 data, which have been reported annually since the database's inception:

- Steam Power Generation – Cost of Plant
    - 310 Land and land rights.
    - 311 Structures and improvements.

  - 312 Boiler plant equipment.
  - 313 Engines and engine-driven generators.
  - 314 Turbo generator units.
  - 315 Accessory electric equipment.
  - 316 Miscellaneous power plant equipment
  - 317 Asset retirement costs for steam production plant.
- Hydraulic Power Generation – Cost of Plant
  - 330 Land and land rights.
  - 331 Structures and improvements.
  - 332 Reservoirs, dams, and waterways.
  - 333 Water wheels, turbines, and generators.
  - 334 Accessory electric equipment.
  - 335 Miscellaneous power plant equipment.
  - 336 Roads, railroads, and bridges.
  - 337 Asset retirement costs for hydraulic production plant.
- Other Power Generation – Cost of Plant
  - 340 Land and land rights.
  - 341 Structures and improvements.
  - 342 Fuel holders, producers, and accessories.
  - 343 Prime movers.
  - 344 Generators.
  - 345 Accessory electric equipment.
  - 346 Miscellaneous power plant equipment.
  - 347 Asset retirement costs for other production plant.

The sum of these components includes the original construction cost and all ongoing CAPEX. Therefore, each annual FERC Form 1 submittal includes the cumulative additions to the "Total Cost of Plant" (TCP). Annual changes in the TCP between each submittal year give an indication of the amount of CAPEX for the given year. Sargent & Lundy assessed and summarized these annual changes to derive age-related CAPEX, as discussed in the following subsections.

Sargent & Lundy also assessed and summarized the annual O&M expenditures for each technology as reported under the "Electric Operation and Maintenance Expenses" accounts in FERC Form 1:

- Steam Power Generation – O&M
  - 500 Operation supervision and engineering.
  - 502 Steam expenses.
  - 505 Electric expenses.
  - 506 Miscellaneous steam power expenses.
  - 507 Rents.
  - 509 Allowances.
  - 510 Maintenance supervision and engineering.
  - 511 Maintenance of structures.
  - 512 Maintenance of boiler plant.
  - 513 Maintenance of electric plant.
  - 514 Maintenance of miscellaneous steam plant.
- Hydraulic Power Generation – O&M
  - 535 Operation supervision and engineering.
  - 536 Water for power.
  - 537 Hydraulic expenses.
  - 538 Electric expenses.
  - 539 Miscellaneous hydraulic power generation expenses.
  - 540 Rents.
  - 541 Maintenance supervision and engineering.
  - 542 Maintenance of structures.
  - 543 Maintenance of reservoirs, dams, and waterways.
  - 544 Maintenance of electric plant.
  - 545 Maintenance of miscellaneous hydraulic plant.
- Other Power Generation – O&M
  - 546 Operation supervision and engineering.
  - 548 Generation expenses.
  - 549 Miscellaneous other power generation expenses.
  - 550 Rents.
  - 551 Maintenance supervision and engineering.
  - 552 Maintenance of structures.
  - 553 Maintenance of generating and electric plant.
  - 554 Maintenance of miscellaneous other power generation plant.

The above O&M expenditures are reported for individual power plants. Administrative and general (A&G) expenses in FERC accounts 920 through 935 are reported for the entire utility company. A&G expenses in these accounts were not included in this evaluation because of the significant differences in company sizes, mix of resources, and methods of allocating costs to individual power plants. In a similar manner, corporate-level A&G costs were also excluded from Sargent & Lundy's internal data.

The above FERC accounts 500 to 554 correspond to the following fixed and variable O&M components:

- Fixed O&M
  - Labor
  - Maintenance materials
  - Supplies and miscellaneous expenses
- Variable O&M
  - Consumables (chemicals, water, waste disposal, etc.)
  - Other costs proportional to generating output

The FERC accounts do not explicitly break out labor costs, as most of the accounts include both labor and non-labor expenditures. Likewise, the FERC accounts are not categorized according to fixed and variable cost components. The O&M costs in a given account are combined fixed and variable costs at the reported generating output.

2.2.2 Sargent & Lundy Internal Data

In addition, Sargent & Lundy compared publicly available, non-fuel-related financial and cost data with a characterization of proprietary information with which we are familiar, to the extent permissible by applicable confidentiality agreements (information about plant location, equipment type, or plant configuration was never disclosed from the proprietary data). We utilized our knowledge of actual projects to assemble a characterization of life extension/repowering costs from our in-house data.

A large portion of the in-house data used in this report was developed from business plan forecasts that capture actual budgeted costs for scheduled projects as well as longer-term projections. Historical spending data for standalone projects was not usable for this analysis, unless Sargent & Lundy had access to the complete O&M or CAPEX spending totals at a given plant for a given year. For consistent comparisons with other plants over time, each O&M or CAPEX data point needed to represent a comprehensive total of all spending projects.

2.2.3 Other Data Sources

Other publicly available data sources were searched, including regulated utility filings with public utility commissions, routine financial reports for publicly traded companies, utility integrated resource plans, data reported by various municipalities and electric cooperatives, and requests for proposals (RFPs) for plant improvements at public power entities. Cost data from each of these sources was found to be unsuitable for this study for one or more of the following reasons:

- Cost data was for initial capital investment costs only, with no O&M or ongoing CAPEX spending reported;
- Annual O&M or annual CAPEX amounts were for limited purposes and not representative of a complete year; and/or
- Annual O&M and annual CAPEX amounts were aggregated across business units and not assigned to specific plants.

Several publications or studies of power plant aging and life extension costs were used, which are cited herein.

2.3 DATA VALIDATION

Sargent & Lundy's approach to validating the FERC Form 1 data involved the following steps (note that capitalized words are proper FERC Form 1 terms):

1. For each Plant/Prime Mover combination (e.g., steam turbine, CC, simple-cycle CT), determine the difference between the prior and current year TCP reported in the FERC data. Note that a plant can have multiple prime movers on site (e.g., CT units and steam turbine units). Fortunately, that data is reported separately.
2. Flag and invalidate any years where the difference is negative (i.e., a decreasing value of the TCP).
3. Identify if the TCP difference is significantly due to asset retirement costs. If so, flag this plant reporting year consider it invalid, as capital would have been spent on non-aging items.
4. Identify if there has been any year-to-year change in nameplate capacity. If so, flag this plant reporting year and consider it invalid, because the TCP would be assumed to be spent on an expansion or addition.
5. Identify if any sulfur dioxide (SO_2), nitrogen oxide (NO_X), particulate matter (PM), or mercury (Hg) control equipment was installed for the plant reporting year. If so, flag that plant reporting year and consider it invalid, because capital would have been spent on non-aging items. The year

prior to or after the actual emissions control installation date is sometimes flagged as well, because of when the spending occurred (this is usually a judgement call).

6. Identify if any unit at the plant has been retired in a plant reporting year. If so, flag that plant reporting year and consider invalid, because capital would have been spent on non-aging items. Also, if the plant's TCP dropped significantly the last few years before retirement, flag those plant reporting years and consider them invalid.
7. Cross-check if any additional units at the plant site (using the same technology) show too great of time duration between installed dates of the units. If the first unit and the last unit installed is greater than 10 years apart, then flag the data and consider it invalid, because the TCP difference would not reflect the actual age of the plant (considered to be the age of the first unit). This was flagged as "Removed due to non-equal units at site."
8. If any TCP is reported to be zero for most of all of the reporting years of the plant, consider the data invalid.
9. If the TCP difference is highly volatile, flag and invalidate at discretion. For example, if one year TCP drops from $2,000/kW-year to $1,000/kW-year and then back to $2,000/kW-year in the year after, this would be considered highly volatile for those two reporting years.
10. If a reporting plant has only one or two years of reported TCP data, flag the plant and do not use its data.
11. If any plant reports negative Total O&M Costs, flag that year and do not use it.
12. Use only data that is valid for both CAPEX spending and O&M spending in the analysis of combined CAPEX and O&M spending. Otherwise, analyze CAPEX spending and O&M spending separately. Sargent & Lundy found that a large portion of the data points determined to be valid for CAPEX spending were also valid for O&M spending.

The resulting data points from this validation process are summarized in Table 2-1.

For each year of plant data, we also compiled the associated nameplate capacity (MW) and annual generation (MWh). EIA Form 860 was used to confirm the plant technology, environmental equipment, year in service, and other attributes.

Table 2-1 — Summary of Valid Data Points

Technology / (Dataset Identifier)	Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
				O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
Coal (10)	All MW	All	3,713	3,098	3,109	655	615
	< 500 MW	All	1,592	1,274	1,284	318	318
	500 MW – 1,000 MW	All	986	689	689	337	297
	1000 MW – 2,000 MW	All	813	813	814	0	0
	> 2,000 MW	All	322	322	322	0	0
	All MW	< 50%	965	889	896	76	76
	All MW	> 50%	2,748	2,209	2,213	579	539
Gas/Oil Steam (20)	All MW	All	2,220	2,204	2,226	20	16
	< 500 MW	All	1,377	1,361	1,366	20	16
	500 MW – 1,000 MW	All	488	488	489	0	0
	> 1,000 MW	All	355	355	355	0	0
Gas/Oil Combined Cycle (30)	All MW	All	1,367	980	981	408	387
	< 500 MW	All	764	462	463	304	302
	500 MW – 1,000 MW	All	547	462	463	104	85
	> 1,000 MW	All	177	177	177	0	0
	All MW	< 50%	843	661	662	203	182
	All MW	> 50%	524	319	319	205	205
Gas/Oil Combustion Turbine (40)	All MW	All	5,041	4,905	4,949	437	136
	< 100 MW	All	2,873	2,873	2,911	189	0
	100 MW – 300 MW	All	1,341	1,239	1,248	177	102
	> 300 MW	All	901	867	875	71	34
Conventional Hydroelectric (50)	All MW	All	2,179	2,179	2,180	0	0
	< 100 MW	All	1,272	1,272	1,272	0	0
	100 MW – 500 MW	All	924	924	925	0	0
	> 500 MW	All	41	41	41	0	0

Technology / (Dataset Identifier)	Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
				O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
Pumped Storage Hydroelectric (55)	All MW	All	226	226	227	0	0
	< 100 MW	All	12	12	12	0	0
	100 MW – 500 MW	All	88	88	88	0	0
	> 500 MW	All	126	126	126	0	0
Solar Thermal (60)			0				
Solar Photovoltaic (65)	All MW	All	57	410	57	0	0
Geothermal (70)							
Wind Turbine (80)	All MW	All	310	310	310	270	0
	< 100 MW	All	174	174	174	165	0
	100 MW – 200 MW	All	91	91	91	56	0
	> 200 MW	All	51	51	51	73	0

Note: A data point is one reported value for one year by one plant, i.e., a plant that reports values for 25 years will have 25 data points.

2.4 DATA NORMALIZATION

Sargent & Lundy developed a Microsoft Excel model template for compiling and normalizing all of the CAPEX and O&M data, subsequent to the initial review and validation steps outlined in the previous sections. The data normalization consisted of the following steps:

Step 1: Assign data "identifiers" for each plant:

Technology ID:

- 10 = Coal Steam Plants
- 20 = Gas/Oil Steam Plants
- 30 = Gas/Oil CC Plants
- 40 = Gas/Oil CTs
- 50 = Conventional Hydropower; Pumped Storage – Hydraulic Turbine Reversible
- 60 = Solar Thermal – Central Tower;
- 65 = Solar PV – Single-Axis Tracking
- 70 = Geothermal
- 80 = Wind

Data source:

- 1 = FERC Form 1
- 2 = Sargent & Lundy Internal Data
- 3 = Other Public Source

Step 2: Enter basic information for each plant:

- Year of commercial operation date (COD)
- End year of project life or forecast period
- Nameplate capacity (MW)
- Summer net capacity (MW)

Step 3: Adjust pricing basis for raw data:

- If provided in current dollars, adjust to 2017 dollars
- If provided in 2017 dollars, do not adjust
- If provided in constant dollars of another reference year, adjust to 2017 dollars

Step 4: Enter annual data for each plant (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant MW (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

Using the inputs from Steps 1-4 above, the "Normalizer" worksheet derives the following for each plant:

- Annual O&M in 2017 $/kW-year versus age (years from COD)
- Annual CAPEX in 2017 $/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

The output worksheets ("O&M," "CAPEX," and "O&M + CAPEX") each have the following user-selected filters:

- Technology ID (10, 20, 30, etc.)

- Data source (1,2, or 3)
- MW range (low, high)
- Outlier maximum $/kW
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

Each output worksheet ("O&M," "CAPEX," and "O&M + CAPEX") calculates the following for a given user-defined set of filters:

- $/kW-year (2017 dollars) versus age
- Statistical tests of linear curve fit: annual spending in 2017 $/kW-year = $/kW-year (y-intercept) + [constant × age (years from COD)]
- Average $/kW-year (2017 dollars) for age bands (10-year bands, 30-year bands, and all-years band)

In all cases, the yearly values are expressed in constant 2017 price levels and increase annually with the inflation rate.

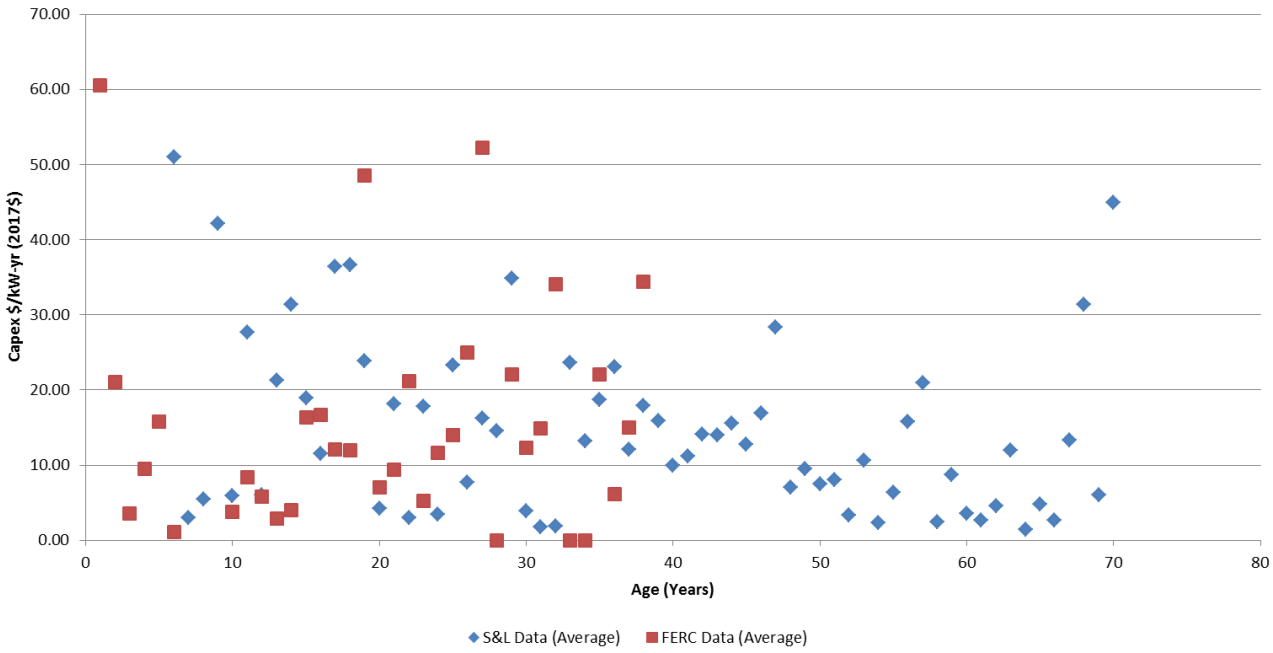
2.5 STATISTICAL TESTS

2.5.1 Consistency of FERC Form 1 and Sargent & Lundy Internal Data

FERC Form 1 data only covers historical data for utilities that are required to file and does not include the owners' projected expenditures or any data for merchant plants and independent power plants. Most of Sargent & Lundy's proprietary data, on the other hand, covers the owners' projected expenditures for utility plants and includes both historical and projected expenditures for merchant plants and independent power plants. The data points from both data sources were judged to be complementary and combined as a single dataset.

The compatibility of the FERC data and Sargent & Lundy internal data is illustrated by the CAPEX spending for a sample of 500-MW coal plants (Figure 2-1). This example is based on a sample of 11 plants from the Sargent & Lundy data and 12 plants from the FERC data, each sample having an average plant capacity of approximately 500 MW and an average age of approximately 30 years. Each data point in the figure is the average value for all the plants that have a valid data point at the given plant age. There are a total of 175 valid data points for the FERC plants and 200 valid data points for the Sargent & Lundy plants. In this particular sample, all of the FERC data is historical and all of the Sargent & Lundy data is owners' projected expenditures.

Figure 2-1 — CAPEX vs. Age for 500-MW Coal Plants – FERC and Sargent & Lundy Data



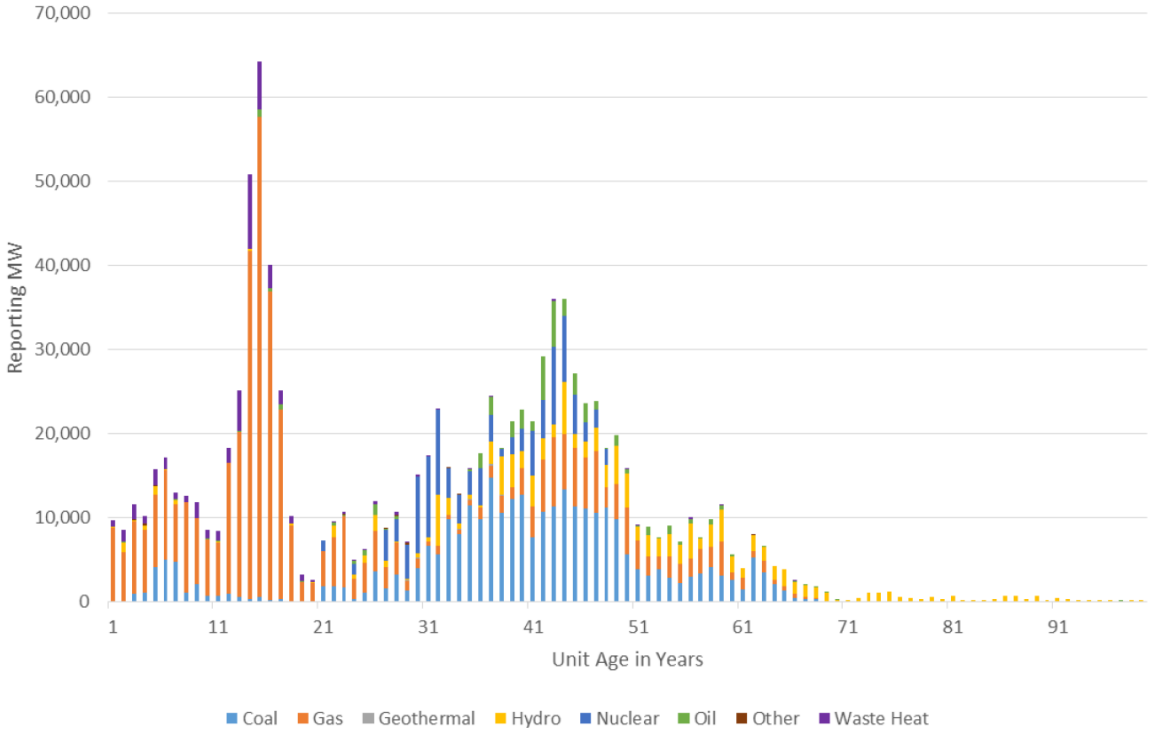
As discussed in Section 0, CAPEX spending for coal plants does not follow a uniform pattern for all plants. For example, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

For some utility plants, data was available from both FERC Form 1 and proprietary data. The historical O&M and CAPEX spending for these plants were examined in each year to verify their consistency.

The distribution of valid data points for each technology versus age (years from COD in which the spending occurs) was examined to verify consistency with typical plant ages nationwide. Figure 2-2 shows a recent distribution of the U.S. power plant fleet by unit age and fuel type as reported by FERC[8]. This distribution indicates a large portion of coal-fired capacity with ages of 30-50 years, and a large portion of gas-fired capacity (mostly CT or CC) with ages under 20 years. The valid data points assembled in this report were found to be representative of these major age and technology cohorts.

[8] North American Electric Reliability Corporation, *State of Reliability 2017*, June 2017 (p.116)

Figure 2-2 — U.S. Power Plant Fleet Capacity by Age and Fuel Type



A recent study found that the average age of the U.S. generator fleet has increased significantly over time, due in part to regulatory uncertainty in a deregulated market environment. At the same time, the average expected physical life of the fleet has been decreasing as a result of new investments in smaller, shorter-lived capacity. This has been a means of mitigating the regulatory risk of more limited stranded cost recovery mechanisms.[9] In another recent study, this one on the causes of power plant retirements, the strongest predictors of retirements were found to be SO_2 emission rates, planning reserve margins, variations in load growth or contraction, the age of older thermal plants, the ratio of coal to gas prices, and delivered natural gas prices. The impacts of annual CAPEX and O&M spending on retirement decisions were not specifically identified.[10]

2.5.2 Significance of Plant Age on Annual Capital and O&M Expenditures

For each technology group, Sargent & Lundy performed a regression analysis on the O&M spending, CAPEX spending, and combined O&M plus CAPEX spending using the following linear equation:

- Annual spending in 2017 $/kW-year = $/kW-year (y-intercept) + (constant × age)

[9] Rode, D., Fischbeck, P., and Paez, A., "Power Plant Lives and their Policy Implications," *Energy Policy*, 106 (2017) 222-232, April 1, 2017.
[10] Mills, A., Wiser, R., and Seel, J, "Power Plant Retirements: Trends and Possible Drivers," Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, November 2017.

The purpose of the regression analysis was to determine whether plant age is a statistically significant predictor of annual spending. The regression coefficient for age measures the change (+ or -) in annual spending as a function of plant age, measured as the number of years from the COD. Its statistical significance is measured by the p-value, which tests the null hypothesis that the coefficient is equal to zero (i.e., has no effect on spending).

The R-squared (R^2) statistic ("coefficient of determination") is an indication of the goodness of fit of the regression equation to the real data points. A low R^2 indicates that the regression equation explains a relatively small amount of the variability of the data around its mean. A low p-value (< 0.05) indicates that the age coefficient is statistically significant, regardless of the R^2 statistic. A low p-value corresponds approximately to a t-value that is greater than 2 or less than -2. For higher p-values, the simple average $/kW-year per year may be a more appropriate estimation for a given age band (e.g., 20-year bands and all-years band). Depending on the characteristics of the dataset, especially the number of data points, Sargent & Lundy applied engineering judgement (as further described in each section that follows) in our recommendations.

2.5.3 Autocorrelation of Time Series Data

In addition to the correlation between annual spending and plant age, an autocorrelation may also exist between spending in a given year and spending in previous years. Autocorrelation commonly occurs with time series data. If statistical tests verify the presence of autocorrelation, a lagged (autoregressive) variable may be added to improve the goodness of fit (R^2) of the regression model. Models with this functional form are referred to as "autoregressive integrated moving average" (ARIMA) models.

ARIMA models are typically constructed for the purpose of predicting the future from a given point in time, based on correlations with historical values and other exogenous variables. The functional form of an ARIMA model may better capture curvilinear or cyclical data trends and therefore improve the goodness of fit. For the purposes of this study, an ARIMA model was not necessary or appropriate. The datasets in this analysis already capture plant O&M and CAPEX spending patterns throughout a typical plant lifespan. The purpose of this study was to represent costs for generators as they age, and not to predict future spending from a given point in time.

3. COAL STEAM

3.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for coal steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M expenditures:
  - 456 plants in FERC data and 32 plants from Sargent & Lundy internal data
  - 3,098 valid data points in FERC data, 655 valid data points in Sargent & Lundy internal data
- CAPEX:
  - 457 plants in FERC data and 29 plants from Sargent & Lundy internal data
  - 3,109 valid data points in FERC data, 615 valid data points in Sargent & Lundy internal data

The coal steam data was broken down by plant MW capacity and average capacity factor—as summarized in Table 3-1—for the regression analysis shown in Appendix A.

Table 3-1 — Coal Steam Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	3,713	3,098	3,109	655	615
< 500 MW	All	1,592	1,274	1,284	318	318
500 MW – 1,000 MW	All	986	689	689	337	297
1,000 MW – 2,000 MW	All	813	813	814	0	0
> 2,000 MW	All	322	322	322	0	0
All MW	< 50%	965	889	896	76	76
All MW	> 50%	2,748	2,209	2,213	579	539

Table 3-2 below identifies the relative effects in the data validation process of the top three data filters on the number of valid data points. These filters are described as follows:

- Change in Capacity: A change in nameplate capacity of 20% or more during the reported time of the unit. Data points prior to the change in capacity are no longer comparable to the data points after the change in capacity, so the entire unit was filtered out.
- Negative Change in Total Cost: Any year with a decrease in the cumulative historical capital cost reported in the FERC data was not included.
- Environmental Retrofit: Data points in years where SO_2, NO_X, PM, or Hg removal equipment was installed were filtered out.

Table 3-2 — Effect of Data Validation Filters on Coal Data Points

Coal Steam – FERC Dataset	Data Points
Total Data Points, Unfiltered	6,699
Total Data Points, Filtered Out	3,774
Top Three Filters	
Change in Capacity	1,659
Negative Change in Total Cost	889
Environmental Retrofit	599
Total Data Points, Valid (FERC Only)	**2,925**

3.2 SUMMARY OF RESULTS

3.2.1 Recommended CAPEX Values

The analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): age and flue gas desulfurization (FGD). Variables not having a significant effect on annual changes in real CAPEX spending (on a constant $/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 3-3 below compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table 3-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors

Net Total CAPEX (2017 $/kW-year)	$/kW-yr (Years 1-10)	$/kW-yr (Years 10-20)	$/kW-yr (Years 20-30)	$/kW-yr (Years 30-40)	$/kW-yr (Years 40-50)	$/kW-yr (Years 50-60)	$/kW-yr (Years 60-70)	$/kW-yr (Years 70-80)
New Value – No FGD*	17.16	18.42	19.68	20.94	22.20	23.46	24.72	25.98
New Value – with FGD*	22.84	24.10	25.36	26.62	27.88	29.14	30.40	31.66
Existing EMM Value	17.55	17.55	17.55	24.62	24.62	24.62	24.62	24.62

*Calculated from the following regression equation to the midpoint of the given age band:

Annual CAPEX spending in 2017 $/kW-year = 16.53 + (0.126 × age) + (5.68 × FGD)
Where FGD = 1 if a plant has FGD; zero otherwise

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently compared with plants without FGD.

Table 3-4 below provides indicative typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant.

Table 3-4 — Coal Plant Indicative Typical CAPEX Projects and Intervals

Project Description	Typical Frequency of Repairs/Replacement from COD (Years)
Boiler	
Coal mills and exhausters, burner tips and ignitors	5
Lower nose tube, burner panels, economizer banks, air heater tubes, and baskets	15
Lower and upper waterwalls, superheater and reheater horizontal sections and pendants, economizer header, coal feeders, mill motors	20
Superheater and reheater header, feedwater supply piping	25
Mud and steam drums	30
Turbine and Generator	
Control valves, nozzle block	12
Electro-hydraulic control system (EHC), governor, turbine controls, generator rotor, turbine lubrication pumps	15
Stop valves, low-pressure (LP) turbine and blades, LP casing/diaphragms,	20
Steam chest, high-pressure/intermediate-pressure (HP/IP) turbine with blades, HP/IP casing/diaphragm, generator stator, exciter	25
HP/IP rotor, LP rotor, isophase	30
Balance of Plant	
Condensate pumps, cooling tower fill, cooling tower fan drives and blades, conveyor belts, conveyer idlers/pulleys/motors, coal crushing equipment	10
Slag conveyors and tanks	12
Induced draft (ID) fans, electrostatic precipitator (ESP) casing, ESP plates/wires, deaerator, circulating water pumps, boiler feed pumps, distributed control system (DCS)/unit controls, boiler master/combustion controls, coal handling dust control system	15
Forced draft (FD) fans, primary air (PA) fans, fan motors, windbox and ductwork, ESP transformer/rectifier (TR) sets and rappers, condenser valves and cleaner system, LP feedwater heaters, HP feedwater heaters, gland coolers, conveyor structures, coal unloading equipment, fuel oil heaters, and delivery pumps	20
Condenser retube, deaerator storage tank, vacuum pumps/steam air ejectors, pump motors	25
Main power transformer, auxiliary transformer	30

3.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while

variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in $/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (Table 3-5).

Table 3-5 — Coal Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)**	Total O&M (2017 $/kW-yr)**
Coal Steam Dataset Results – All Plants	36.81	1.78	9.20	46.01
< 500 MW	44.21	1.78	9.20	53.41
500 MW – 1,000 MW	34.02	1.78	9.20	43.22
1,000 MW – 2,000 MW	28.52	1.78	9.20	37.72
> 2,000 MW	33.27	1.78	9.20	42.47
Existing EMM Value***	40.63	1.78	9.20	49.83

*Fixed and variable split is estimated using the existing EMM variable O&M cost of $1.78/MWh.
**Calculated at the coal steam dataset average capacity factor of 59%.
***Source: Internal communication with EIA, February 2018.

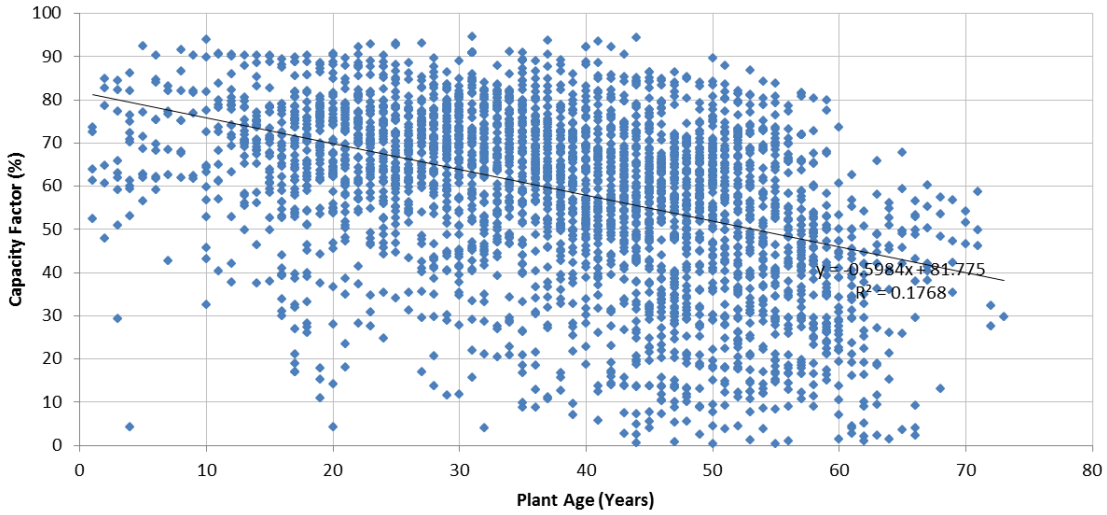
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

3.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 3-1.

Figure 3-1 — Capacity Factor vs. Age for All Coal Plants



3.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.[11]

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam plants would likely retire under the following circumstances:

[11] Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table 3-6 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

Table 3-6 — High Capacity Factor Coal Plants – Spending Comparison

	Average – All Years	Years 1-20	Years 20-40	Years 40-80
Capacity Factor – All Plants	59.1%	66.8%	64.5%	52.9%
Capacity Factor – High CF Plants	74.0%	-	72.8%	74.4%
O&M – All Plants (2017 $/kW-yr)	46.01	53.90	40.06	48.77
CAPEX – All Plants (2017 $/kW-yr)	22.78	17.92	26.20	21.25
Total – All Plants (2017 $/kW-yr)	68.67	71.86	66.25	69.82
O&M – High CF Plants (2017 $/kW-yr)	36.65	-	31.07	38.78
CAPEX – High CF Plants (2017 $/kW-yr)	20.26	-	23.13	19.16
Total – High CF Plants (2017 $/kW-yr)	57.02	-	54.20	58.10

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

3.2.5 Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states (see Appendix A). Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in

deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

3.2.6 Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types (Appendix A). The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

4. GAS/OIL STEAM

4.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 283 plants in FERC data and four plants from Sargent & Lundy internal data
  - 2,204 valid data points in FERC data, 20 valid data points in Sargent & Lundy internal data
- CAPEX
  - 283 plants in FERC data and four plants from Sargent & Lundy internal data
  - 2,226 valid data points in FERC data, 16 valid data points in Sargent & Lundy internal data

The gas/oil steam data was broken down by plant MW capacity, as summarized below in Table 4-1, for the regression analysis shown in Appendix B.

Table 4-1 — Gas/Oil Steam Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	2,220	2,204	2,226	20	16
< 500 MW	All	1,377	1,361	1,366	20	16
500 MW – 1,000 MW	All	488	488	489	0	0
> 1,000 MW	All	355	355	355	0	0

4.2 SUMMARY OF RESULTS

4.2.1 Recommended CAPEX Values

Sargent & Lundy's analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 4-2 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table 4-2 — Gas/Oil Steam CAPEX Results

Plant Size	Net Total CAPEX (2017 $/kW-year)	
	Years 1-30	Years 30-80
Gas/Oil Steam Dataset Results – All Plants	15.96	15.96
New Value: < 500 MW	18.86	18.86
New Value: 500 MW – 1,000 MW	11.57	11.57
New Value: > 1,000 MW	10.82	10.82
Existing EMM Value	9.14	16.21

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair. Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRAs are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term

maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

4.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table 4-3). However, the variable O&M of $8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of $1.78/MWh in the EMM used for the coal units.

Table 4-3 — Gas/Oil Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)*	Variable O&M (2017 $/kW-yr)**	Total O&M (2017 $/kW-yr)**
Gas/Oil Steam Dataset Results – All Plants	24.68	1.00	1.84	26.52
< 500 MW	29.73	1.00	1.84	31.57
500 MW – 1,000 MW	17.98	1.00	1.84	19.82
> 1,000 MW	14.51	1.00	1.84	16.35
Existing EMM Value***	19.68	8.23	15.14	34.82

*Fixed and variable split is estimated using an approximate value for variable O&M of $1.00/MWh based on confidential projects.
**Calculated at the gas/oil steam dataset average capacity factor of 21%.
***Source: Internal communication with EIA, February 2018.

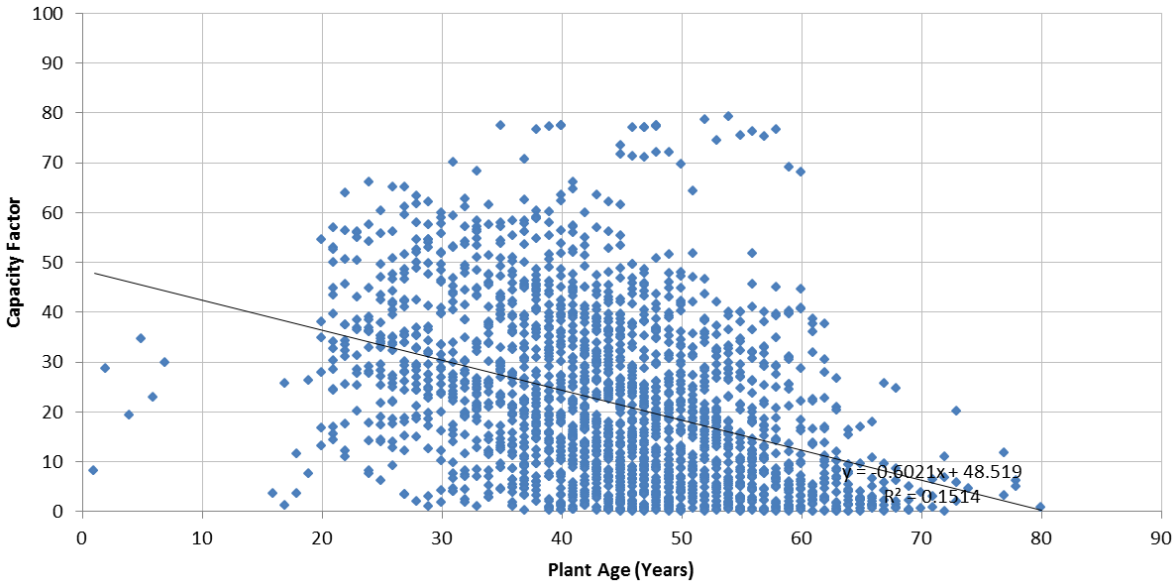
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

4.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the gas/oil steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 4-1.

Figure 4-1 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



4.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for gas/oil steam plants include:

- Competition with more efficient gas turbines

- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

5. GAS/OIL COMBINED CYCLE

5.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CC plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 144 plants in FERC data and 20 plants from Sargent & Lundy internal data
  - 980 valid data points in FERC data, 408 valid data points in Sargent & Lundy internal data
- CAPEX
  - 142 plants in FERC data and 17 Sargent & Lundy proprietary plants with valid data
  - 981 valid data points in FERC data, 387 valid data points in Sargent & Lundy internal data

The gas/oil CC data was broken down by plant MW capacity and average capacity factor, as summarized below in Table 5-1, for the regression analysis shown in Appendix C.

Table 5-1 — Gas/Oil CC Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	1,367	980	981	408	387
< 500 MW	All	764	462	463	304	302
500 MW – 1,000 MW	All	547	462	463	104	85
> 1,000 MW	All	177	177	177	0	0
All MW	< 50%	843	661	662	203	182
All MW	> 50%	524	319	319	205	205

5.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC plants represents a series of capital projects throughout the plant life, which includes projects for "life extension." Most CAPEX spending for gas/oil CC plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table 5-2 compares the new CAPEX and O&M values derived from the gas/oil CC dataset with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the dataset would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of $7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the $/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

Table 5-2 — Gas/Oil CC CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	Variable O&M (2017 $/kW-yr)*	Total O&M (2017 $/kW-yr)*	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)*
CC Dataset Results – All Plants	13.08	3.91	(included in CAPEX)	13.08	15.76	28.84
< 500 MW	15.62	4.31	(included in CAPEX)	15.62	17.38	33.00
500 MW – 1,000 MW	9.27	3.42	(included in CAPEX)	9.27	13.78	23.05
> 1,000 MW	11.68	3.37	(included in CAPEX)	11.68	13.57	25.25
Existing EMM Value**	27.52	2.64	10.64	38.16	0.18; 7.25 (after year 30)	38.34; 45.41 (after year 30)

*Calculated at the gas/oil CC dataset average capacity factor of 46%. Fixed and variable O&M split is estimated.
**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

6. GAS/OIL COMBUSTION TURBINE

6.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CT plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 625 plants from FERC data and 27 plants from Sargent & Lundy internal data
  - 4,905 valid data points in FERC data, 437 valid data points in Sargent & Lundy internal data
- CAPEX
  - 579 plants from FERC data and five plants from Sargent & Lundy internal data
  - 4,949 valid data points in FERC data, 136 valid data points in Sargent & Lundy internal data

The CT data was broken down by plant MW capacity, as summarized below in Table 6-1, for the regression analysis shown in Appendix D.

Table 6-1 — Gas/Oil Combustion Turbine Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	5,041	4,905	4,949	437	136
< 100 MW	All	2,873	2,873	2,911	189	0
100 MW – 300 MW	All	1,341	1,239	1,248	177	102
> 300 MW	All	901	867	875	71	34

6.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CT plants represents a series of capital projects throughout the plant life, which includes projects for "life extension." Most CAPEX spending for gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CTs is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table 6-2 compares the new CAPEX and O&M values derived from the gas/oil CT datasets with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, EMM fixed and variable O&M costs across all plant sizes are higher than values Sargent & Lundy has observed in actual CT plants. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

Table 6-2 — Gas/Oil Combustion Turbine CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	Variable O&M (2017 $/kW-yr)*	Total O&M (2017 $/kW-yr)*	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)*
CT Dataset Results – All Plants	5.33	(starts based)	(included in CAPEX)	5.33	6.90	12.23
< 100 MW	5.96	(starts based)	(included in CAPEX)	5.96	9.00	14.96
100 MW – 300 MW	6.43	(starts based)	(included in CAPEX)	6.43	6.18	12.61
> 300 MW	3.99	(starts based)	(included in CAPEX)	3.99	6.95	10.94
Existing EMM Value**	12.60	14.63	5.13	17.73	1.52	19.25

*Calculated at the gas/oil CC dataset average capacity factor of 4%.
**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

7. CONVENTIONAL HYDROELECTRIC

7.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for conventional hydroelectric plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 348 plants in FERC data
  - 2,179 valid data points in FERC data
- CAPEX
  - 348 plants in FERC data
  - 2,180 valid data points in FERC data

The conventional hydroelectric data was broken down by plant MW capacity, as summarized below in Table 7-1, for the regression analysis shown in Appendix E.

Table 7-1 — Conventional Hydroelectric Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	2,179	2,179	2,180	0	0
< 100 MW	All	1,272	1,272	1,272	0	0
100 MW – 500 MW	All	924	924	925	0	0
> 500 MW	All	41	41	41	0	0

7.2 SUMMARY OF RESULTS

Sargent & Lundy's linear regression analysis of the dataset for conventional hydroelectric plants (Appendix E) supports age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). CAPEX spending for this dataset may be estimated by the regression equation:

Annual CAPEX spending in 2017 $/kW-year = 7.269 + (0.296 × age)

The dataset also supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 22.360 + (0.073 × age)

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table 7-2) and outside the range of values published in the AEO[12] and by the International Renewable Energy Agency (IRENA).[13] The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

Table 7-2 — Hydroelectric CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Conventional Hydroelectric Dataset Results – All Plants	22.00	-	22.56	44.56
Existing EMM Value*	14.58	0.00	0.00	14.58

*Source: Internal communication with EIA, February 2018.

[12] Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.
[13] International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series, Hydropower*, June 2012.

8. PUMPED HYDROELECTRIC STORAGE

8.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for pumped storage plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 37 plants in FERC data
  - 226 valid data points in FERC data
- CAPEX
  - 37 plants in FERC data
  - 227 valid data points in FERC data

The pumped storage data was broken down by plant MW capacity, as summarized below in Table 8-1, for the regression analysis shown in Appendix F.

Table 8-1 — Pumped Storage Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	226	226	227	0	0
< 100 MW	All	12	12	12	0	0
100 MW – 500 MW	All	88	88	88	0	0
> 500 MW	All	126	126	126	0	0

8.2 SUMMARY OF RESULTS

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is $14.83/kW-year for CAPEX and $23.63/kW-year for O&M (Table 8-2). The existing values used in the EMM are not available.

Table 8-2 — Pumped Storage CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Pumped Storage Dataset Results – All Plants	23.63	-	14.83	38.46
Existing EMM Value	N/A	N/A	N/A	N/A

9. SOLAR PHOTOVOLTAIC

9.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for solar PV storage plants were compiled using the assessment methodology described in Section 2. The FERC data includes 105 solar PV installations ranging in capacity from 10 kW to 36 MW.

The solar PV data, summarized below in Table 9-1, was used for the regression analysis shown in Appendix G.

Table 9-1 — Solar Photovoltaic Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	57	410	57	0	0

9.2 SUMMARY OF RESULTS

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size (see Appendix G). Sargent & Lundy determined that a significant portion of the data needed to be filtered out, resulting in a limited dataset of 15 sites. The average annual CAPEX (i.e., change in TCP) for these sites was approximately $26/kW-year. However, due to the limitations of the solar PV dataset, described in Appendix G, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based on a closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old and the fact that nearly all data points for plants over 10 years old are reported as having zero O&M expenses. Additionally, many of these plants also reported zero O&M expenses for all years of operation.

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment,

inspecting modules for damage, inspecting mounting systems, and checking invertor settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

An average O&M cost of $75/kW-year was calculated from the FERC data for sites under 5 MW, and $15/kW-year for sites over 5 MW. Sargent & Lundy notes that, compared to other industry metrics shown in Appendix G, the FERC data averages are similar for the sites over 5 MW but much higher for the sites under 5 MW.

If the results of the regression analysis are used, the average O&M costs are reduced to $41/kW-year for sites under 5 MW and $10/kW-year for sites over 5 MW. The regression analysis uses each year of plant data as a unique data point, which captures the years in which zero O&M costs were reported.

By comparison, the EMM uses an average O&M value of $28.47/kW-year for all solar PV plants and an average CAPEX value of zero.[14] Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

[14] Internal communication with EIA, February 2018.

10. SOLAR THERMAL

10.1 DATA DESCRIPTION

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

10.2 SUMMARY OF RESULTS

The U.S. National Renewable Energy Laboratory (NREL) published an Annual Technology Baseline (ATB) in 2017 that estimates the capital and O&M cost of a 100-MWnet solar power tower plant with 10 hours of thermal storage, based on cost models benchmarked with industry data.[15] The estimate includes future projections based on possible reductions in costs (high, mid, or low). The 2017 ATB includes a 2015 baseline. An update is expected to be made available in 2018.

[15] NREL 2017 Annual Technology Baseline (https://atb.nrel.gov/electricity/2017/index.html?t=sc)

11. GEOTHERMAL

11.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for geothermal plants were compiled using the assessment methodology described in Section 2. The FERC data includes five geothermal installations ranging in capacity from 23 MW to 1,224 MW.

The geothermal data summarized in Table 11-1 was used for the regression analysis shown in Appendix I.

Table 11-1 — Geothermal Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	36	38	36	0	0

11.2 SUMMARY OF RESULTS

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated $/kW-year average in Table 11-2 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

Table 11-2 — Geothermal CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)	Total O&M and CAPEX (2017 $/kW-yr)
Geothermal Dataset Results – All Plants	157.10	-	40.94	198.04
Existing EMM Value*	91.66	0.00	0.00	91.66

*Source: Internal communication with EIA, February 2018.

12. WIND

12.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for wind plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 73 plants in FERC and 24 from Sargent & Lundy proprietary plants with valid data
  - 310 valid data points in FERC, 270 valid data points in Sargent & Lundy proprietary plants
- CAPEX
  - 97 plants in FERC with valid data
  - 310 valid data points in FERC

Sargent & Lundy's dataset includes both actual historical cost reporting from operating wind projects as well as forecasted budgetary cost projections prepared by project developers and operators with large project portfolios.

Operating costs are assumed to include all expenses related to the maintenance of the wind project, such as planned and unplanned maintenance of the wind turbines and electrical balance of plant (including labor, parts, materials, and consumables) as well as operating expenses (such as facility monitoring and management fees, utilities, land lease and royalty payments, professional service fees, taxes, and insurance).

The wind data was broken down by plant MW capacity, as summarized below in Table 12-1, for the regression analysis shown in Appendix J.

Table 12-1 — Wind Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	310	310	310	270	0
< 100 MW	All	174	174	174	165	0
100 MW – 200 MW	All	91	91	91	56	0
> 200 MW	All	51	51	51	73	0

12.2 SUMMARY OF RESULTS

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table 12-2. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

Table 12-2 — Wind CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 $/kW-yr)	Variable O&M (2017 $/MWh)	CAPEX (2017 $/kW-yr)
Wind Dataset Results – All Plants	31.66 + (1.22 × age)	0.00	18.29
< 100 MW	39.08 + (1.12 × age)	0.00	20.48
100 MW – 200 MW	23.80 + (1.17 × age)	0.00	16.93
> 200 MW	26.78 + (0.92 × age)	0.00	13.48
Existing EMM Value*	29.31	0.00	0.00

*Source: Internal communication with EIA, February 2018.

Appendix A. Regression Analysis – Coal Steam

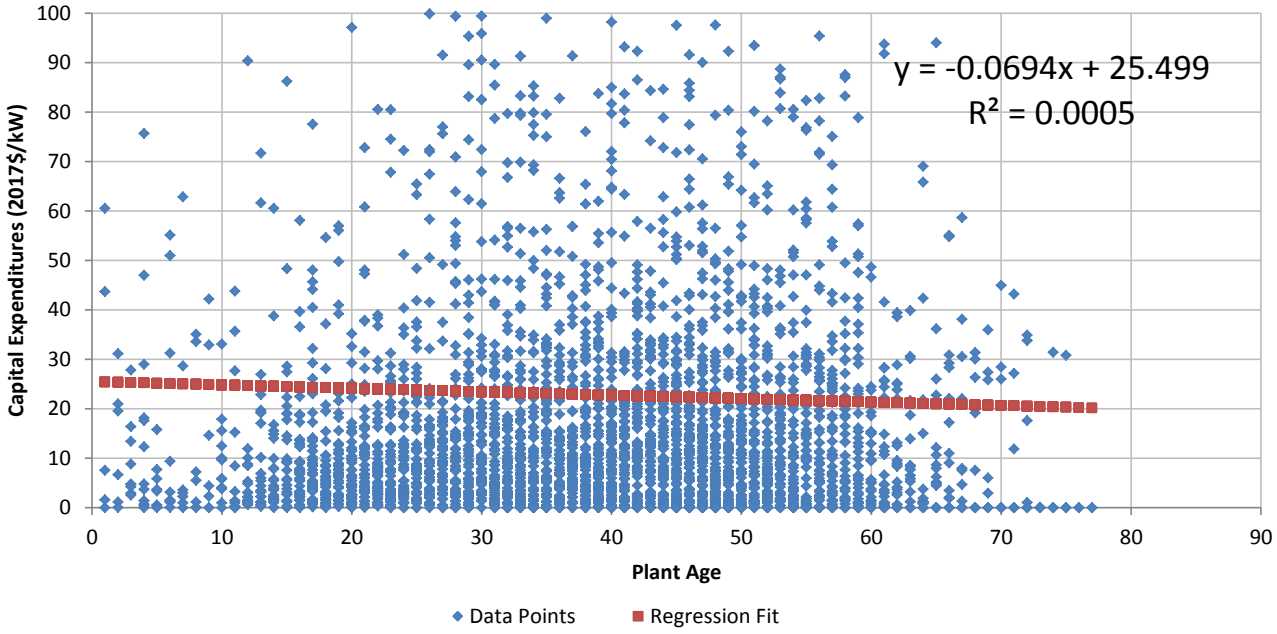
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.19, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, age and FGD are significant variables when an FGD variable is added to the regression equation (see below).

Table A-1 — Regression Statistics – Coal CAPEX for All MW

		t statistic	*p-value*
Observations	3,724		
Simple Average ($/kW)	22.782		
Intercept	25.499	11.4859	4.95E-30
Slope	-0.069	-1.3054	1.92E-01
R^2	0.00046		

Figure A-1 — Coal Steam Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

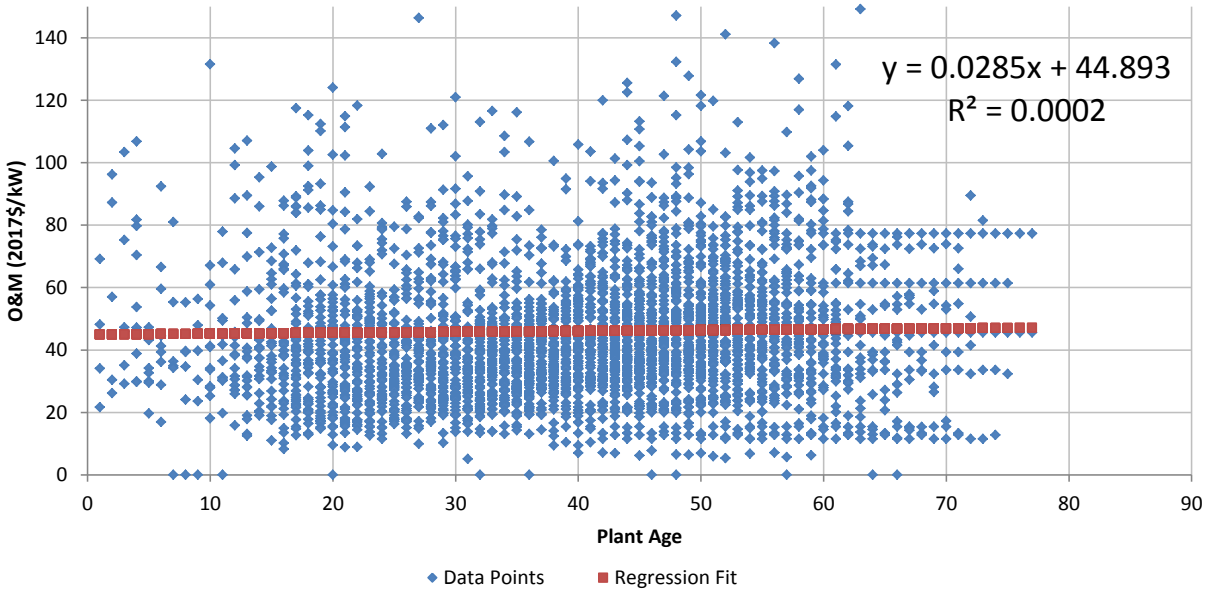
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.38, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table A-2 — Regression Statistics – Coal O&M for All MW

		t statistic	*p-value*
Observations	3,753		
Simple Average ($/kW)	46.013		
Intercept	44.893	33.2097	3.08E-212
Slope	0.028	0.8843	3.77E-01
R^2	0.00021		

Figure A-2 — Coal Steam Dataset – O&M for All MW Plant Sizes



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	53.90	40.06	48.77	**46.01**	440	1,448	1,865	**3,753**
Net Total Capex - 2017 $/kW	17.92	26.20	21.25	**22.78**	441	1,450	1,833	**3,724**
Net Total O&M and Capex - 2017 $/kW	71.86	66.25	69.82	**68.67**	440	1,448	1,825	**3,713**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

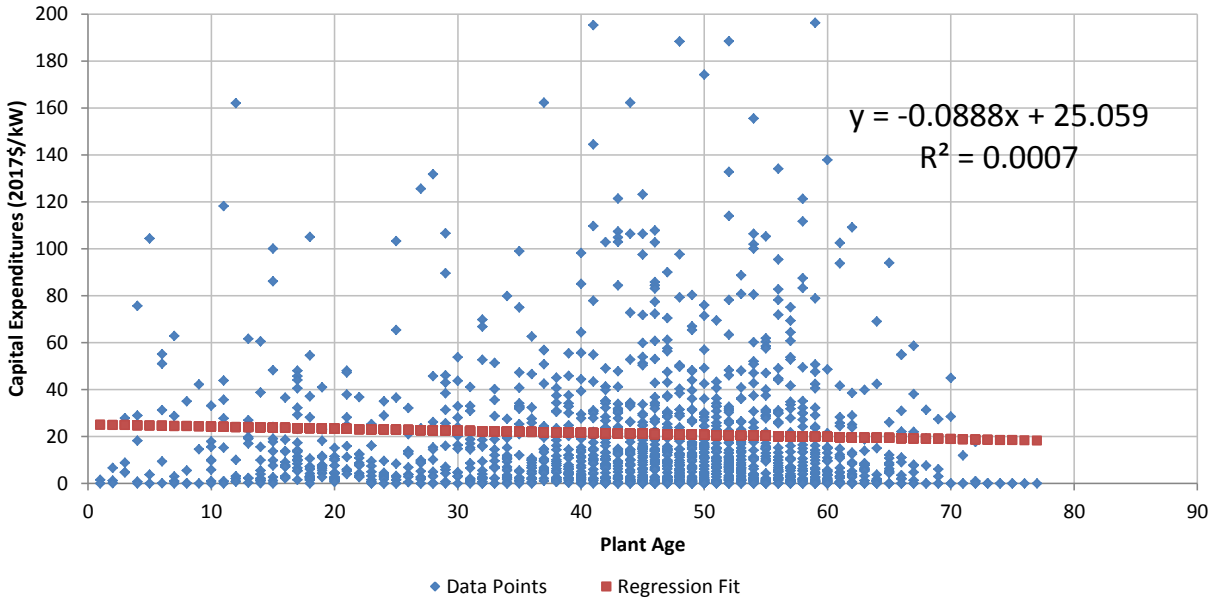
CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.28, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table A-3 — Regression Statistics – Coal CAPEX < 500 MW

		t statistic	***p-value***
Observations	1,602		
Simple Average ($/kW)	21.187		
Intercept	25.059	6.5593	7.28E-11
Slope	-0.089	-1.0685	2.85E-01
R^2	0.00071		

Figure A-3 — Coal Steam Dataset – CAPEX for Less than 500-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

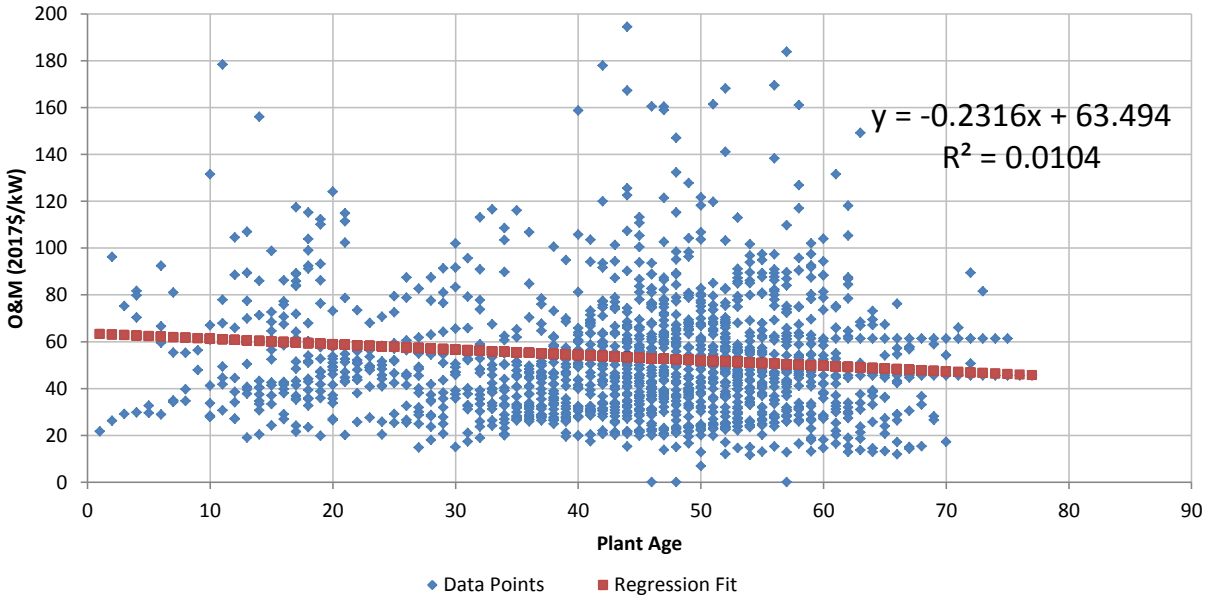
The results of the regression analysis of O&M spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the following regression equation:

Annual spending in 2017 $/kW-year = 63.494 + (-0.232 × age)

Table A-4 — Regression Statistics – Coal O&M < 500 MW

		t statistic	*p-value*
Observations	1,592		
Simple Average ($/kW)	53.406		
Intercept	63.494	24.4603	2.03E-112
Slope	-0.232	-4.0977	4.38E-05
R^2	0.01045		

Figure A-4 — Coal Steam Dataset – O&M for Less than 500-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
< 500 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	68.13	47.13	53.16	**53.41**	169	355	1,068	**1,592**
Net Total Capex - 2017 $/kW	21.01	22.83	20.67	**21.19**	169	357	1,076	**1,602**
Net Total O&M and Capex - 2017 $/kW	89.14	69.91	73.93	**74.65**	169	355	1,068	**1,592**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

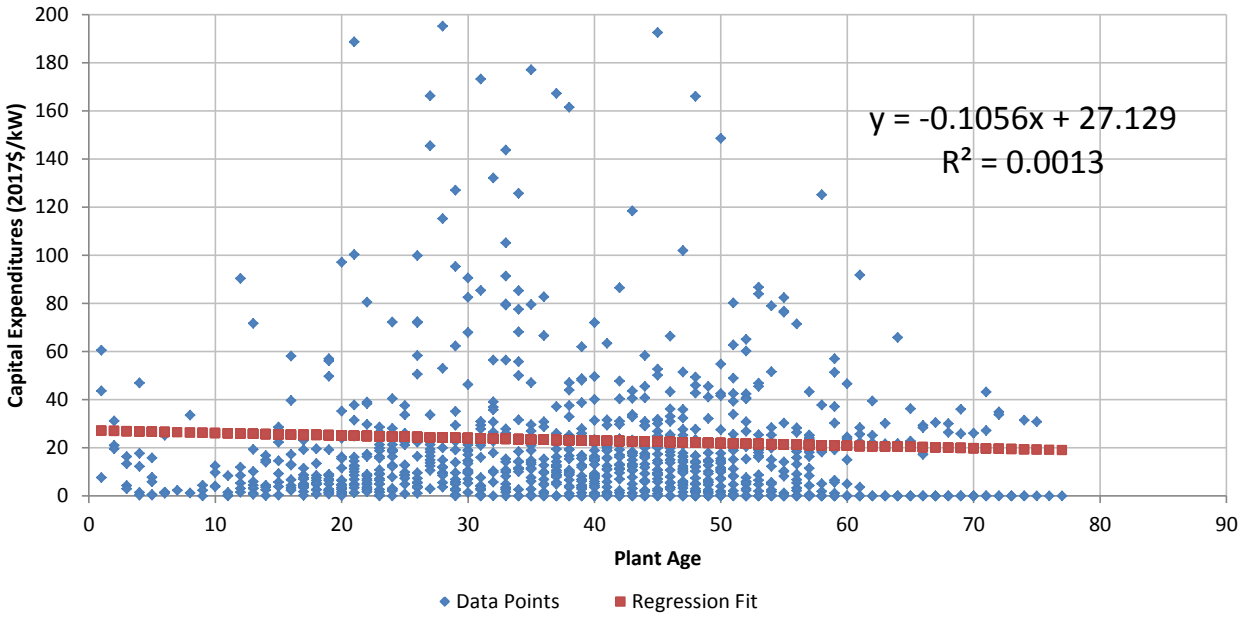
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.26, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table A-5 — Regression Statistics – Coal CAPEX 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	986		
Simple Average ($/kW)	23.021		
Intercept	27.129	6.8576	1.24E-11
Slope	-0.106	-1.1195	2.63E-01
R^2	0.00127		

Figure A-5 — Coal Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

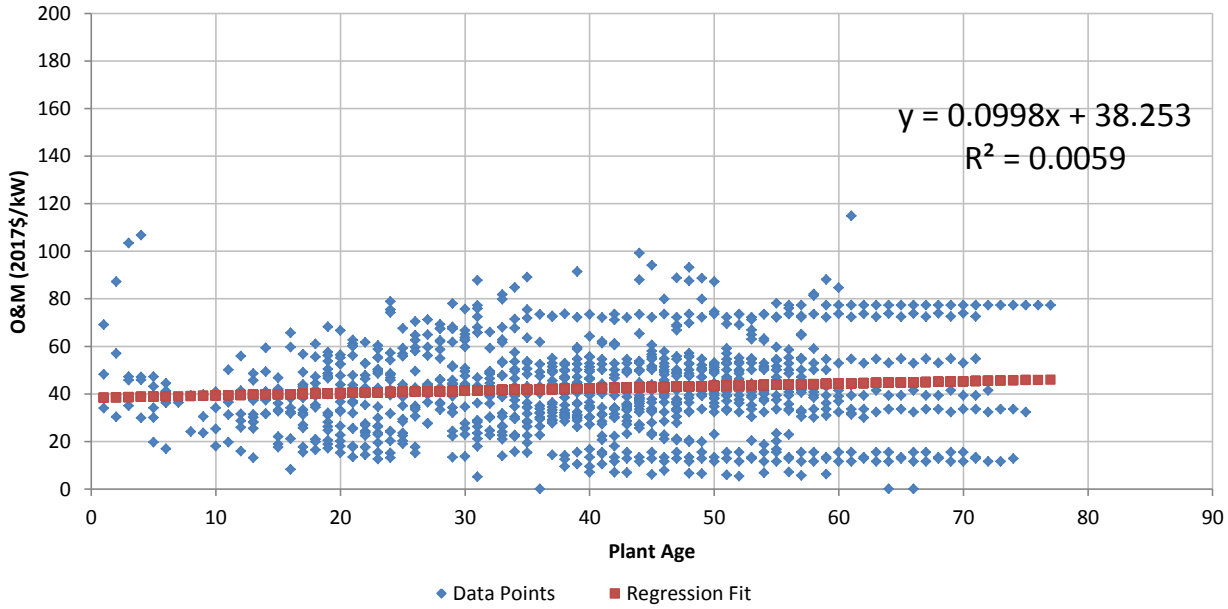
The results of the linear regression analysis of O&M spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual spending in 2017 $/kW-year = 38.253 + (0.100 × age)

Table A-6 — Regression Statistics – Coal O&M 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	1,026		
Simple Average ($/kW)	42.223		
Intercept	38.253	22.0915	9.54E-89
Slope	0.100	2.4710	1.36E-02
R^2	0.00593		

Figure A-6 — Coal Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
500 MW - 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	38.15	42.09	43.40	**42.22**	138	369	519	**1,026**
Net Total Capex - 2017 $/kW	12.27	32.63	18.71	**23.02**	138	369	479	**986**
Net Total O&M and Capex - 2017 $/kW	50.41	74.72	60.65	**64.49**	138	369	479	**986**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

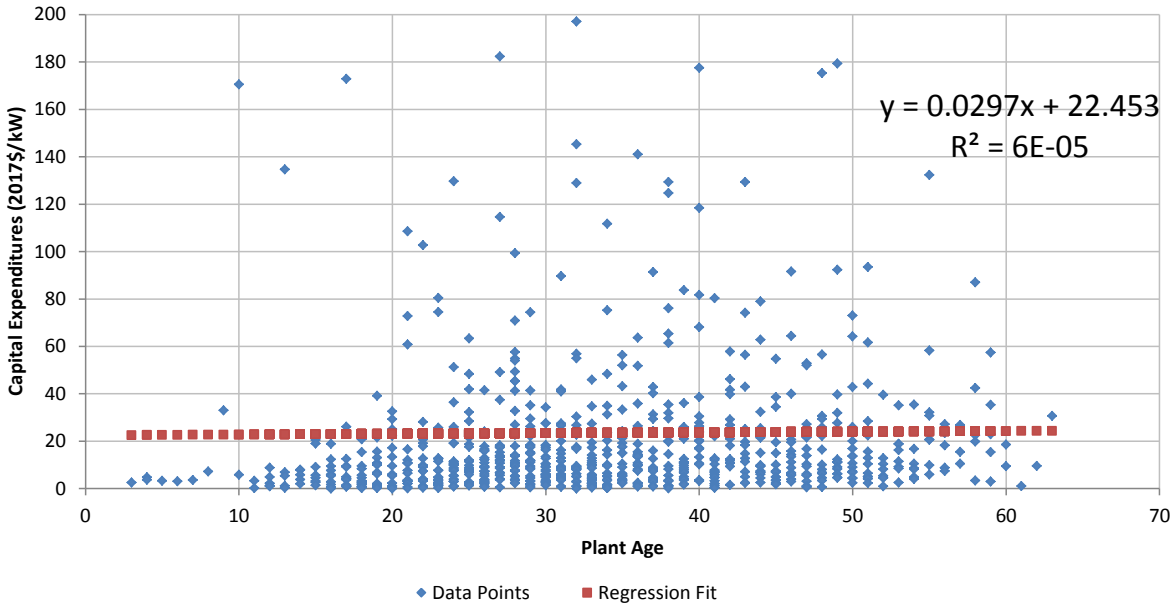
CAPITAL EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.83, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table A-7 — Regression Statistics – Coal CAPEX 1,000 MW to 2,000 MW

		t statistic	***p-value***
Observations	814		
Simple Average ($/kW)	23.448		
Intercept	22.453	4.6325	4.21E-06
Slope	0.030	0.2174	8.28E-01
R^2	0.00006		

Figure A-7 — Coal Steam Dataset – CAPEX for 1,000-MW to 2,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

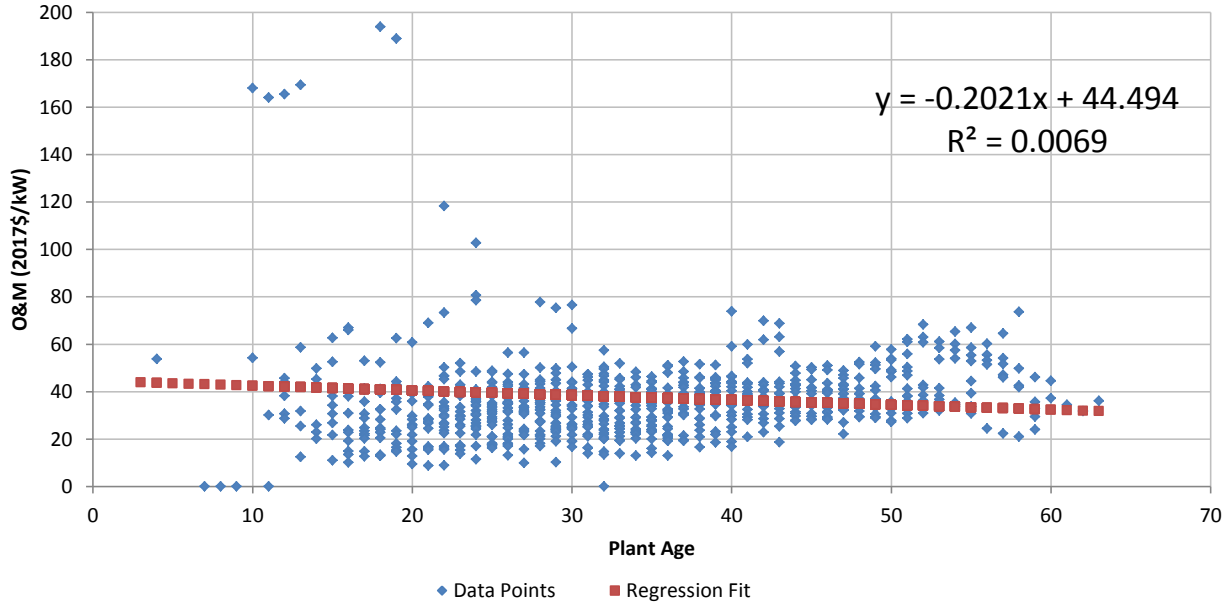
The results of the regression analysis of O&M spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual spending in 2017 $/kW-year = 44.494 + (-0.202 × age)

Table A-8 — Regression Statistics – Coal O&M 1,000 MW to 2,000 MW

		t statistic	*p-value*
Observations	813		
Simple Average ($/kW)	37.722		
Intercept	44.494	14.7620	7.42E-44
Slope	-0.202	-2.3785	1.76E-02
R^2	0.00693		

Figure A-8 — Coal Steam Dataset – O&M for 1,000-MW to 2,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
1000 MW - 2000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	53.51	32.80	40.62	**37.72**	107	478	228	**813**
Net Total Capex - 2017 $/kW	22.56	23.31	24.16	**23.45**	108	478	228	**814**
Net Total O&M and Capex - 2017 $/kW	76.28	56.11	64.78	**61.20**	107	478	228	**813**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

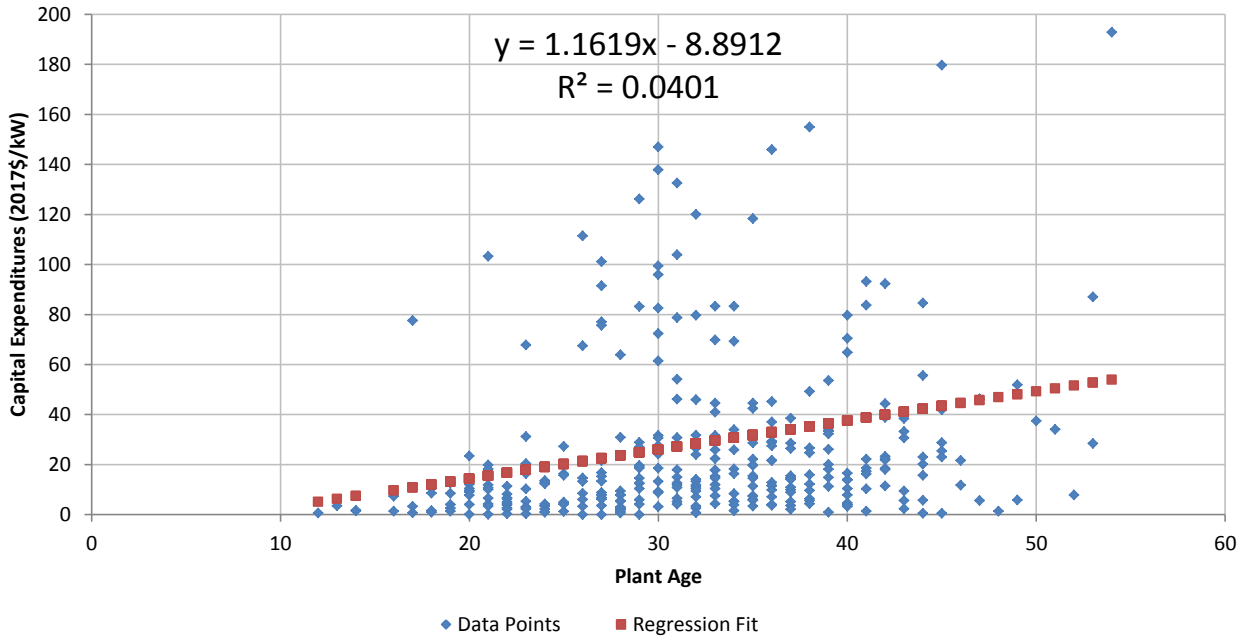
CAPITAL EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the linear regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

Table A-9 — Regression Statistics – Coal CAPEX > 2,000 MW

		t statistic	*p-value*
Observations	322		
Simple Average ($/kW)	28.303		
Intercept	-8.891	-0.8468	3.98E-01
Slope	1.162	3.6556	3.00E-04
R^2	0.04009		

Figure A-9 — Coal Steam Dataset – CAPEX for Greater than 2,000-MW Plant Size



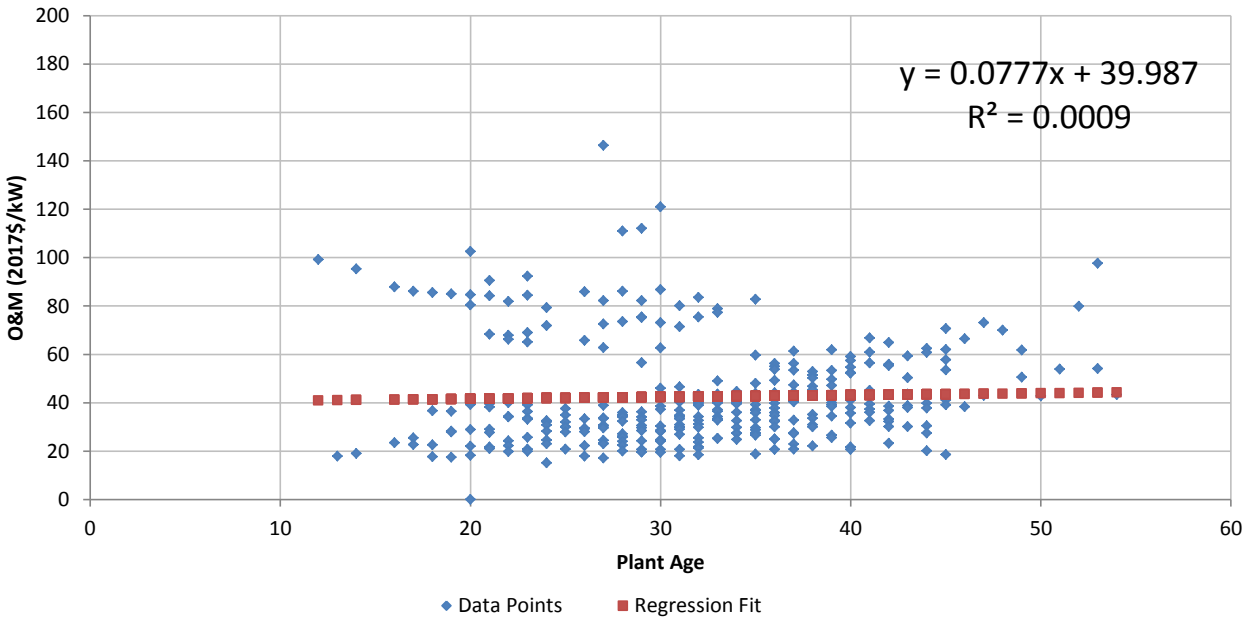
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of O&M spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.59, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table A-10 — Regression Statistics – Coal O&M > 2,000 MW

		t statistic	*p-value*
Observations	322		
Simple Average ($/kW)	42.474		
Intercept	39.987	8.3303	2.39E-15
Slope	0.078	0.5348	5.93E-01
R^2	0.00089		

Figure A-10 — Coal Steam Dataset – O&M for Greater than 2,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
> 2000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	46.55	40.91	48.04	**42.47**	26	246	50	**322**
Net Total Capex - 2017 $/kW	8.65	27.06	44.64	**28.30**	26	246	50	**322**
Net Total O&M and Capex - 2017 $/kW	55.20	67.97	92.67	**70.78**	26	246	50	**322**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

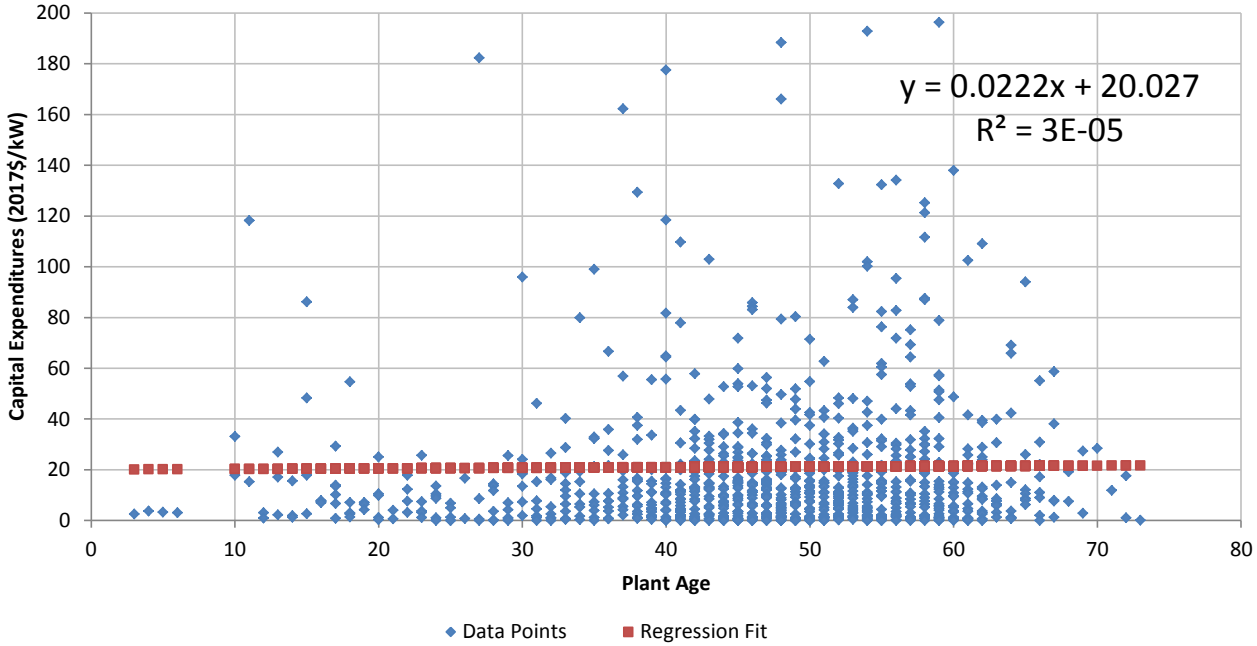
CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.87, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table A-11 — Regression Statistics – Coal CAPEX for Capacity Factor < 50%

		t statistic	*p-value*
Observations	972		
Simple Average ($/kW)	21.063		
Intercept	20.027	3.1188	1.87E-03
Slope	0.022	0.1663	8.68E-01
R^2	0.00003		

Figure A-11 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor < 50%



Note: Age coefficient in above regression equation is not statistically significant.

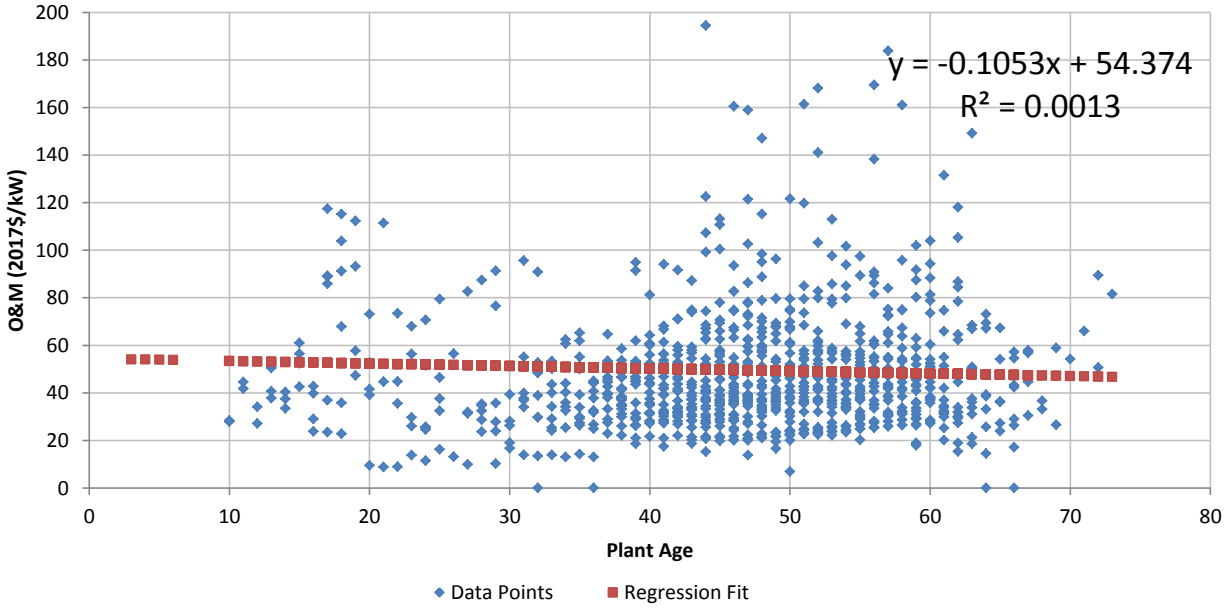
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.26, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

Table A-12 — Regression Statistics – Coal O&M for Capacity Factor < 50%

		t statistic	*p-value*
Observations	965		
Simple Average ($/kW)	49.454		
Intercept	54.374	12.0380	3.43E-31
Slope	-0.105	-1.1234	2.62E-01
R^2	0.00131		

Figure A-12 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor < 50%



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, Capacity Factors 0 - 50%								
Net Total O&M- 2017 $/kW	76.43	40.01	50.07	**49.45**	45	177	743	**965**
Net Total Capex - 2017 $/kW	19.62	23.74	20.51	**21.06**	45	179	748	**972**
Net Total O&M and Capex - 2017 $/kW	96.04	63.66	70.63	**70.54**	45	177	743	**965**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

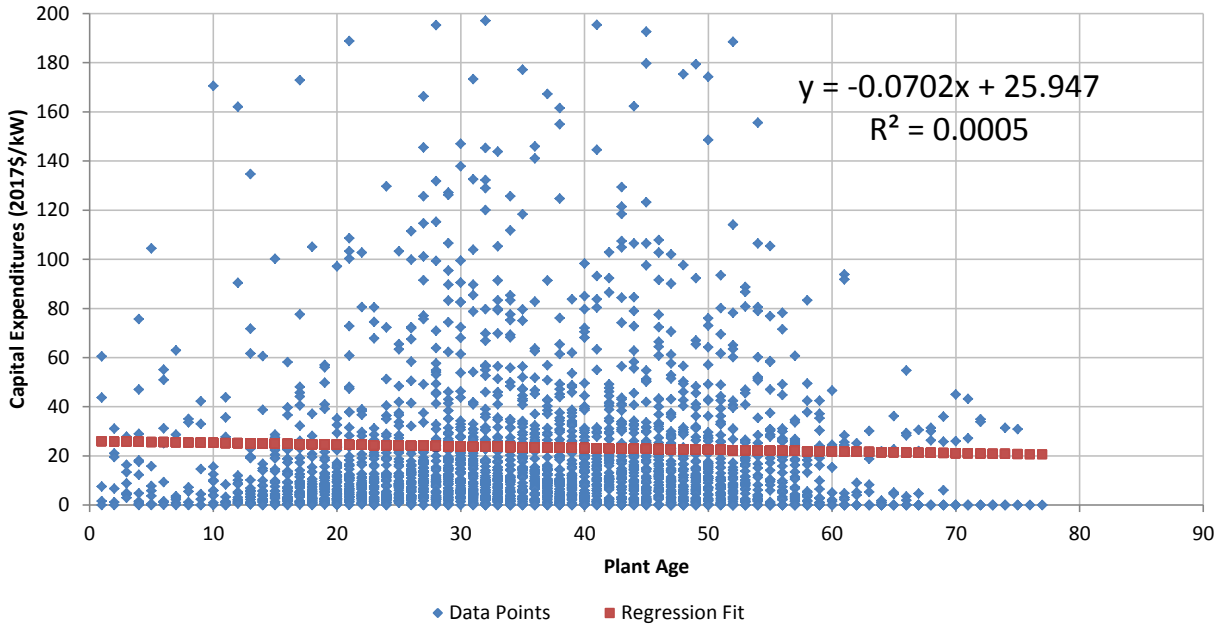
CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.25, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table A-13 — Regression Statistics – Coal CAPEX for Capacity Factor > 50%

		t statistic	*p-value*
Observations	2752		
Simple Average ($/kW)	23.389		
Intercept	25.947	10.7905	1.29E-26
Slope	-0.070	-1.1446	2.52E-01
R^2	0.00048		

Figure A-13 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor > 50%



Note: Age coefficient in above regression equation is not statistically significant.

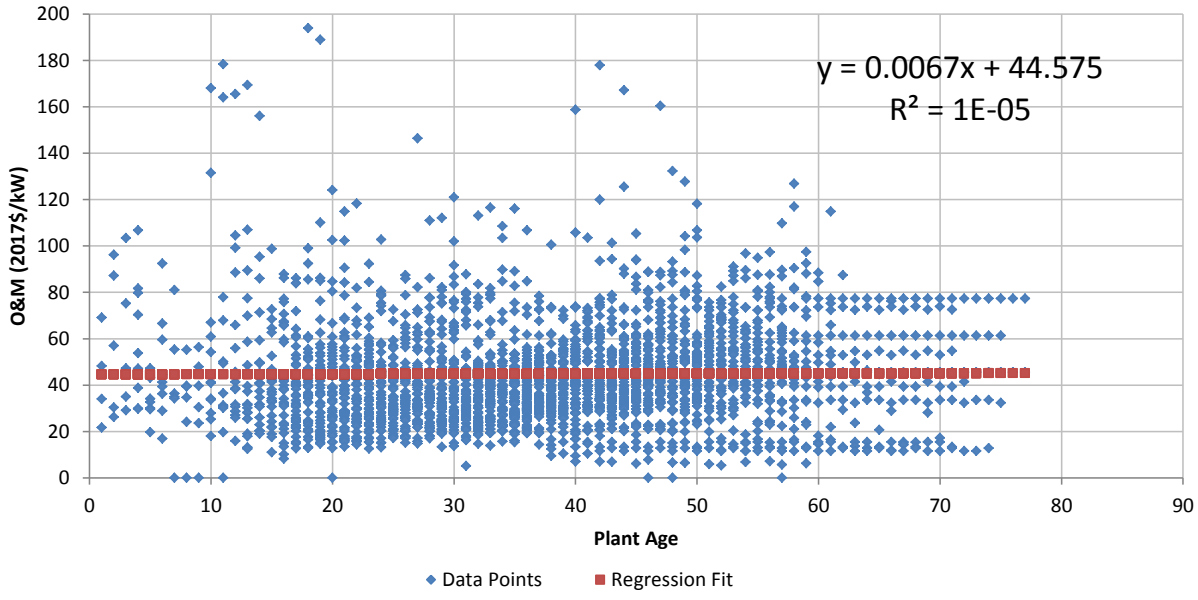
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.85, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

Table A-14 — Regression Statistics – Coal O&M for Capacity Factor > 50%

		t statistic	*p-value*
Observations	2788		
Simple Average ($/kW)	44.822		
Intercept	44.575	32.6995	8.78E-199
Slope	0.007	0.1954	8.45E-01
R^2	0.00001		

Figure A-14 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor > 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

`	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, Capacity Factors 50% - 100%								
Net Total O&M- 2017 $/kW	51.33	40.07	47.92	**44.82**	395	1,271	1,122	**2,788**
Net Total Capex - 2017 $/kW	17.73	26.55	21.75	**23.39**	396	1,271	1,085	**2,752**
Net Total O&M and Capex - 2017 $/kW	69.11	66.62	69.25	**68.01**	395	1,271	1,082	**2,748**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

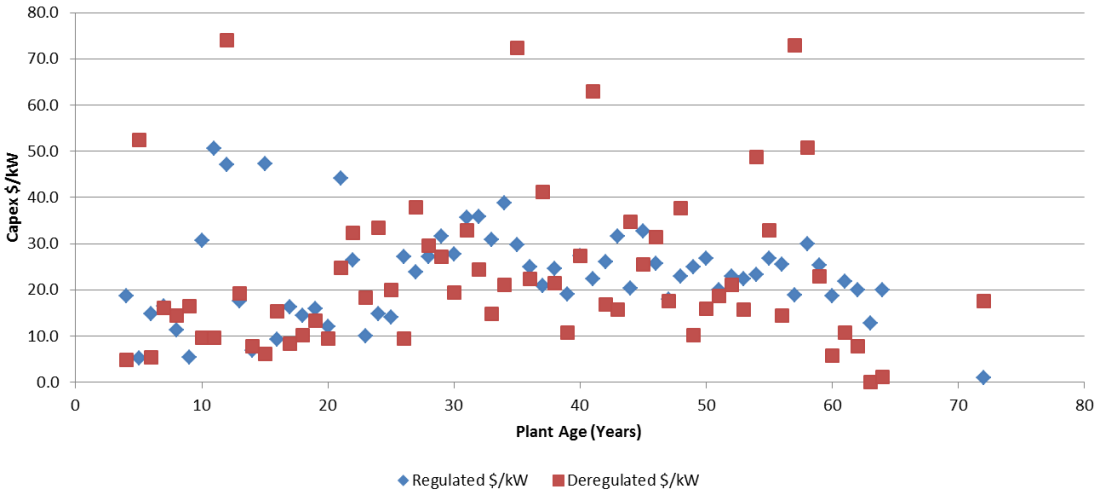
CAPITAL EXPENDITURES – REGULATED VS. DEREGULATED

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in regulated versus deregulated locations are summarized in the table below. Since the p-value for the age ("slope") and regulation/deregulation coefficients are much greater than 0.05, age and regulatory status are not statistically significant predictors of CAPEX spending.

Table A-15 — Regression Statistics – Coal CAPEX for Regulated/Deregulated

	Coefficients	Standard Error	t Stat	P-Value
Intercept	23.22826383	2.9645403	7.835367875	6.36821E-15
Age	0.097334249	0.064355791	1.512439626	0.130523796
Reg./Dereg. (1/0)	-2.479225741	2.148990587	-1.153669893	0.248724297

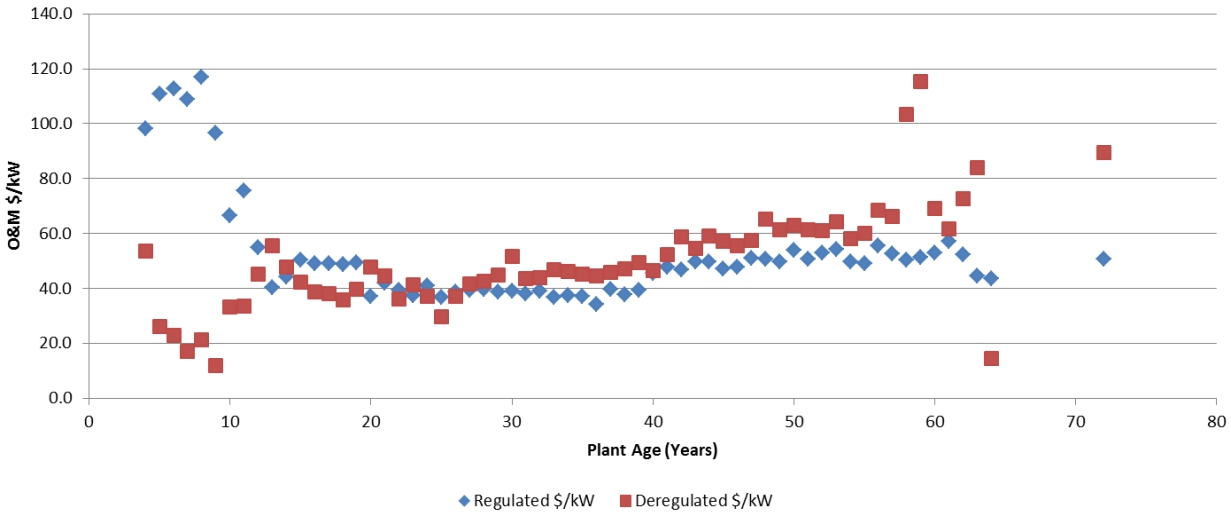
Figure A-15 — Coal Steam Dataset – CAPEX for Regulated/Deregulated



OPERATIONS & MAINTENANCE EXPENDITURES – REGULATED VS. DEREGULATED

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and regulated/deregulated coefficients are much less than 0.05 (i.e., statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. After year 20, a visual inspection of the data points indicates higher O&M spending in deregulated states compared with regulated states (Figure A-16). This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending is not apparent at this level of detail.

Figure A-16 — Coal Steam Dataset – O&M for Regulated vs. Deregulated



CAPITAL EXPENDITURES – FGD VS. NO FGD

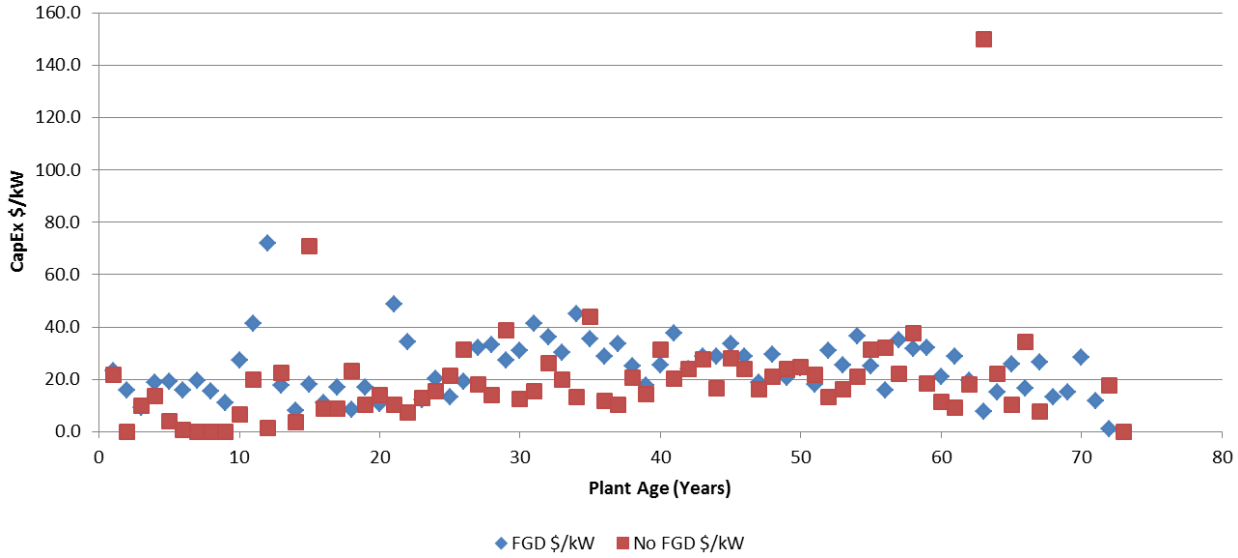
The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) with and without FGD are summarized in the table below. The p-value for the age ("slope") coefficient is slightly greater than 0.05 (nearly statistically significant) while the p-value for the FGD/no-FGD coefficient is much less than 0.05 (statistically significant). A visual inspection of the difference between the FGD and no-FGD data points in Figure A-17 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending may be represented by the following regression equation:

Annual CAPEX spending in 2017 $/kW-year = 16.53 + (0.126 × age) + (5.68 × FGD)
Where FGD = 1 if plant has FGD; zero otherwise

Table A-16 — Regression Statistics – Coal CAPEX for FGD/No FGD

	Coefficients	Standard Error	t Stat	P-Value
Intercept	16.52586075	3.06139723	5.39814323	7.2399E-08
Age	0.126266024	0.065143952	1.93826166	0.05268181
FGD/No FGD (1/0)	5.6788887	1.913609818	2.96763146	0.00302395

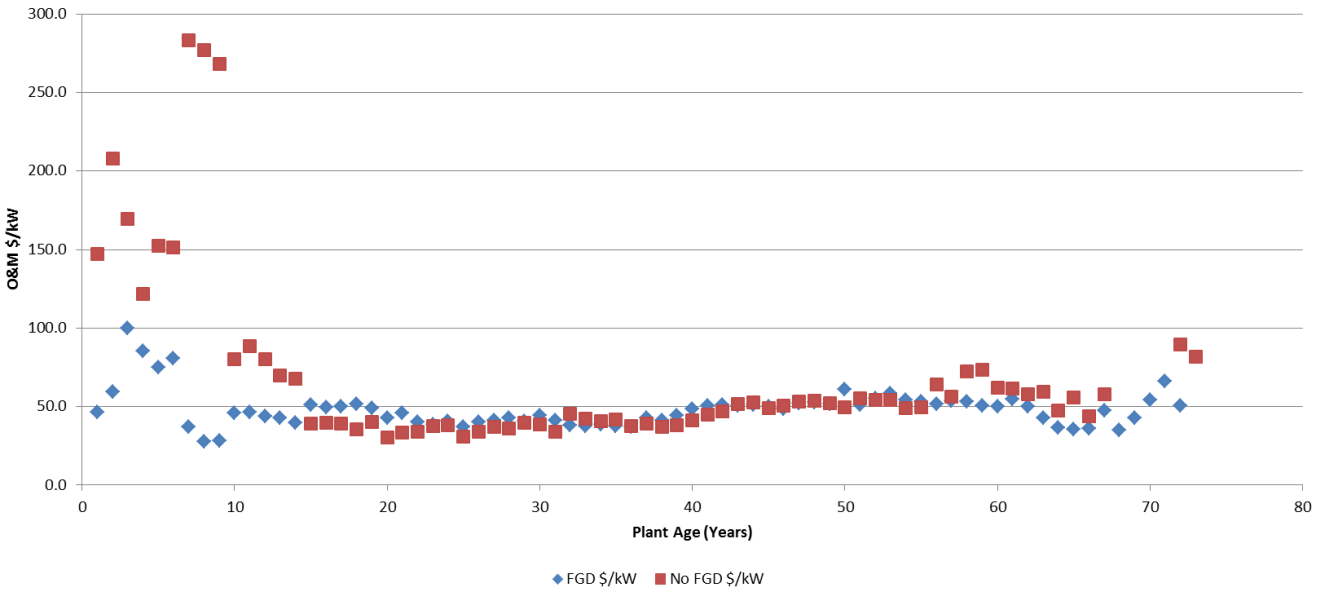
Figure A-17 — Coal Steam Dataset – CAPEX for FGD/No FGD



OPERATIONS & MAINTENANCE EXPENDITURES – FGD VS. NO FGD

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and FGD/no-FGD coefficients are much less than 0.05 (i.e., statistically significant). However, outliers before year 15 may tend to distort the regression analysis. A visual inspection of the difference between the FGD and no-FGD data points in Figure A-18 shows a similarity in O&M spending amounts across all ages after year 15. The differences in annual coal plant spending due to having FGD is more significant in the CAPEX accounts, as shown in the previous subsection, rather than the O&M accounts.

Figure A-18 — Coal Steam Dataset – O&M for FGD vs. No FGD



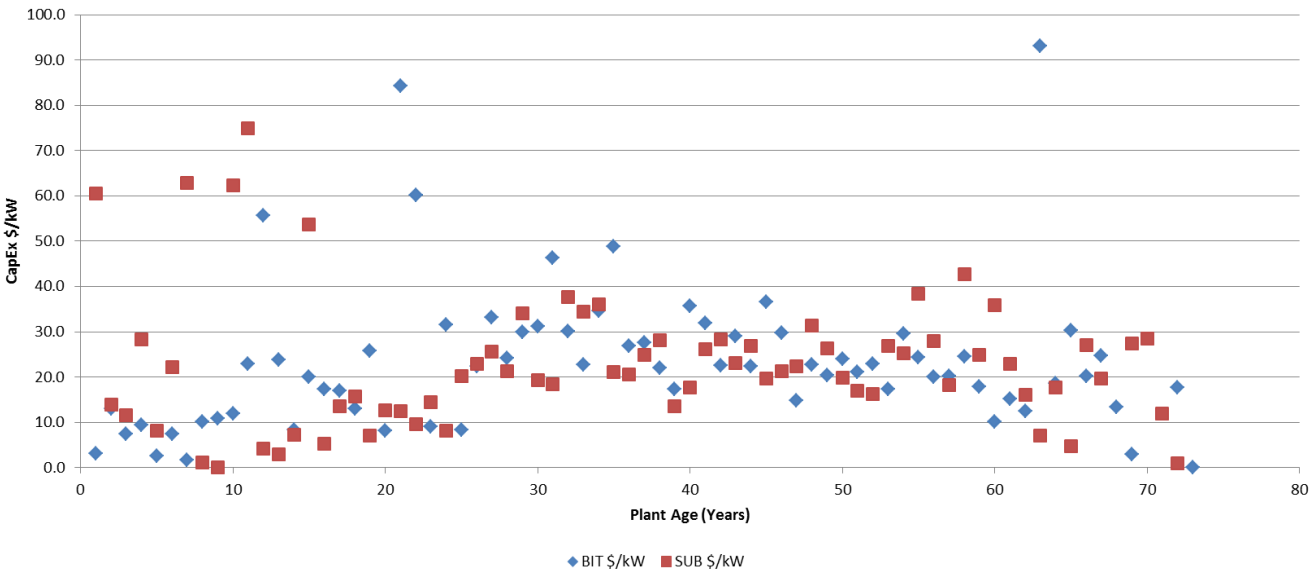
CAPITAL EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in bituminous versus subbituminous coal types are summarized in the table below. The p-value for the age ("slope") coefficient is much greater than 0.05 (not statistically significant), while the p-value for the bituminous/subbituminous coefficient is much less than 0.05 (statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-19 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

Table A-17 — Regression Statistics – Coal CAPEX for Bituminous/Subbituminous

	Coefficients	Standard Error	t Stat	P-Value
Intercept	15.39252046	2.257695952	6.817800442	1.08205E-11
Age	-0.00350504	0.054578287	-0.064220408	0.948798346
Bit./Sub. (1/0)	10.93481186	1.525466511	7.168175624	9.20398E-13

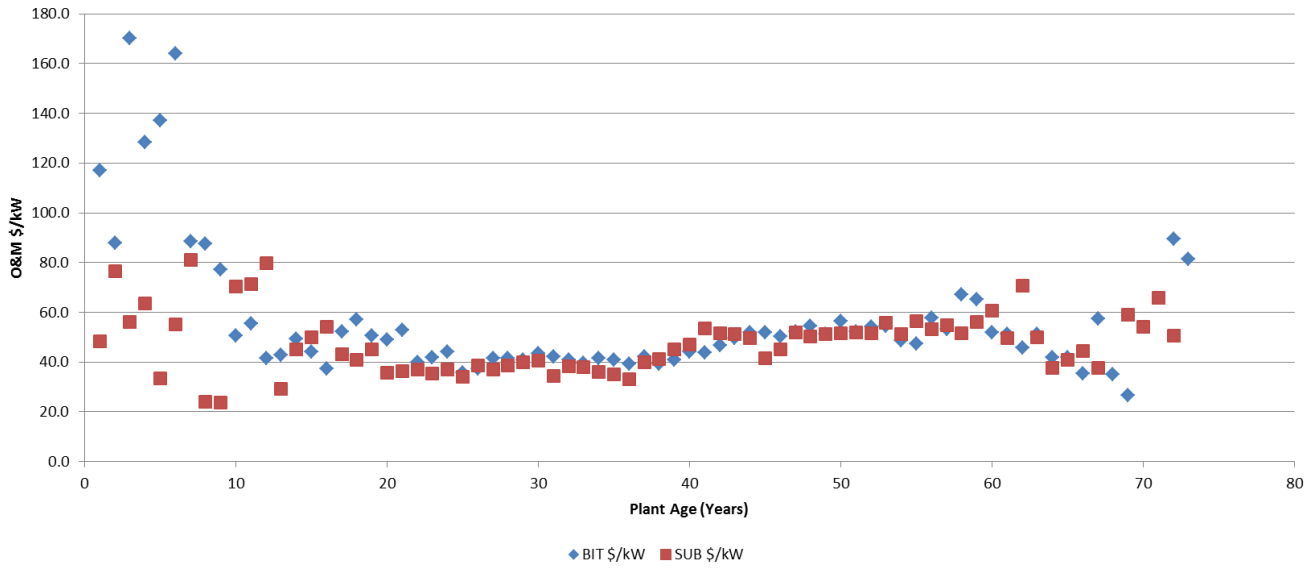
Figure A-19 — Coal Steam Dataset – CAPEX for Bituminous/Subbituminous



OPERATIONS & MAINTENANCE EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and bituminous/subbituminous coefficients are much less than 0.05 (statistically significant). However, as with CAPEX spending, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-20 shows a similarity in O&M spending amounts across all ages. Therefore, average O&M spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

Figure A-20 — Coal Steam Dataset – O&M for Bituminous vs. Subbituminous



EFFECT OF PLANT CAPACITY FACTOR

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time. Figure A-21 and Figure A-22 indicate real annual increases in CAPEX and O&M spending for the coal steam plants in constant 2017 $/MWh versus plant age, with linear regression results as follows:

- Annual CAPEX in 2017 $/MWh = 3.27 + (0.0426 × age)
- Annual O&M in 2017 $/MWh = 5.44 + (0.133 × age)

Figure A-21 — CAPEX vs. Age for All MW Coal Plants (2017 $/MWh)

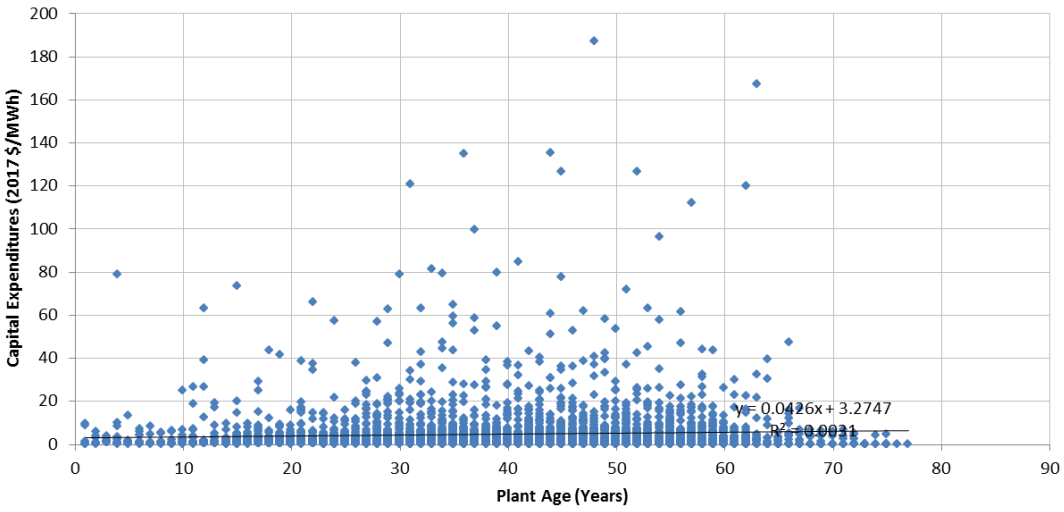
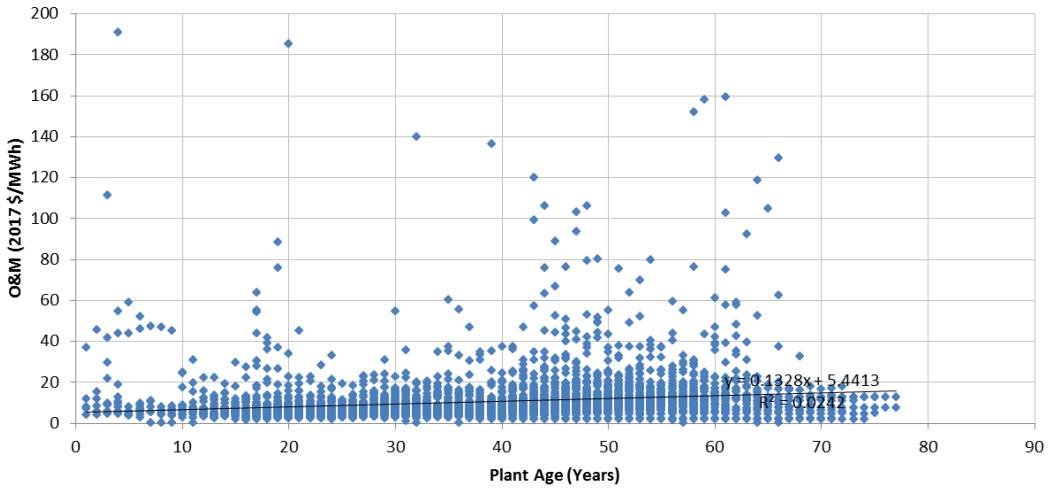


Figure A-22 — O&M vs. Age for All Coal Plants (2017 $/MWh)



In both of the above regression results, the age coefficient was found to be statistically significant. This was determined to be a result of the average decline in capacity factors for the coal steam plants, as shown in Figure A-23. A similar decline also occurred with the gas/oil steam plants, as shown in Figure A-24.

Figure A-23 — Capacity Factor vs. Age for All Coal Plants

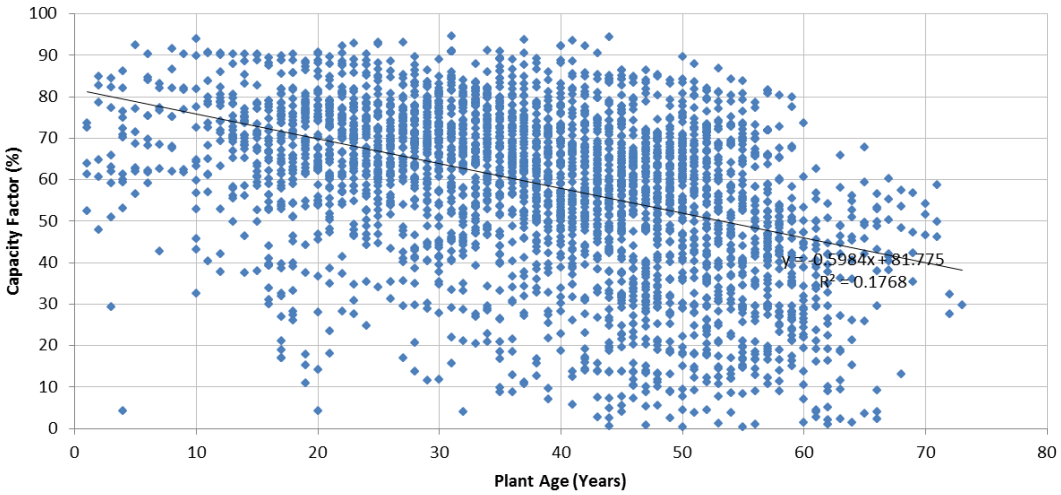
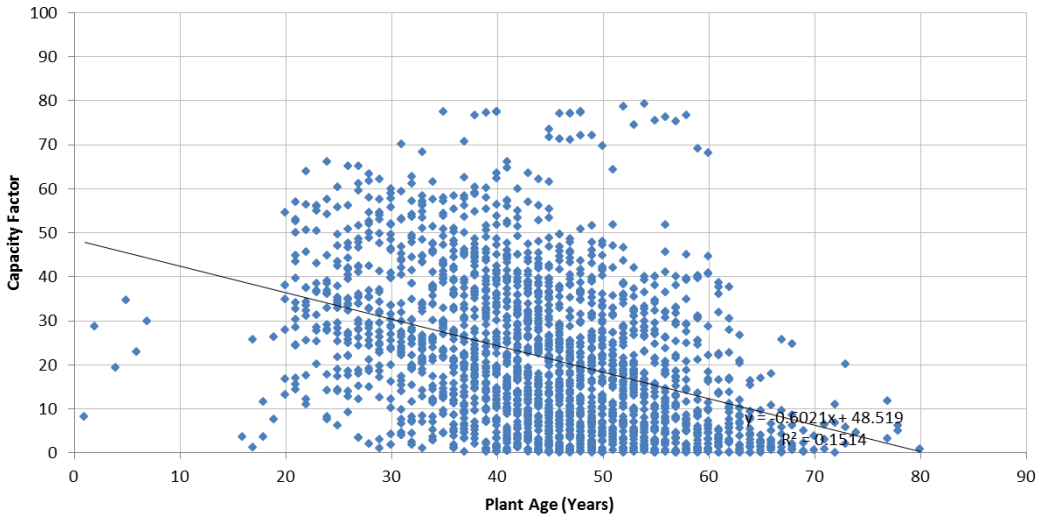


Figure A-24 — Capacity Factor vs. Age for All Gas/Oil Steam Plants





Appendix B. Regression Analysis – Gas/Oil Steam

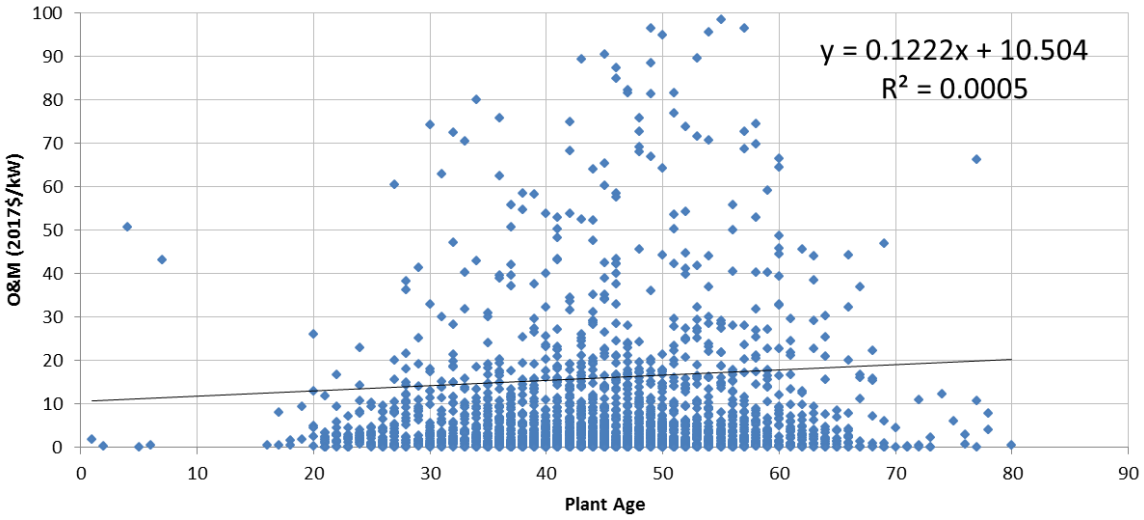
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.29, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table B-1 — Regression Statistics – Gas/Oil Steam CAPEX for All MW

		t statistic	*p-value*
Observations	2,226		
Simple Average ($/kW)	15.955		
Intercept	10.504	1.9741	4.85E-02
Slope	0.122	1.0551	2.91E-01
R^2	0.00050		

Figure B-1 — Gas/Oil Steam Dataset – CAPEX for All Plant MW Sizes



Note: Age coefficient in above regression equation is not statistically significant.

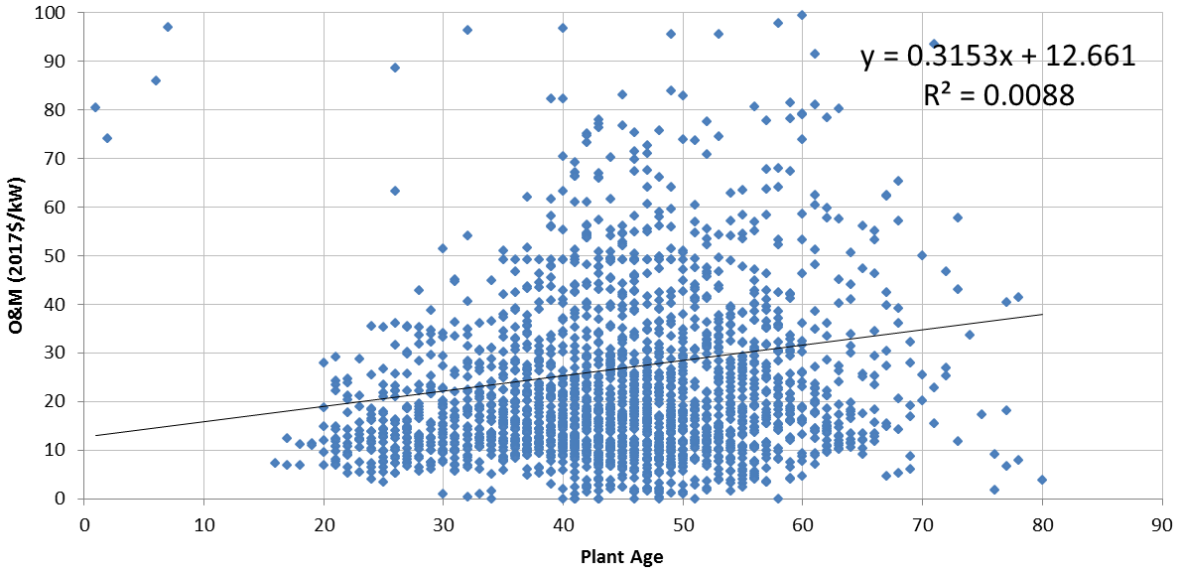
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

Table B-2 — Regression Statistics – Gas/Oil Steam O&M for All MW

		t statistic	*p-value*
Observations	2,224		
Simple Average ($/kW)	26.723		
Intercept	12.661	3.8863	1.05E-04
Slope	0.315	4.4455	9.20E-06
R^2	0.00882		

Figure B-2 — Gas/Oil Steam Dataset – O&M for All Plant MW Sizes



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	39.39	23.48	28.18	**26.72**	19	733	1,472	**2,224**
Net Total Capex - 2017 $/kW	8.91	14.18	16.93	**15.96**	19	733	1,474	**2,226**
Net Total O&M and Capex - 2017 $/kW	48.30	37.53	45.10	**42.63**	19	731	1,470	**2,220**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

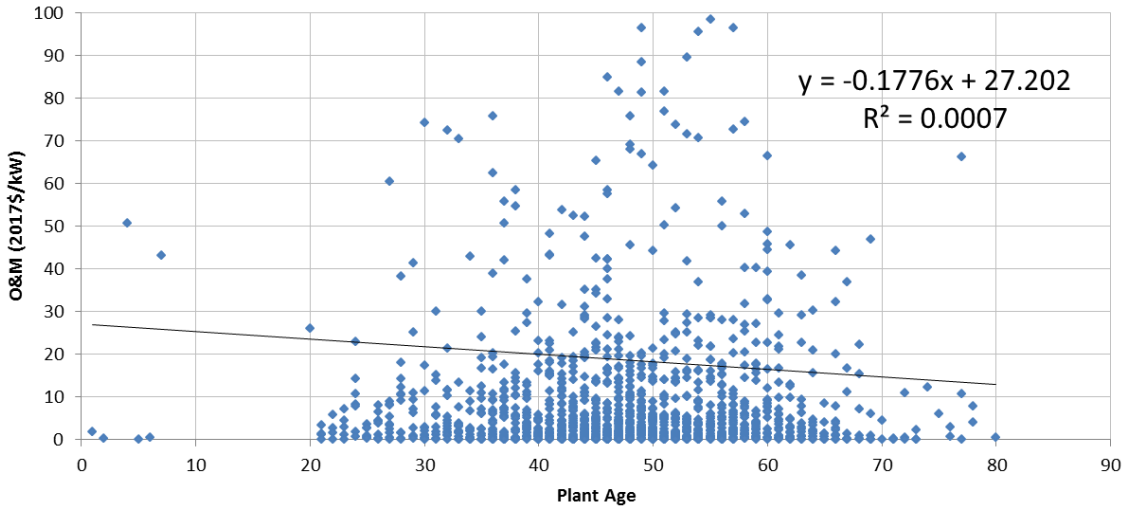
CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.32, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table B-3 — Regression Statistics – Gas/Oil Steam CAPEX < 500 MW

		t statistic	*p-value*
Observations	1382		
Simple Average ($/kW)	18.392		
Intercept	27.202	3.1265	1.81E-03
Slope	-0.178	-0.9867	3.24E-01
R^2	0.00071		

Figure B-3 — Gas/Oil Steam Dataset – CAPEX for Less than 500-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

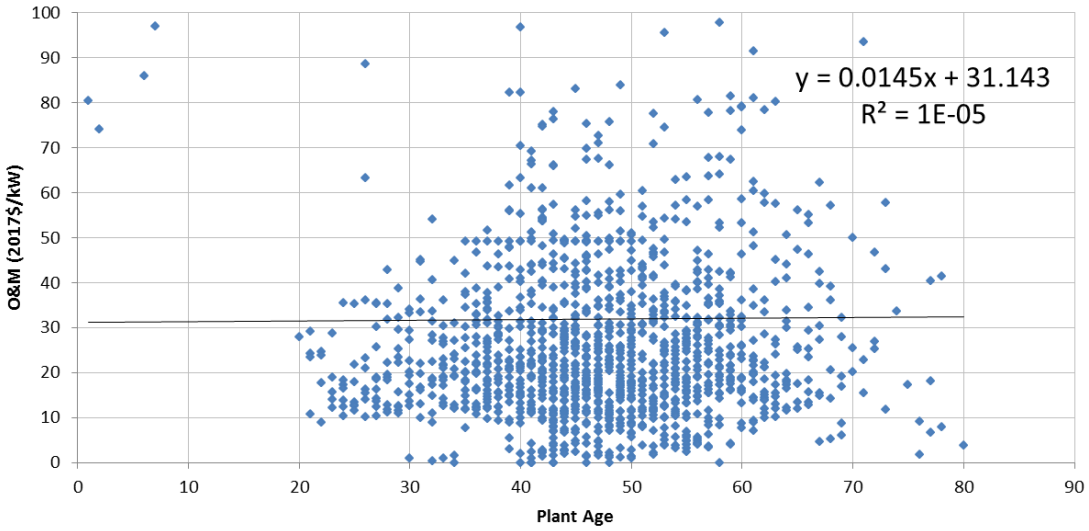
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of O&M spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.90, which is greater than 0.05, age is not a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table B-4 — Regression Statistics – Gas/Oil Steam O&M < 500 MW

		t statistic	*p-value*
Observations	1,381		
Simple Average ($/kW)	31.827		
Intercept	31.143	5.7925	8.58E-09
Slope	0.015	0.1305	8.96E-01
R^2	0.00001		

Figure B-4 — Gas/Oil Steam Dataset – O&M for Less than 500-MW Plant Size



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
< 500 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	88.54	33.36	30.98	**31.83**	7	324	1,050	**1,381**
Net Total Capex - 2017 $/kW	17.44	22.13	17.82	**18.83**	7	324	1,051	**1,382**
Net Total O&M and Capex - 2017 $/kW	105.98	55.32	48.78	**50.60**	7	322	1,048	**1,377**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

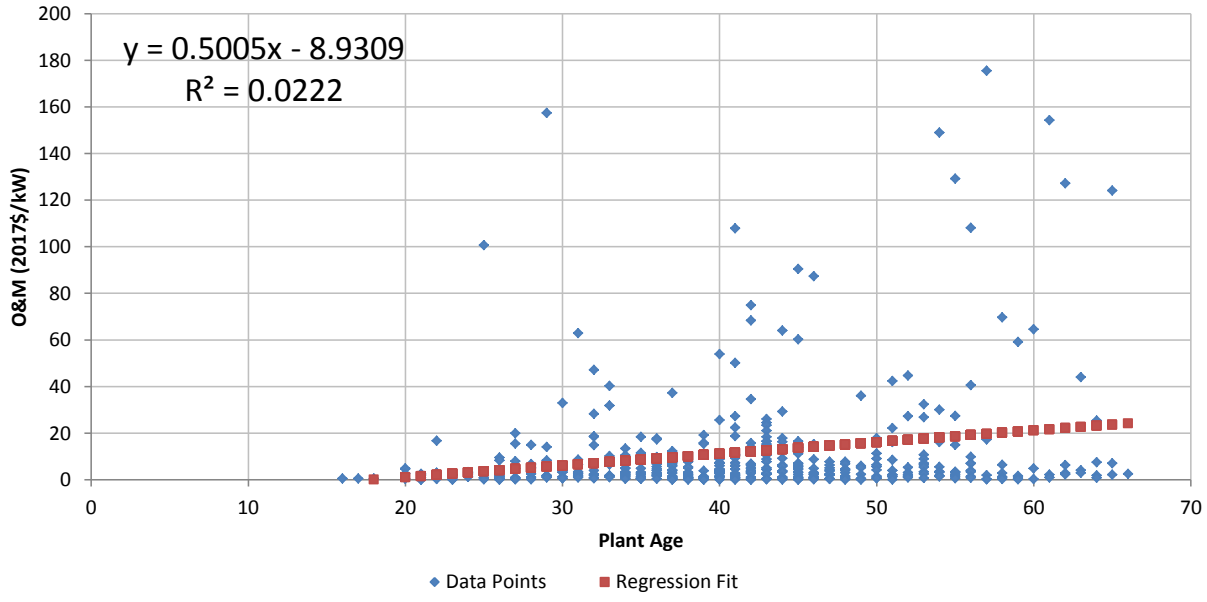
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

Table B-5 — Regression Statistics – Gas/Oil Steam CAPEX 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	489		
Simple Average ($/kW)	11.570		
Intercept	-8.988	-1.4118	1.59E-01
Slope	0.501	3.3322	9.27E-04
R^2	0.02229		

Figure B-5 — Gas/Oil Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



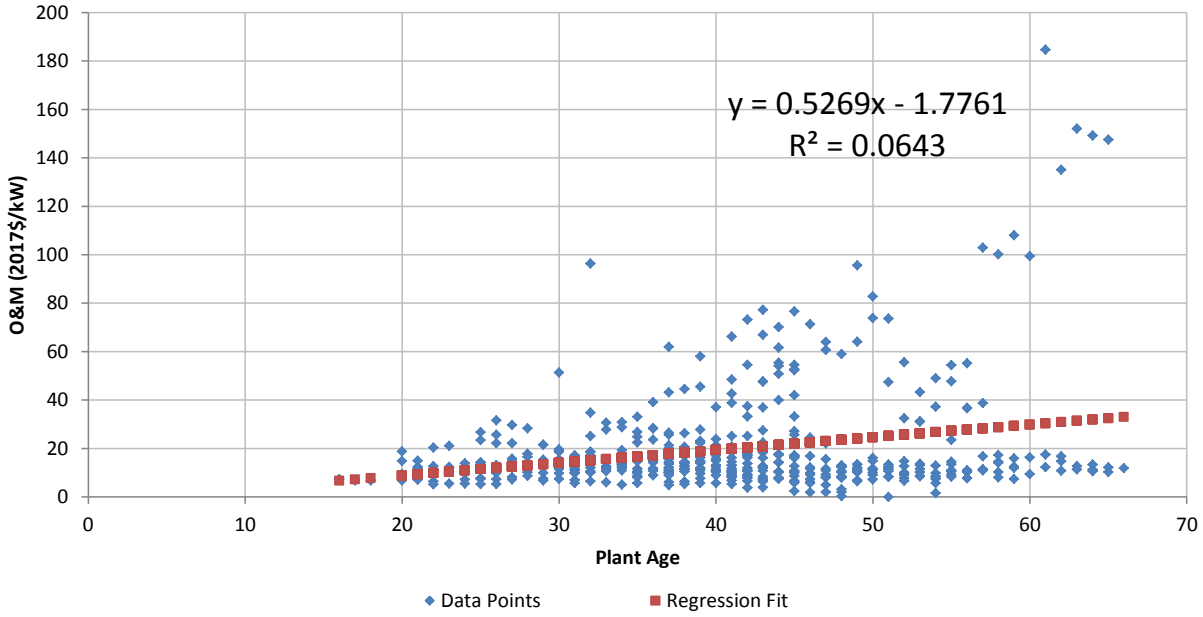
OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending. However, the regression analysis shows the intercept value (i.e., the O&M cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited data causes the regression analysis to be distorted.

Table B-6 — Regression Statistics – Gas/Oil Steam O&M 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	488		
Simple Average ($/kW)	19.823		
Intercept	-1.776	-0.4606	6.45E-01
Slope	0.527	5.7810	1.33E-08
R^2	0.06434		

Figure B-6 — Gas/Oil Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
500 MW - 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	10.10	15.82	23.61	**19.82**	7	225	256	**488**
Net Total Capex - 2017 $/kW	1.94	6.32	16.43	**11.57**	7	225	257	**489**
Net Total O&M and Capex - 2017 $/kW	12.04	22.14	40.07	**31.40**	7	225	256	**488**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

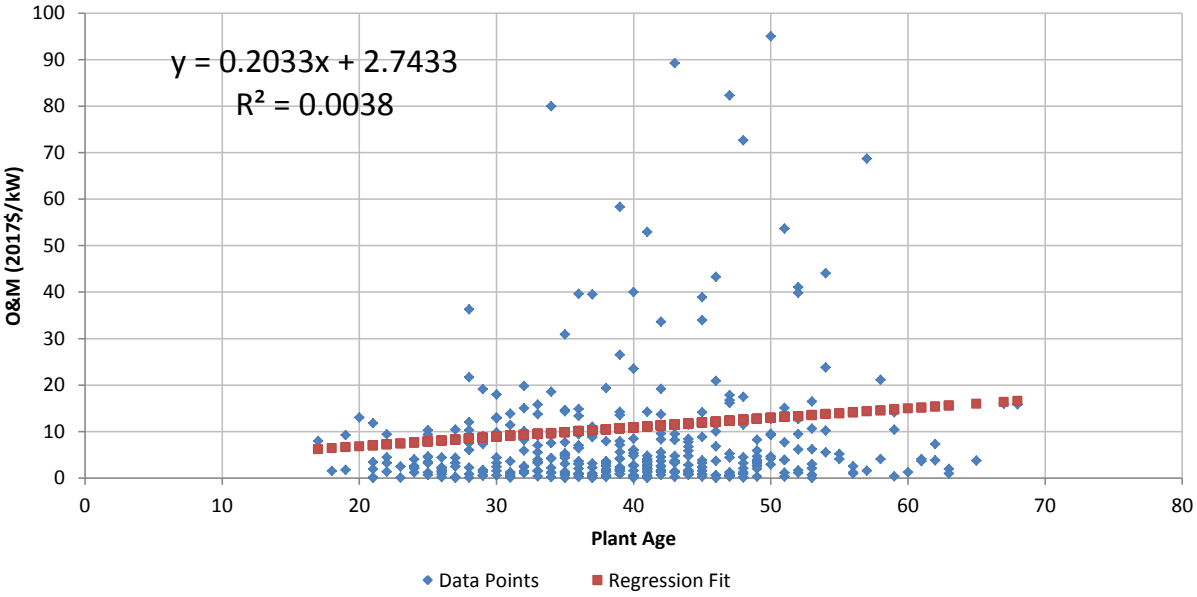
CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.24, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table B-7 — Regression Statistics – Gas/Oil Steam CAPEX > 1,000 MW

		t statistic	*p-value*
Observations	355		
Simple Average ($/kW)	10.815		
Intercept	2.743	0.3846	7.01E-01
Slope	0.203	1.1660	2.44E-01
R^2	0.00384		

Figure B-7 — Gas/Oil Steam Dataset – CAPEX for Greater than 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

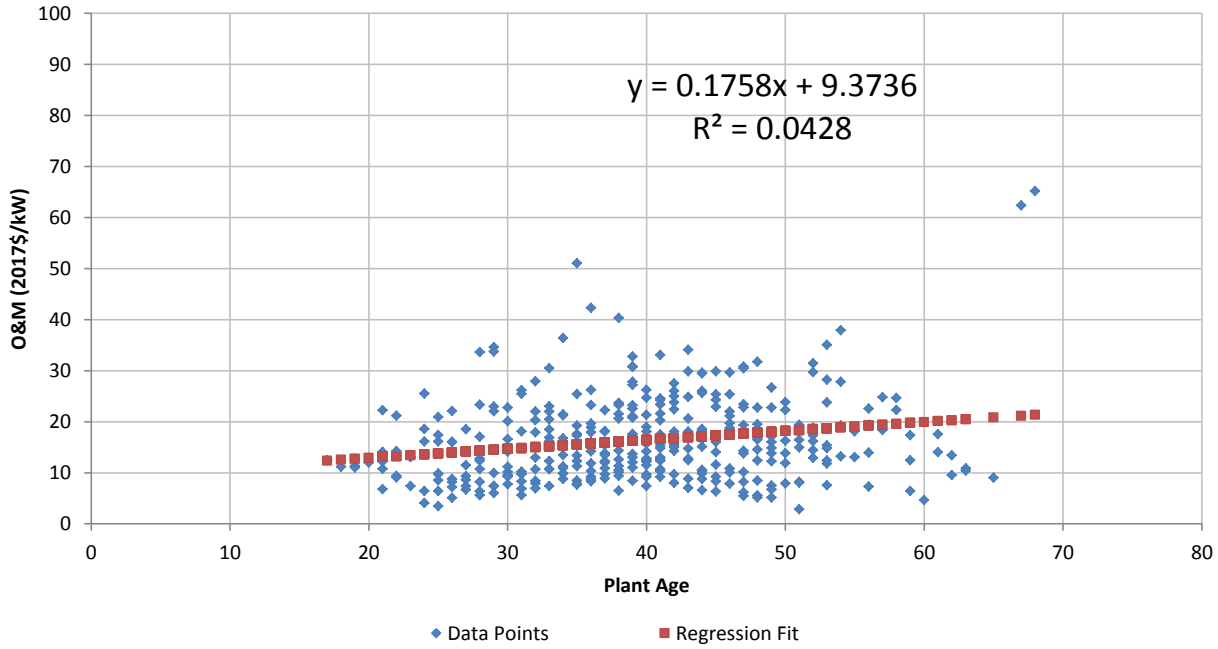
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

Table B-8 — Regression Statistics – Gas/Oil Steam O&M > 1,000 MW

		t statistic	*p-value*
Observations	355		
Simple Average ($/kW)	16.353		
Intercept	9.374	5.1812	3.71E-07
Slope	0.176	3.9752	8.53E-05
R^2	0.04285		

Figure B-8 — Gas/Oil Steam Dataset – O&M for Greater than 1,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
> 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	11.59	15.44	17.50	**16.35**	5	184	166	**355**
Net Total Capex - 2017 $/kW	6.70	9.78	12.09	**10.82**	5	184	166	**355**
Net Total O&M and Capex - 2017 $/kW	18.29	25.22	29.60	**27.17**	5	184	166	**355**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.



Appendix C. Regression Analysis – Gas/Oil Combined Cycle

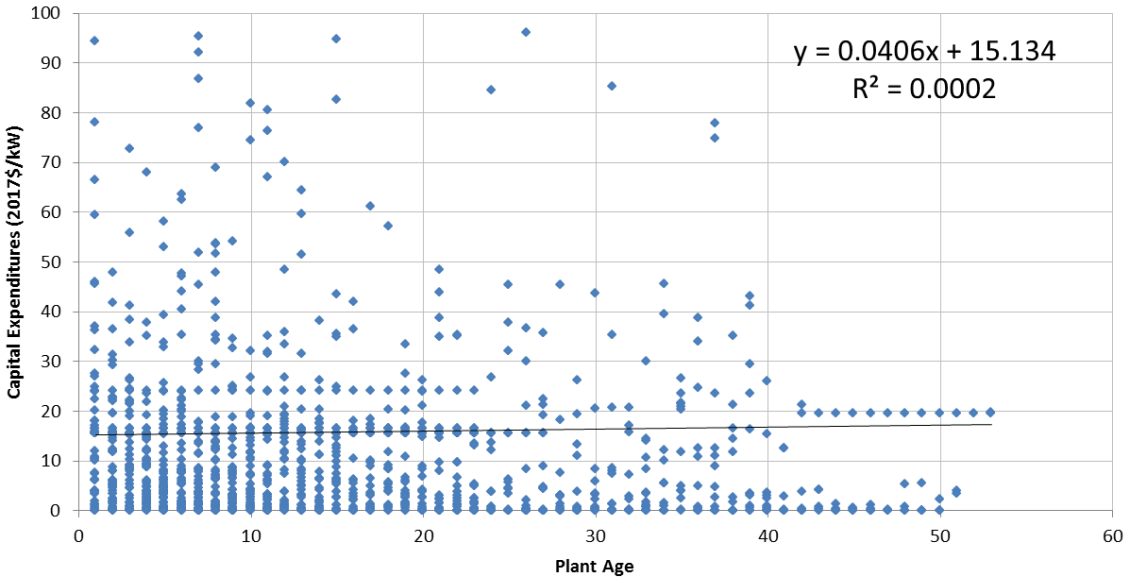
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.63, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-1 — Regression Statistics – CC CAPEX for All MW

		t statistic	*p-value*
Observations	1,368		
Simple Average ($/kW)	15.765		
Intercept	15.134	9.2176	1.11E-19
Slope	0.041	0.4853	6.28E-01
R^2	0.00017		

Figure C-1 — Gas/Oil CC Dataset – CAPEX for All Plant MW Sizes



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

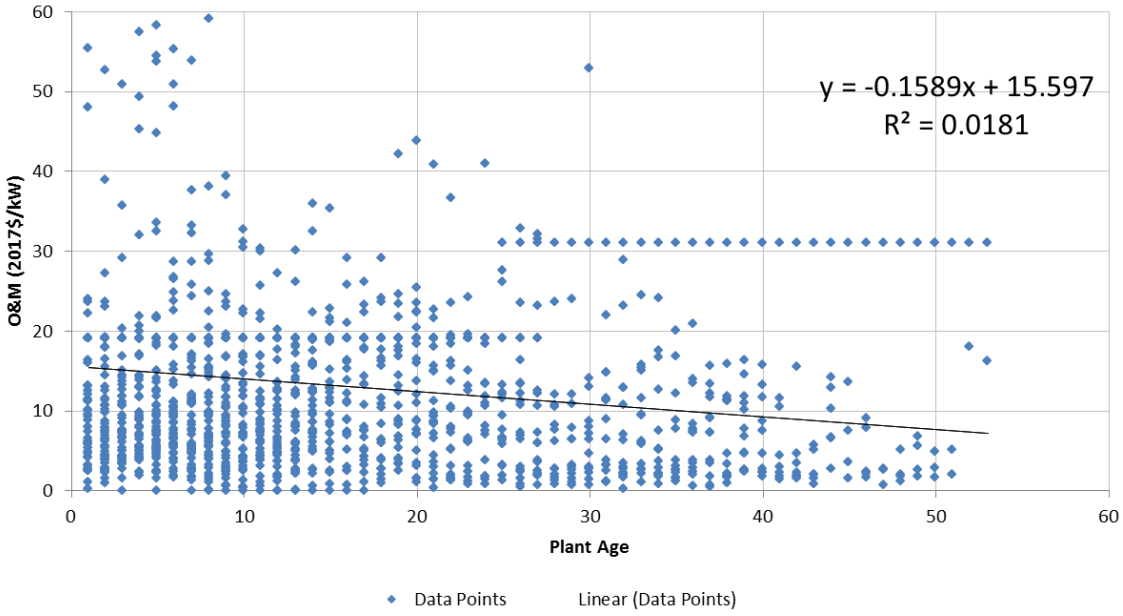
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is much lower than 0.05, the dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table C-2 — Regression Statistics – CC O&M for All MW

		t statistic	*p-value*
Observations	1,388		
Simple Average ($/kW)	13.080		
Intercept	15.597	24.8961	2.19E-113
Slope	-0.159	-5.0573	4.82E-07
R^2	0.01812		

Figure C-2 — Gas/Oil CC Dataset – O&M for All Plant MW Sizes



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	14.16	10.56	10.26	**13.08**	978	344	66	**1,388**
Net Total Capex - 2017 $/kW	15.45	16.37	17.56	**15.76**	979	326	63	**1,368**
Net Total O&M and Capex - 2017 $/kW	29.64	27.24	28.19	**29.00**	976	326	63	**1,365**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

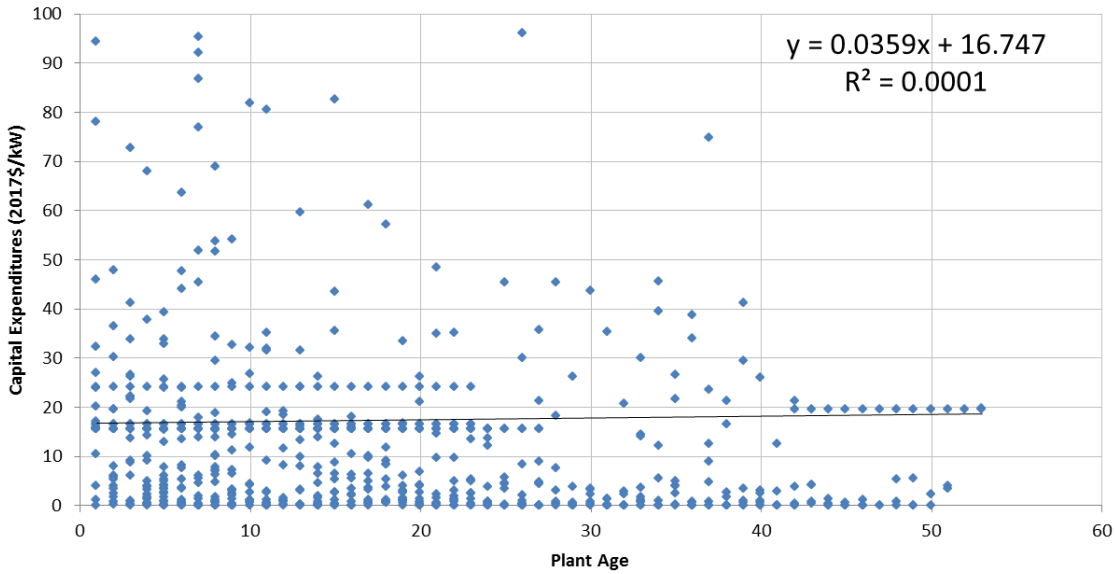
CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants under 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.76, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-3 — Regression Statistics – CC CAPEX < 500 MW

		t statistic	*p-value*
Observations	765		
Simple Average ($/kW)	17.378		
Intercept	16.747	6.4870	1.57E-10
Slope	0.036	0.3007	7.64E-01
R^2	0.00012		

Figure C-3 — Gas/Oil CC Dataset – CAPEX for Less than 500-MW Plant Size



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

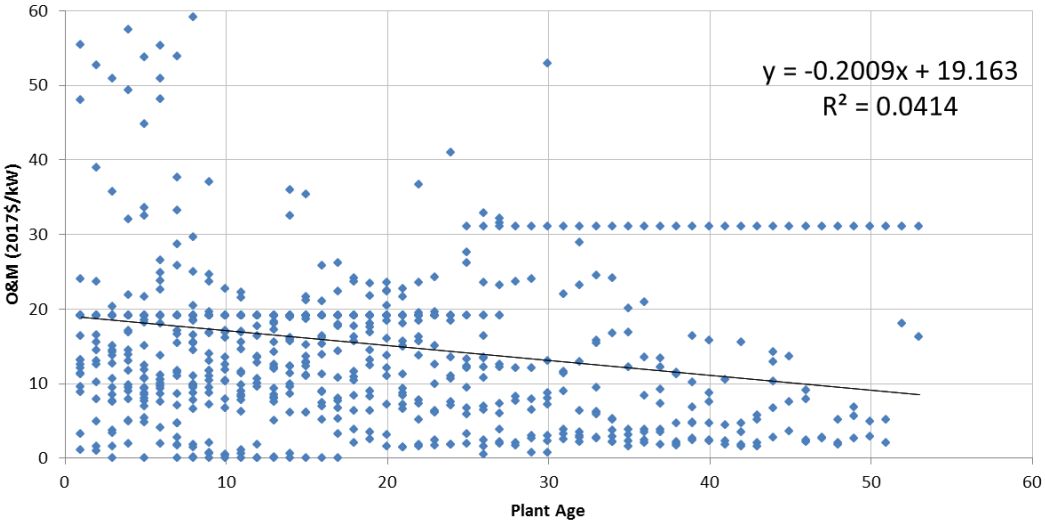
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of O&M spending for gas/oil CC plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

Table C-4 — Regression Statistics – CC O&M < 500 MW

		t statistic	*p-value*
Observations	766		
Simple Average ($/kW)	15.619		
Intercept	19.163	25.2973	4.82E-103
Slope	-0.201	-5.7467	1.31E-08
R^2	0.04143		

Figure C-4 — Gas/Oil CC Dataset – O&M for Less than 500-MW Plant Size



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
< 500 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	17.10	13.01	12.27	**15.62**	498	216	52	**766**
Net Total Capex - 2017 $/kW	16.83	17.78	21.01	**17.38**	499	214	52	**765**
Net Total O&M and Capex - 2017 $/kW	34.00	30.72	33.28	**33.03**	497	214	52	**763**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

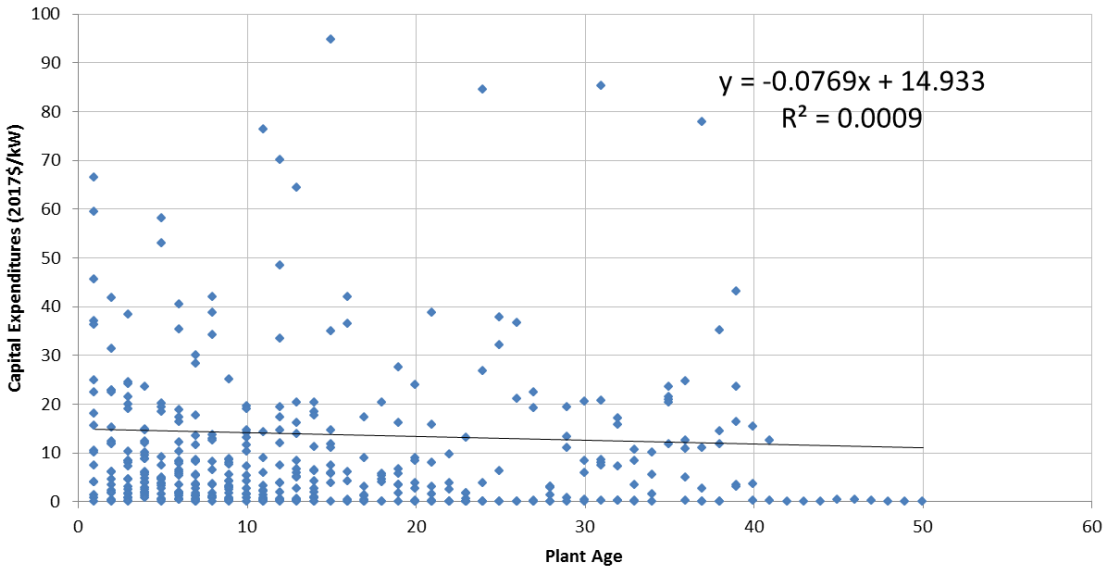
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.52, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-5 — Regression Statistics – CC CAPEX 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	426		
Simple Average ($/kW)	13.780		
Intercept	14.933	6.3972	4.19E-10
Slope	-0.077	-0.6252	5.32E-01
R^2	0.00092		

Figure C-5 — Gas/Oil CC Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

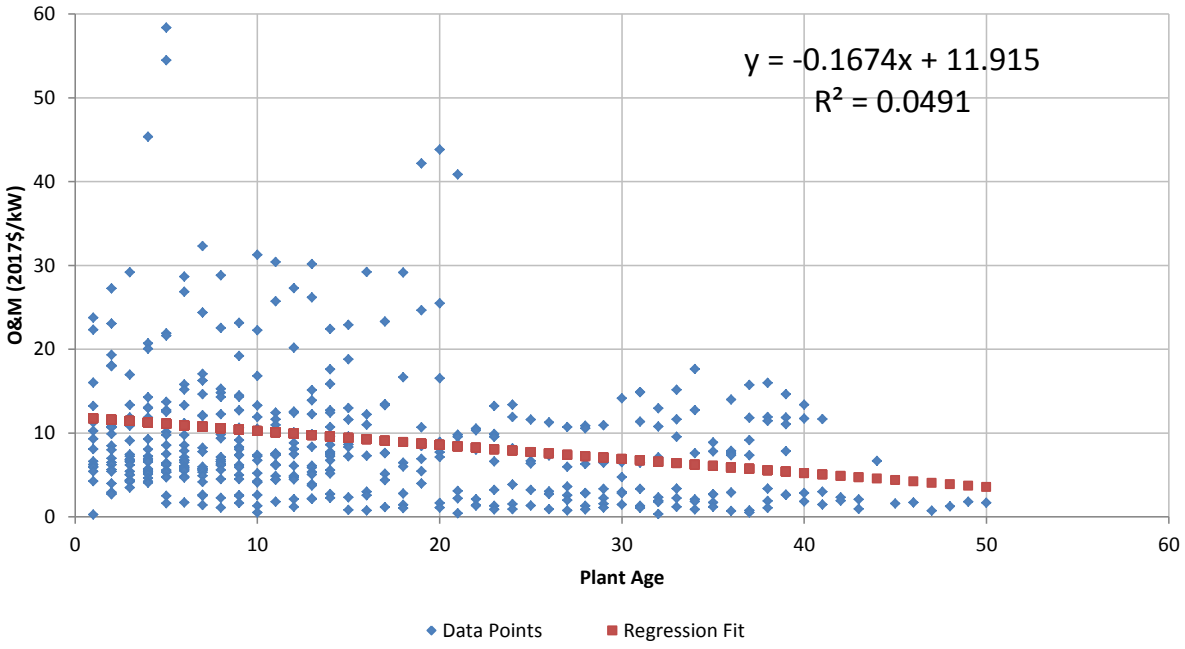
OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

Table C-6 — Regression Statistics – CC O&M 500 MW to 1,000 MW

		t statistic	*p-value*
Observations	445		
Simple Average ($/kW)	9.269		
Intercept	11.915	17.1008	1.04E-50
Slope	-0.167	-4.7810	2.38E-06
R^2	0.04907		

Figure C-6 — Gas/Oil CC Dataset – O&M for 500-MW to 1,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
500 MW - 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	10.68	6.50	2.78	**9.27**	307	124	14	**445**
Net Total Capex - 2017 $/kW	14.38	13.36	1.28	**13.78**	307	108	11	**426**
Net Total O&M and Capex - 2017 $/kW	25.06	20.38	4.15	**23.33**	306	108	11	**425**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

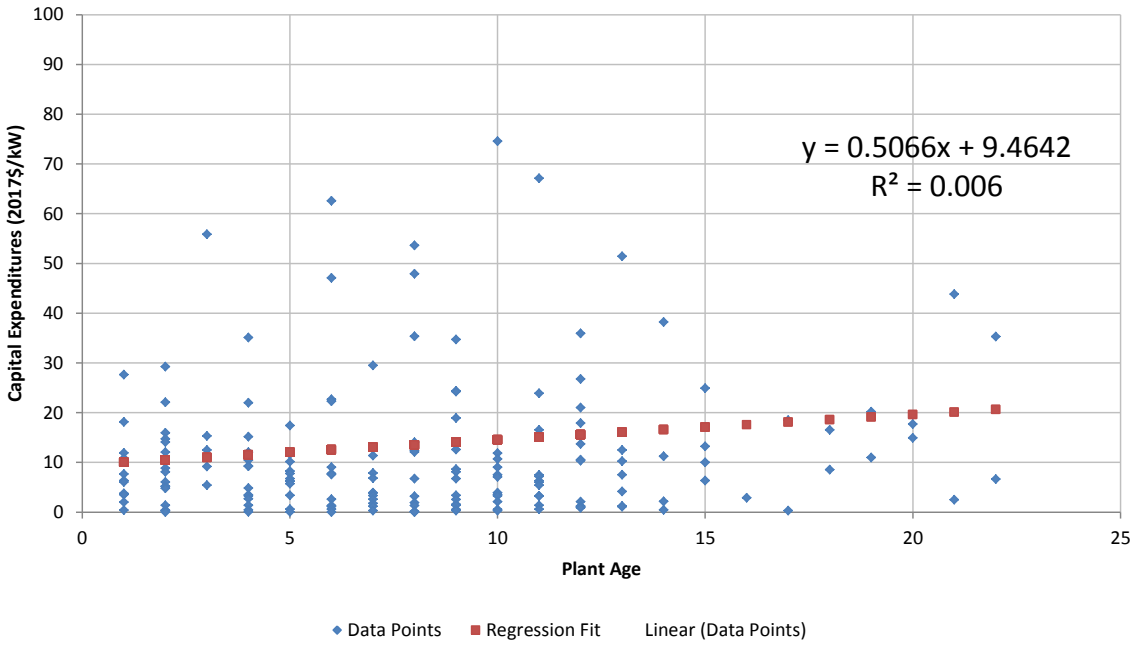
CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.30, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-7 — Regression Statistics – CC CAPEX > 1,000 MW

		t statistic	*p-value*
Observations	177		
Simple Average ($/kW)	13.566		
Intercept	9.464	2.0308	4.38E-02
Slope	0.507	1.0309	3.04E-01
R^2	0.00604		

Figure C-7 — Gas/Oil CC Dataset – CAPEX for Greater than 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

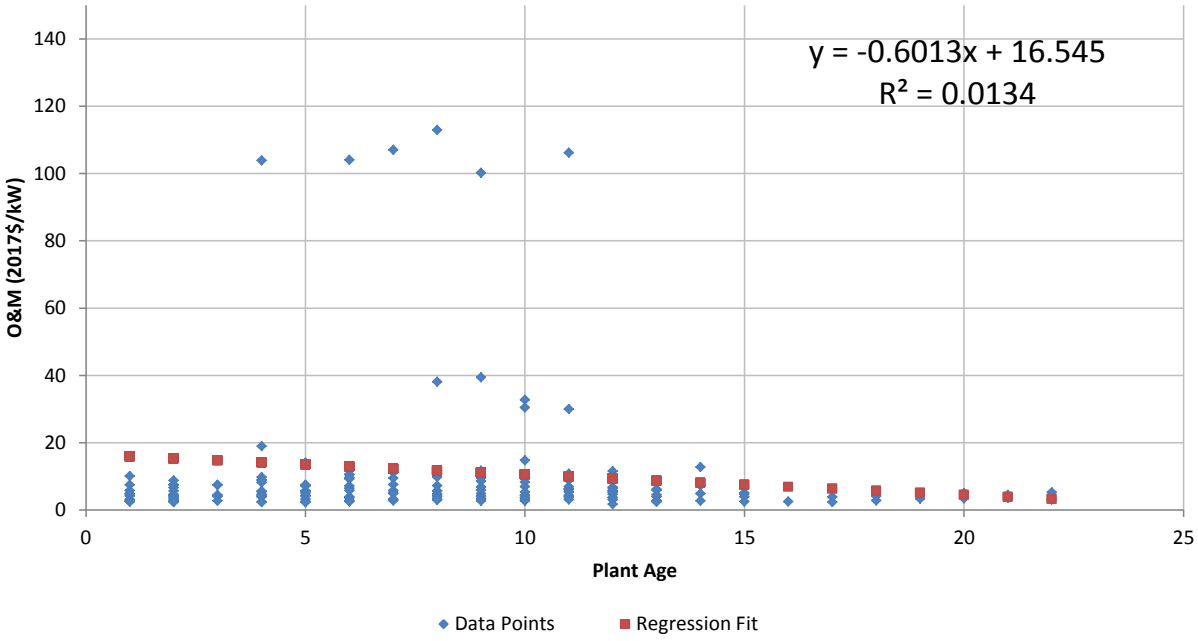
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.13, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

Table C-8 — Regression Statistics – CC O&M > 1,000 MW

		t statistic	*p-value*
Observations	177		
Simple Average ($/kW)	11.676		
Intercept	16.545	4.4651	1.43E-05
Slope	-0.601	-1.5389	1.26E-01
R^2	0.01335		

Figure C-8 — Gas/Oil CC Dataset – O&M for Greater than 1,000 MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
> 1000 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	11.85	4.14	-	**11.68**	173	4	0	**177**
Net Total Capex - 2017 $/kW	13.37	22.06	-	**13.57**	173	4	0	**177**
Net Total O&M and Capex - 2017 $/kW	25.22	26.20	-	**25.24**	173	4	0	**177**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

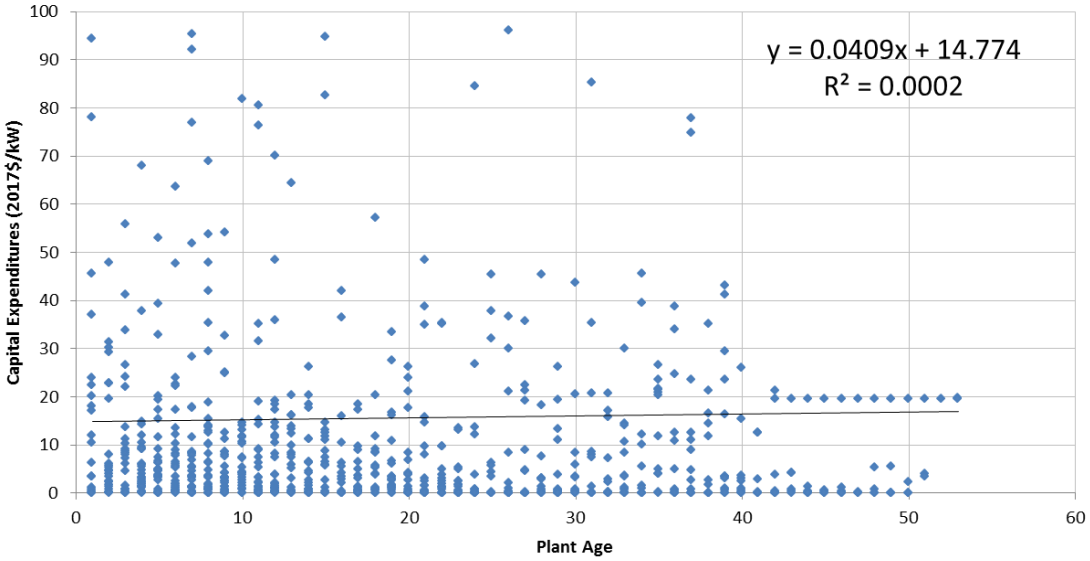
CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.71, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-9 — Regression Statistics – CC CAPEX for Capacity Factor < 50%

		t statistic	*p-value*
Observations	844		
Simple Average ($/kW)	15.554		
Intercept	14.774	5.7075	1.59E-08
Slope	0.041	0.3659	7.15E-01
R^2	0.00016		

Figure C-9 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor < 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

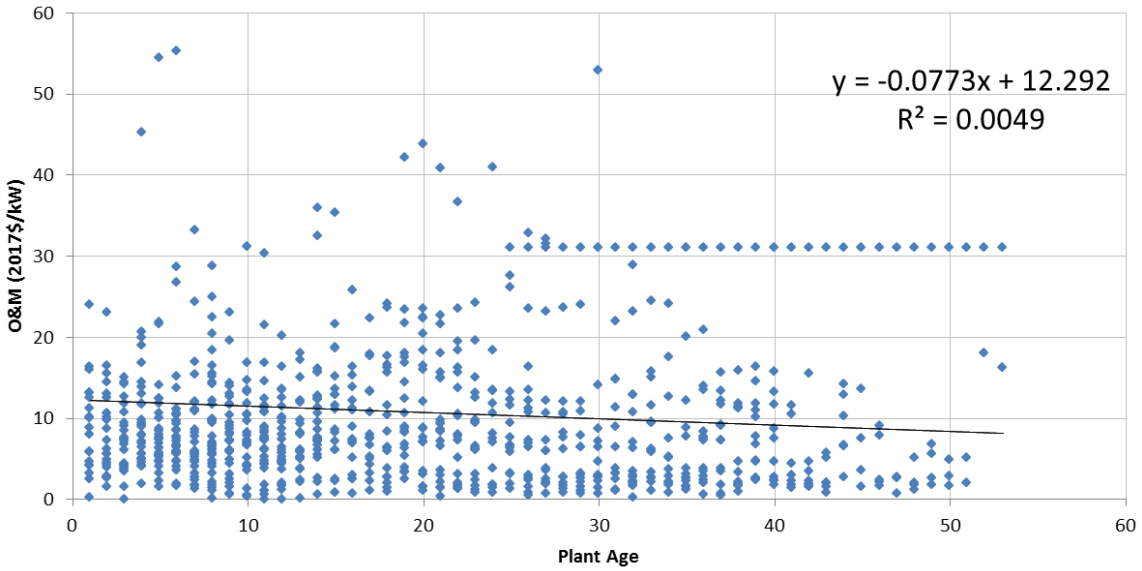
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

Table C-10 — Regression Statistics – CC O&M for Capacity Factor < 50%

		t statistic	*p-value*
Observations	864		
Simple Average ($/kW)	10.791		
Intercept	12.292	13.9850	3.33E-40
Slope	-0.077	-2.0625	3.95E-02
R^2	0.00491		

Figure C-10 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor < 50%



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, Capacity Factors 0 - 50%								
Net Total O&M- 2017 $/kW	11.54	9.65	10.26	**10.79**	500	298	66	**864**
Net Total Capex - 2017 $/kW	15.35	15.46	17.56	**15.55**	501	280	63	**844**
Net Total O&M and Capex - 2017 $/kW	26.95	25.41	28.19	**26.53**	499	280	63	**842**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

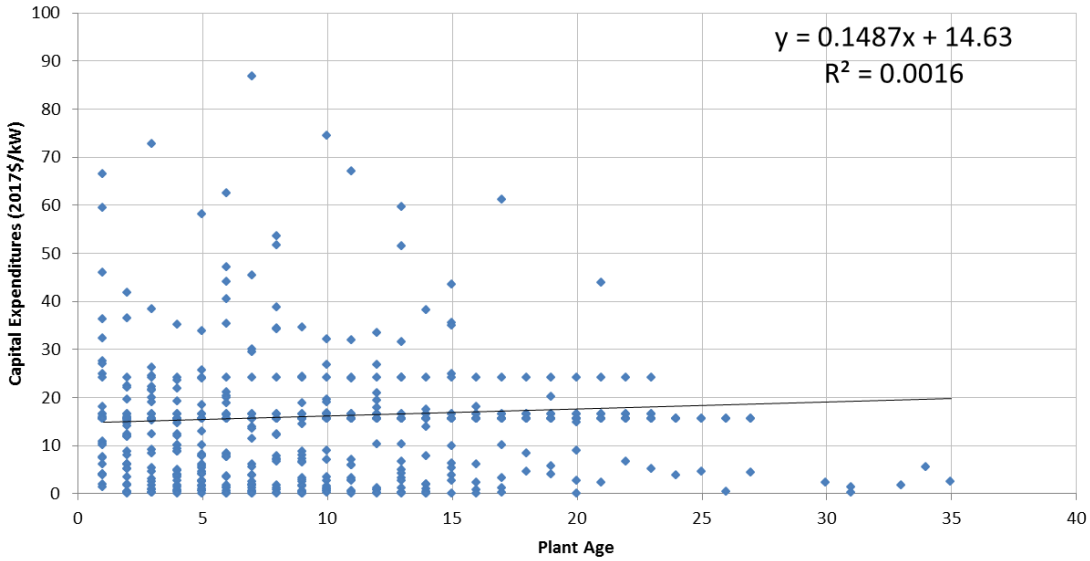
CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.37, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-11 — Regression Statistics – CC CAPEX for Capacity Factor > 50%

		t statistic	*p-value*
Observations	524		
Simple Average ($/kW)	16.104		
Intercept	14.630	7.3893	5.90E-13
Slope	0.149	0.9054	3.66E-01
R^2	0.00157		

Figure C-11 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor > 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

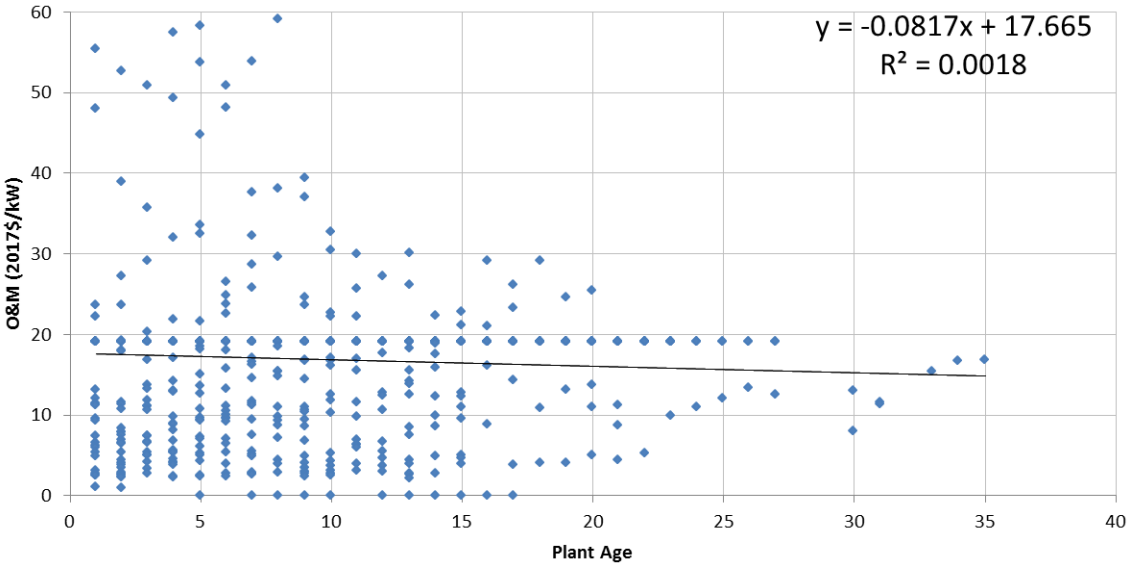
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below. Since the p-value for the age coefficient ("slope") is 0.33, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table C-12 — Regression Statistics – CC O&M for Capacity Factor > 50%

		t statistic	*p-value*
Observations	524		
Simple Average ($/kW)	16.855		
Intercept	17.665	17.5298	1.93E-54
Slope	-0.082	-0.9777	3.29E-01
R^2	0.00183		

Figure C-12 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor > 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, Capacity Factors 50% - 100%								
Net Total O&M- 2017 $/kW	16.90	16.44	-	**16.85**	478	46	0	**524**
Net Total Capex - 2017 $/kW	15.55	21.89	-	**16.10**	478	46	0	**524**
Net Total O&M and Capex - 2017 $/kW	32.46	38.32	-	**32.98**	477	46	0	**523**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.



Appendix D. Regression Analysis – Gas/Oil Combustion Turbine

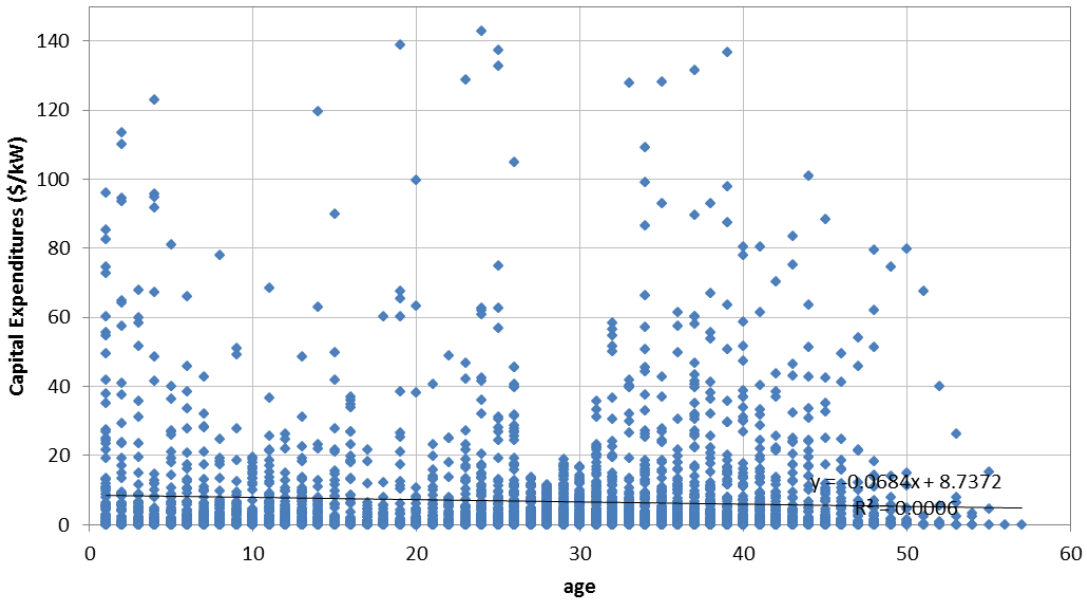
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.09, which is greater than 0.05, dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table D-1 — Regression Statistics – CT CAPEX for All MW

		t statistic	*p-value*
Observations	5065		
Simple Average ($/kW)	6.897		
Intercept	8.737	7.3087	3.12E-13
Slope	-0.068	-1.6948	9.02E-02
R^2	0.00057		

Figure D-1 — Gas/Oil CT Dataset – CAPEX for All Plant MW Sizes



Note: Age coefficient in above regression equation is not statistically significant.

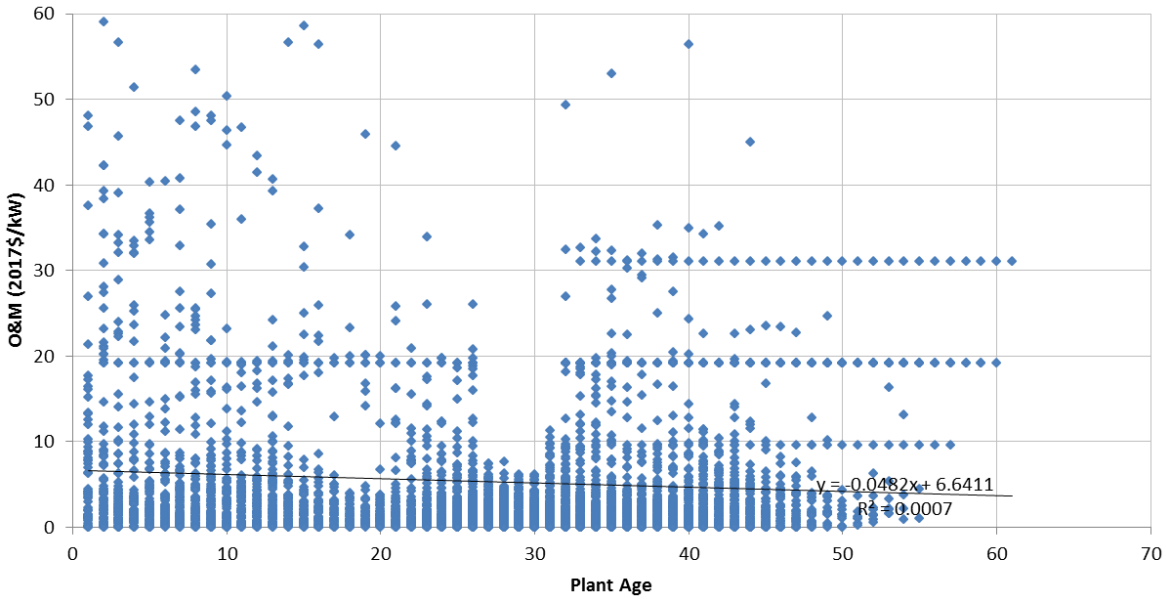
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of O&M spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.062, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table D-2 — Regression Statistics – CT O&M for All MW

		t statistic	*p-value*
Observations	5283		
Simple Average ($/kW)	5.331		
Intercept	6.641	8.5764	1.27E-17
Slope	-0.048	-1.8683	6.18E-02
R^2	0.00066		

Figure D-2 — Gas/Oil CT Dataset – O&M for All Plant MW Sizes



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	7.86	3.99	6.11	**5.33**	1,418	3,118	747	**5,283**
Net Total Capex - 2017 $/kW	9.17	5.78	7.40	**6.90**	1,360	3,054	651	**5,065**
Net Total O&M and Capex - 2017 $/kW	16.43	9.43	10.92	**11.49**	1,341	3,040	640	**5,021**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

CAPITAL EXPENDITURES – LESS THAN 100 MW

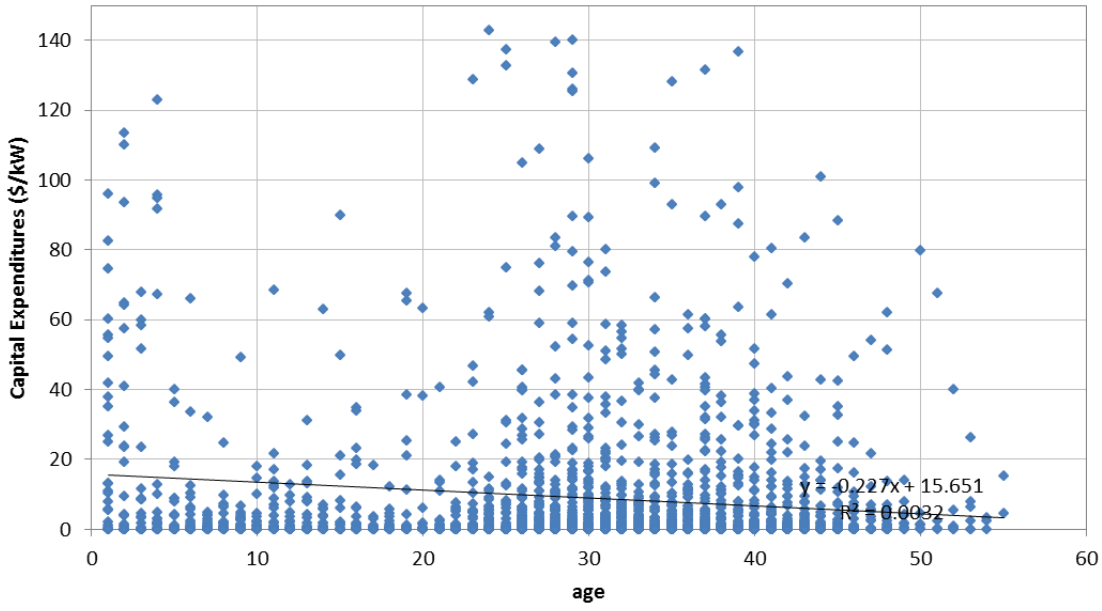
The results of the regression analysis of CAPEX spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.002, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

Annual CAPEX spending in 2017 $/kW-year = 15.651 + (-0.227 × age)

Table D-3 — Regression Statistics – CT CAPEX < 100 MW

		t statistic	*p-value*
Observations	2,911		
Simple Average ($/kW)	9.003		
Intercept	15.651	6.6753	2.94E-11
Slope	-0.227	-3.0345	2.43E-03
R^2	0.00316		

Figure D-3 — Gas/Oil CT Dataset – CAPEX for Less than 100-MW Plant Size



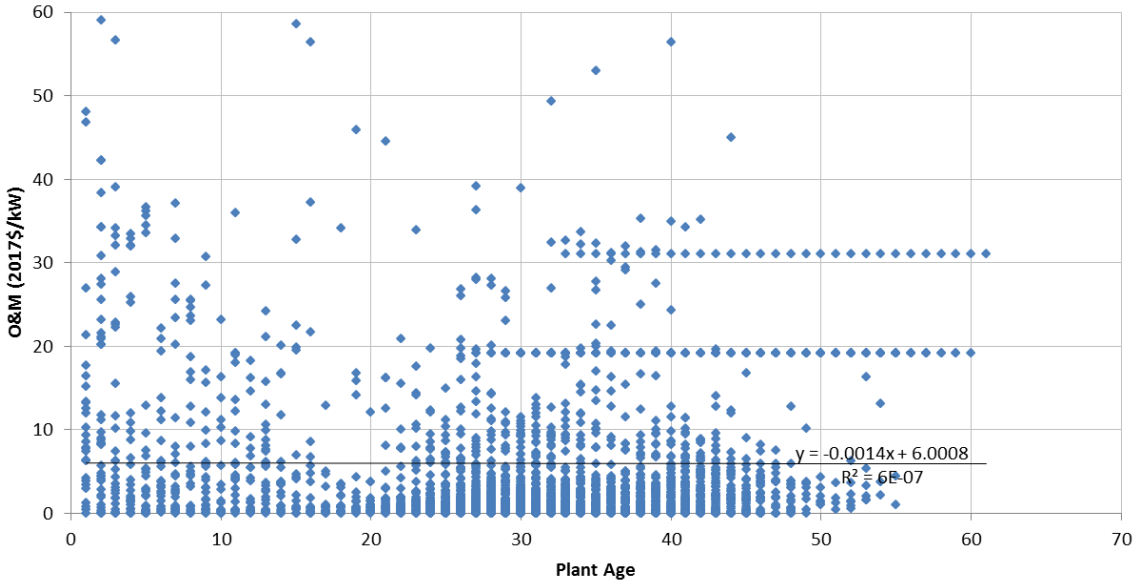
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 100 MW

The results of the regression analysis of O&M spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.966, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table D-4 — Regression Statistics – CT O&M < 100 MW

		t statistic	*p-value*
Observations	3,062		
Simple Average ($/kW)	5.958		
Intercept	6.001	5.5008	4.09E-08
Slope	-0.001	-0.0423	9.66E-01
R^2	0.00000		

Figure D-4 — Gas/Oil CT Dataset – O&M for Less than 100-MW Plant Size



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
< 100 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	8.76	4.93	7.40	**5.96**	489	2,060	513	**3,062**
Net Total Capex - 2017 $/kW	15.08	7.98	6.64	**9.00**	497	1,999	415	**2,911**
Net Total O&M and Capex - 2017 $/kW	24.04	12.31	10.26	**14.02**	489	1,978	406	**2,873**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

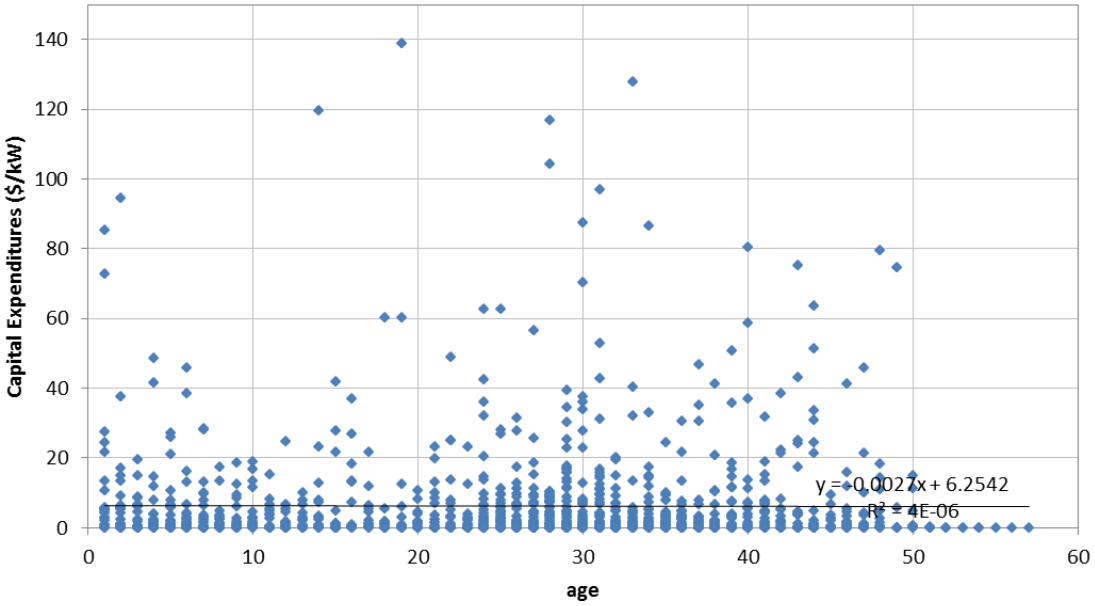
CAPITAL EXPENDITURES – BETWEEN 100 MW AND 300 MW

The results of the regression analysis of CAPEX spending for CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.939, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table D-5 — Regression Statistics – CT CAPEX 100 MW to 300 MW

		t statistic	*p-value*
Observations	1,350		
Simple Average ($/kW)	6.183		
Intercept	6.254	6.0376	2.02E-09
Slope	-0.003	-0.0768	9.39E-01
R^2	0.00000		

Figure D-5 — Gas/Oil CT Dataset – CAPEX for Between 100-MW and 300-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 100 MW AND 300 MW

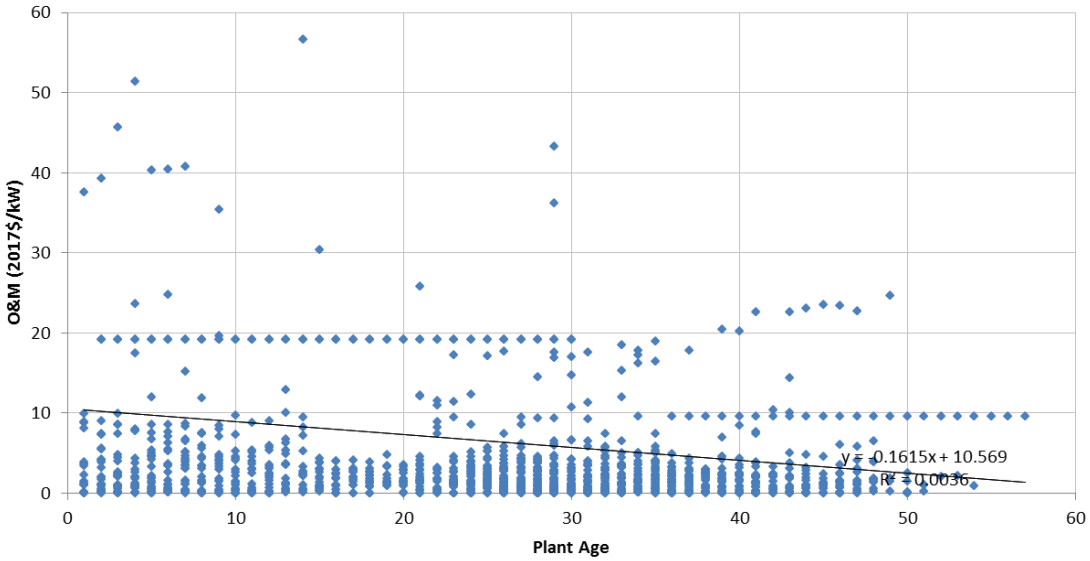
The results of the regression analysis of O&M spending for gas/oil CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.023, which is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 10.569 + (-0.162 × age)

Table D-6 — Regression Statistics – CT O&M 100 MW to 300 MW

		t statistic	*p-value*
Observations	1,416		
Simple Average ($/kW)	6.430		
Intercept	10.569	5.1759	2.59E-07
Slope	-0.162	-2.2723	2.32E-02
R^2	0.00364		

Figure D-6 — Gas/Oil CT Dataset – O&M for Between 100-MW and 300-MW Plant Size



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
100 MW - 300 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	9.97	5.18	3.24	**6.43**	442	794	180	**1,416**
Net Total Capex - 2017 $/kW	6.32	6.07	6.38	**6.18**	407	762	181	**1,350**
Net Total O&M and Capex - 2017 $/kW	15.14	9.09	9.66	**10.98**	402	759	180	**1,341**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

CAPITAL EXPENDITURES – GREATER THAN 300 MW

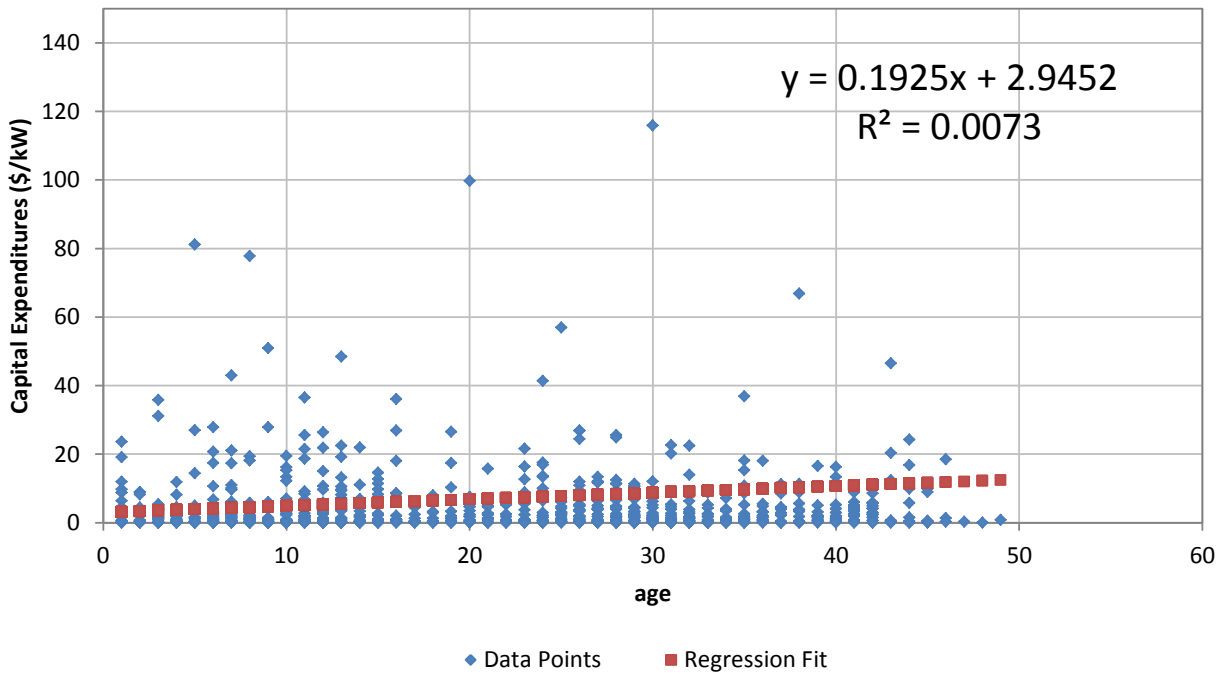
The results of the regression analysis of CAPEX spending for gas/oil CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.010, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

Annual CAPEX spending in 2017 $/kW-year = 2.945 + (0.193 × age)

Table D-7 — Regression Statistics – CT CAPEX > 300 MW

		t statistic	*p-value*
Observations	909		
Simple Average ($/kW)	6.952		
Intercept	2.945	1.6382	1.017E-01
Slope	0.193	2.5842	0.010
R^2	0.00731		

Figure D-7 — Gas/Oil CT Dataset – CAPEX for Greater than 300-MW Plant Size



OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 300 MW

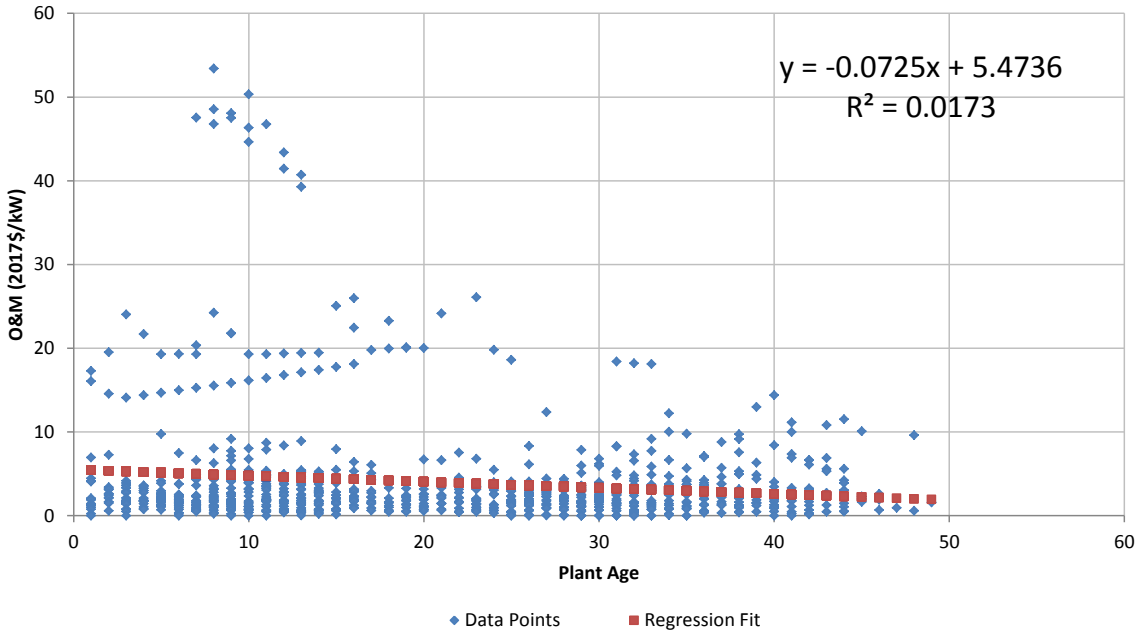
The results of the regression analysis of O&M spending for CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 5.474 + (-0.072 × age)

Table D-8 — Regression Statistics – CT O&M > 300 MW

		t Statistic	*p-value*
Observations	938		
Simple Average ($/kW)	3.994		
Intercept	5.474	12.8980	3.75E-35
Slope	-0.072	-4.0612	5.29E-05
R^2	0.01732		

Figure D-8 — Gas/Oil CT Dataset – O&M for Greater than 300-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
> 300 MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	5.03	2.78	3.46	**3.99**	488	396	54	**938**
Net Total Capex - 2017 $/kW	5.26	7.58	16.50	**6.95**	457	397	55	**909**
Net Total O&M and Capex - 2017 $/kW	9.30	10.38	20.11	**10.42**	451	396	54	**901**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.



Appendix E. Regression Analysis – Conventional Hydroelectric

CAPITAL EXPENDITURES – ALL PLANT SIZES

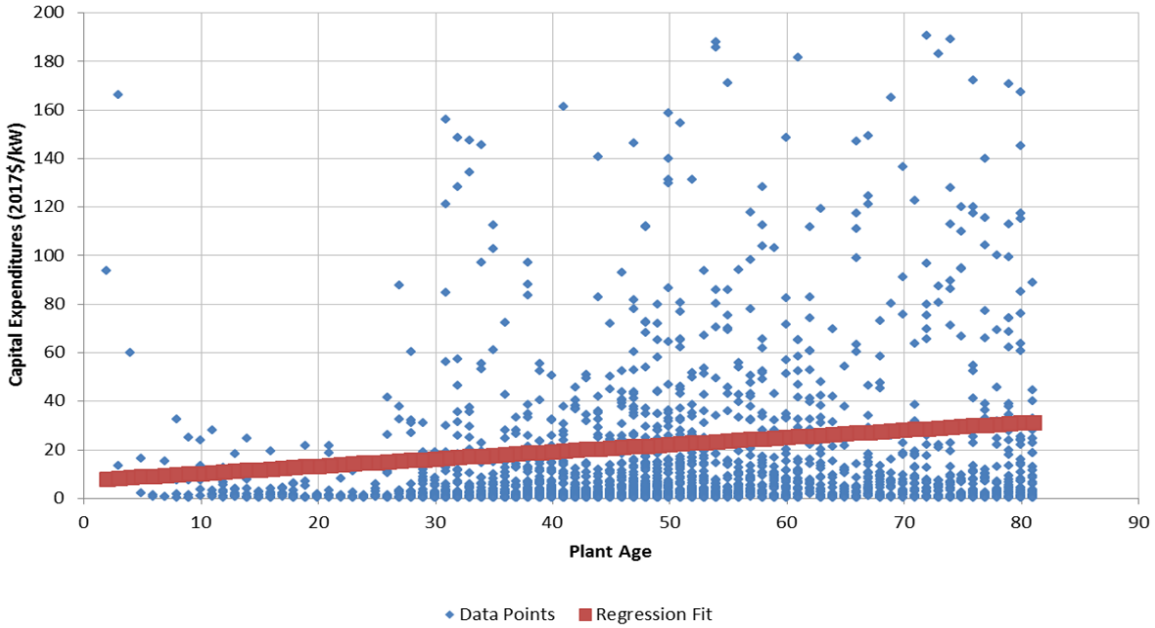
The results of the linear regression analysis of CAPEX spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

Annual CAPEX spending in 2017 $/kW-year = 7.269 + (0.296 × age)

Table E-1 — Regression Statistics – Hydroelectric CAPEX for All MW

		t statistic	*p-value*
Observations	2180		
Simple Average ($/kW)	21.999		
Intercept	7.269	1.4681	1.42E-01
Slope	0.296	3.1441	1.69E-03
R^2	0.00452		

Figure E-1 — Conventional Hydroelectric Dataset – CAPEX for All MW Plant Sizes



OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

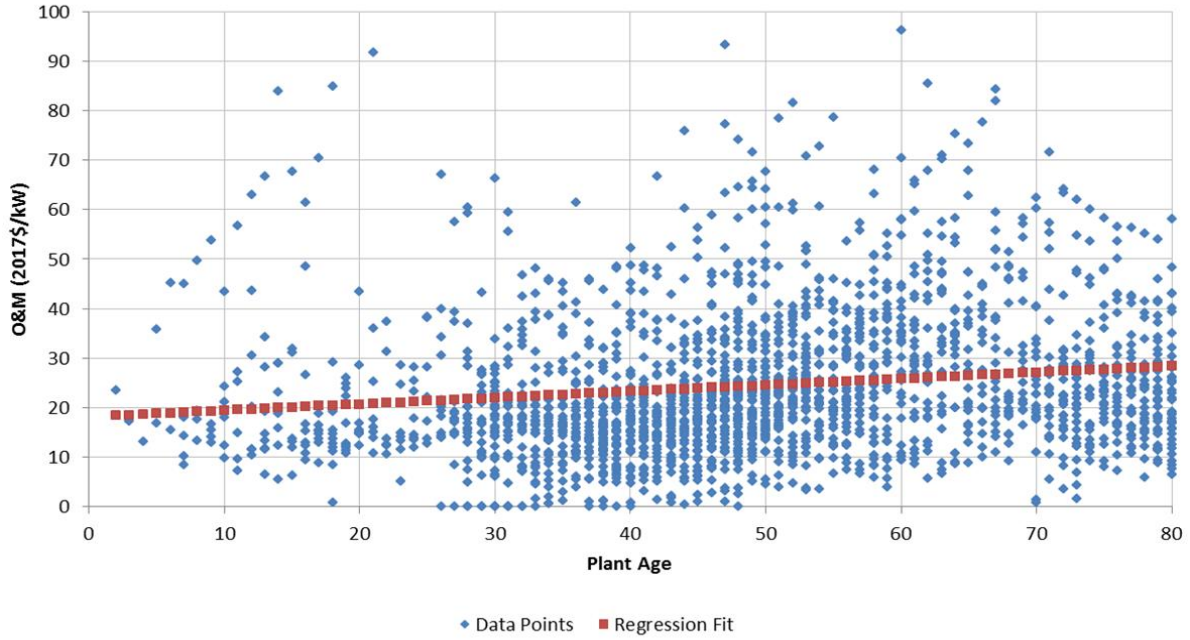
The results of the linear regression analysis of O&M spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 22.360 + (0.073 × age)

Table E-2 — Regression Statistics – Hydroelectric O&M for All MW

		t statistic	*p-value*
Observations	1,272		
Simple Average ($/kW)	24.473		
Intercept	22.360	13.7360	3.92E-40
Slope	0.073	2.5053	1.24E-02
R^2	0.00492		

Figure E-2 — Conventional Hydroelectric – O&M for All MW Plant Sizes





Appendix F. Regression Analysis – Pumped Hydroelectric Storage

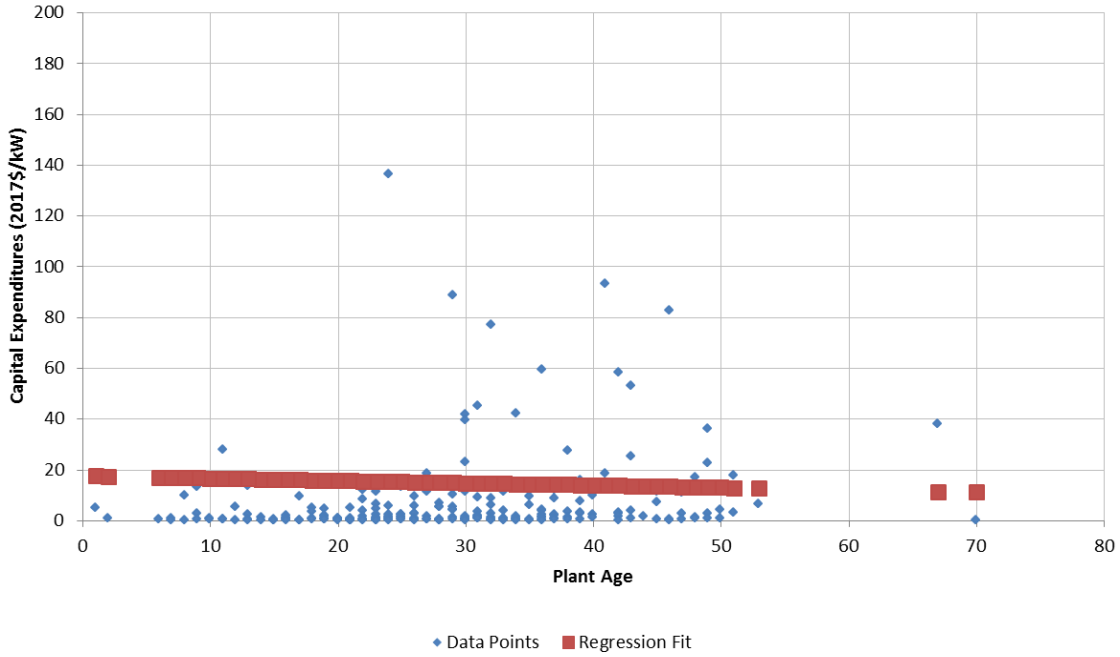
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

Table F-1 — Regression Statistics – Pumped Hydroelectric CAPEX for All MW

		t statistic	*p-value*
Observations	227		
Simple Average ($/kW)	11.398		
Intercept	-6.907	-0.4501	6.53E-01
Slope	0.743	1.2723	2.06E-01
R^2	0.01278		

Figure F-1 — Pumped Hydroelectric Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

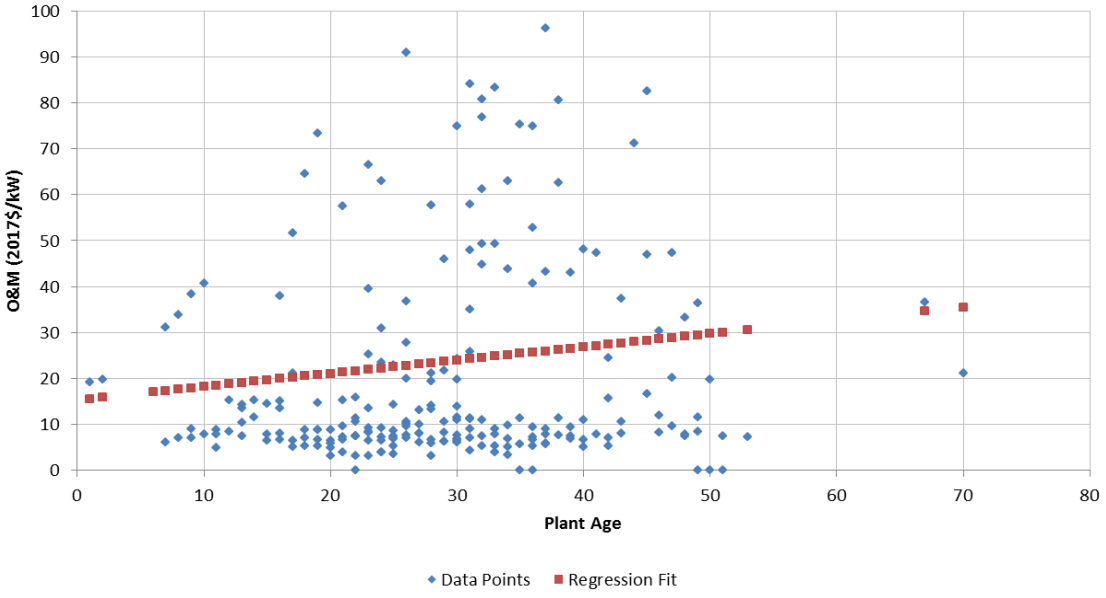
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

Table F-2 — Regression Statistics – Pumped Hydroelectric O&M for All MW

		t statistic	*p-value*
Observations	226		
Simple Average ($/kW)	23.634		
Intercept	15.296	2.9021	4.08E-03
Slope	0.288	1.7010	9.03E-02
R^2	0.01275		

Figure F-2 — Pumped Hydroelectric – O&M for All Plant MW Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

	Average $/kW (years 1 - 20) =	Average $/kW (years 21 - 40) =	Average $/kW (years 41 - 80) =	**Average $/kW (all years) =**	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	**Data Points (all years) =**
All MW, All Capacity Factors								
Net Total O&M- 2017 $/kW	18.97	23.41	31.00	**23.63**	50	140	36	**226**
Net Total Capex - 2017 $/kW	22.94	11.93	14.92	**14.83**	50	141	36	**227**
Net Total O&M and Capex - 2017 $/kW	41.91	35.34	45.92	**38.46**	--	--	--	--

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing pumped hydroelectric storage plants are described in Section 8.

Appendix G. Regression Analysis – Solar Photovoltaic

CAPITAL EXPENDITURES

Annual CAPEX, labeled in FERC Form 1 as TCP, are broken down into subcategories, including:

- Land & Land Rights
- Structures & Improvements
- Reservoirs, Dams & Waterways
- Water Wheels
- Turbines & Generators
- Accessory Electric Equipment
- Equipment
- Asset Retirement Costs
- Roads, and Railroads & Bridges

These subcategories are based on traditional power generation technologies and have minimal applicability to solar PV. Expected CAPEX for solar PV, such as inverter replacement and repair or module replacement, are clearly not applicable to any of the categories listed in FERC Form 1.

In the FERC Form 1 data, only 10 of the solar PV sites had a breakdown of TCP into the above subcategories, with even fewer providing such a breakdown for more than one year. As discussed in Section 9, the year-over-year change in TCP is the sole source of annual CAPEX information in FERC Form 1. Of this data, Sargent & Lundy determined that a significant portion of it needed to be filtered out due to the following reasons:

- A negative change in the TCP between two consecutive years
- A change in the capacity of the plant greater than 20%
- A significant increase in TCP without a capacity increase
- Large unexplained fluctuations (e.g., negative to positive) in TCP from year to year
- Large gaps in annual data

After filtering out clearly suspect data, about one-third of the remaining data was for plants having only three years of data or less. In addition, many of the plants reported no changes in TCP, suggesting that most annual expenditures at those sites were being reported as O&M rather than being capitalized.

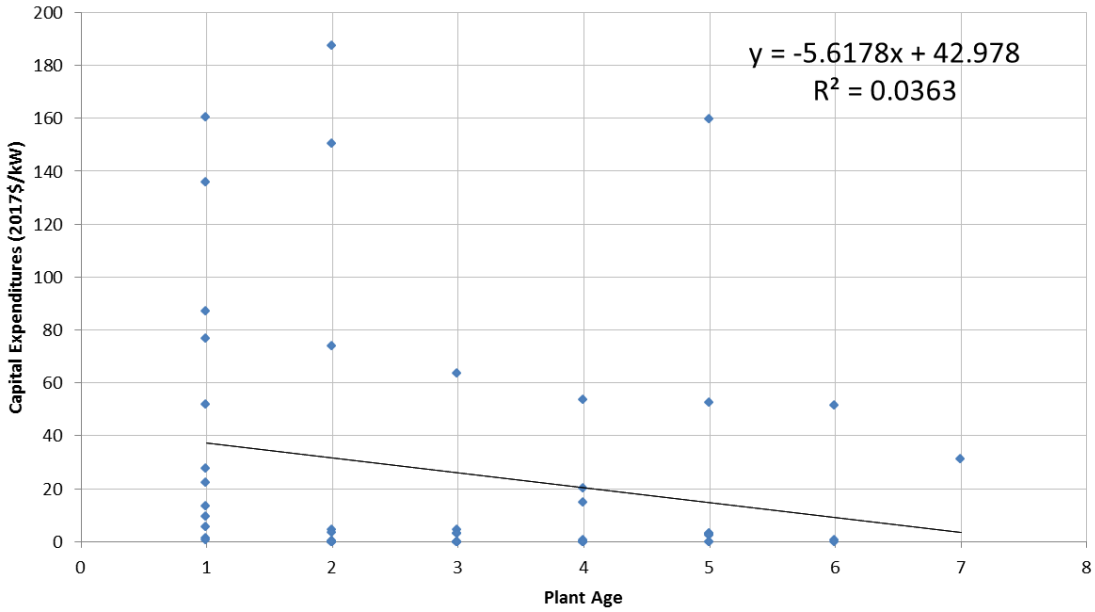
Thus, Sargent & Lundy had to rely on a limited dataset for solar PV consisting of 15 sites. The average change in TCP for these sites was approximately $26/kW-year. Based on the available FERC Form 1 information, it cannot be determined whether this change in TCP was due to typical CAPEX for solar PV, such as inverter or module replacement, or other factors.

The results of the linear regression analysis of CAPEX spending for solar PV plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.16, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). In addition, as indicated in the table below, there are a relatively small number of data points for CAPEX (less than 60 points). The average CAPEX across all years is approximately $26/kW-year (2017 dollars).

Table G-1 — Regression Statistics – Solar PV CAPEX for All MW

		t statistic	*p-value*
Observations	57		
Simple Average ($/kW)	26.026		
Intercept	42.978	3.2248	2.12E-03
Slope	-5.618	-1.4387	1.56E-01
R^2	0.03627		

Figure G-1 — Solar PV Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment, inspecting modules for damage, inspecting mounting systems, and checking invertor settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

The total production cost, which is the sum of the total operating expense and total maintenance expense, was reported for slightly over half of the sites. Of the sites reporting, several sites only reported this data in certain years, leaving gaps in the data. Subcategories for operating costs and maintenance cost were provided in the FERC Form 1 data, but rarely was the reported data broken into subcategories.

Sargent & Lundy organized the FERC Form 1 data into two presentation formats. In the first format, the annual O&M cost was averaged across all years of the reported data to obtain the average annual O&M cost per plant. This resulted in approximately 60 data points. In the second format, the annual O&M cost was averaged across each year of operation. This resulted in approximately 200 data points. The average O&M cost results are not equal between the two presentation formats. Table G-2 provides a simple example of these differing results, using FERC Form 1 O&M data from three plants.

Table G-2 — Example of Calculation Method Differences

	O&M Cost ($/kW-year)															
Age (Years)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	Plant Average
Example Plant 1	127.8	0.0	0.1	0.0	-	-	-	-	-	-	-	-	-	-	-	32.0
Example Plant 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Example Plant 3	32.2	15.3	24.8	-	-	-	-	-	-	-	-	-	-	-	-	24.1

Example Average (All Data Points)	9.1
Example Average (of Plant Averages)	18.7

In the example above, a single plant with more data points is able to sway the average O&M cost across the three plants. The values calculated below are based on averaged data points (i.e., a data point is the average annual O&M cost across the reported data for a given plant).

Figure G-2 and Figure G-3 show the average site O&M cost, expressed in $/MWh, for sites with a capacity less than 5 MW and greater than 5 MW, respectively. In general, these figures show a high level of variability across sites, with smaller sites having a higher O&M cost per MWh produced. Several data points were for sites having very low capacity factors (less than 5%), which also results in higher O&M costs per MWh. For the sites greater than 5 MW, the average O&M cost was $8.5/MWh. When expressed on the basis of cost per kW of capacity (see Figure G-4 and Figure G-5), the average O&M for sites greater than 5 MW was $15/kW-year.

Figure G-2 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (< 5 MW)

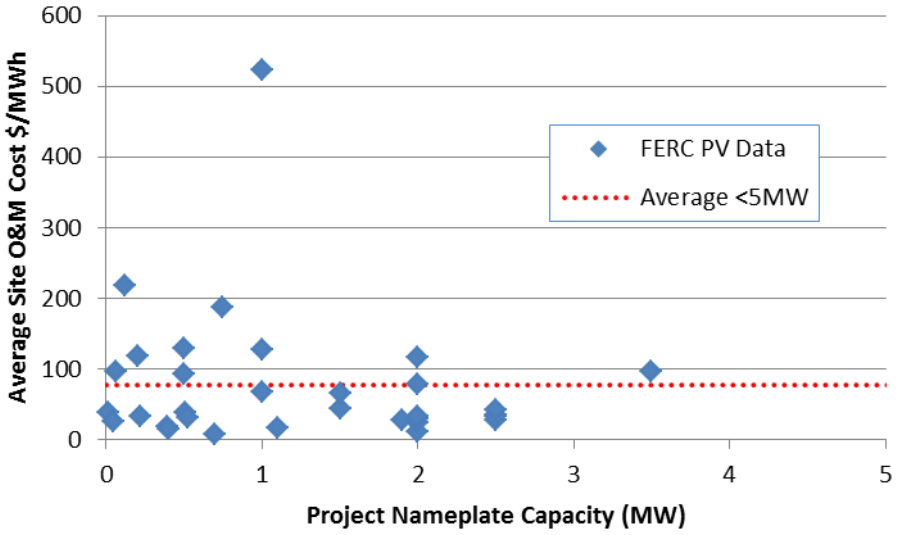


Figure G-3 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (> 5 MW)

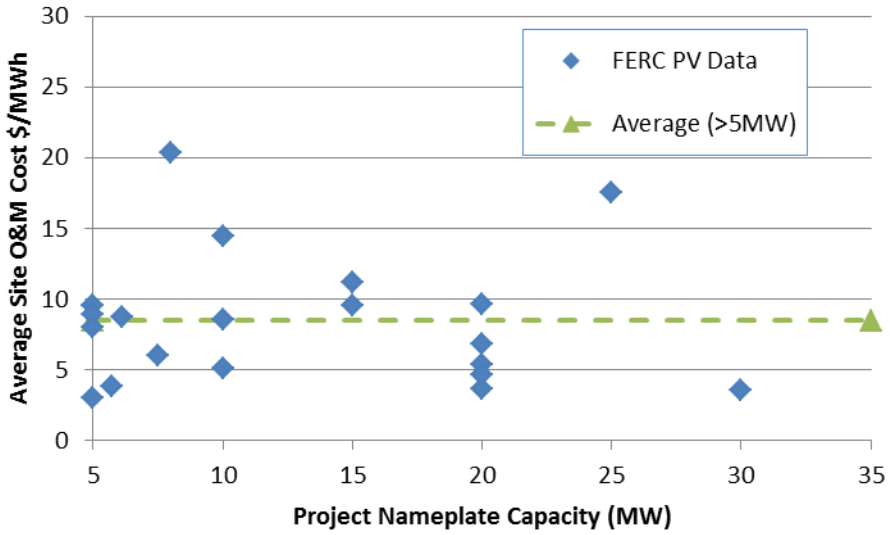


Figure G-4 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (< 5 MW)

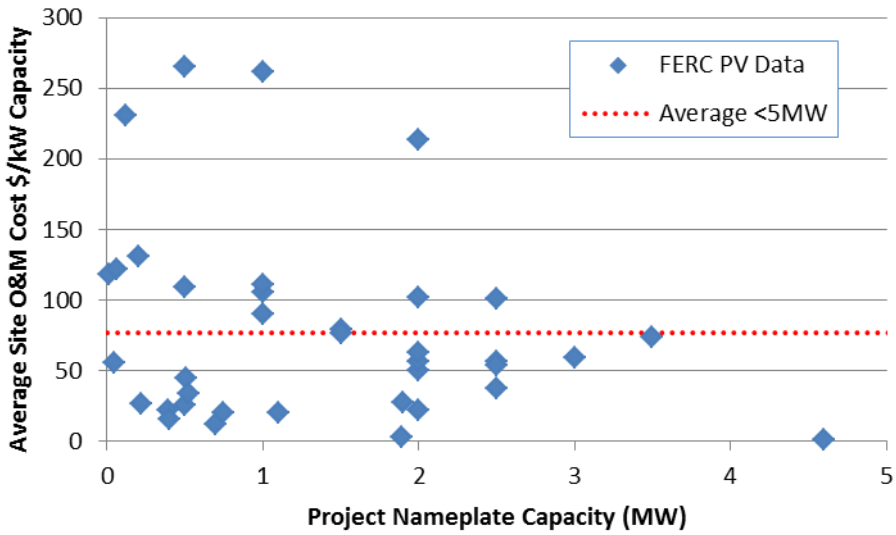
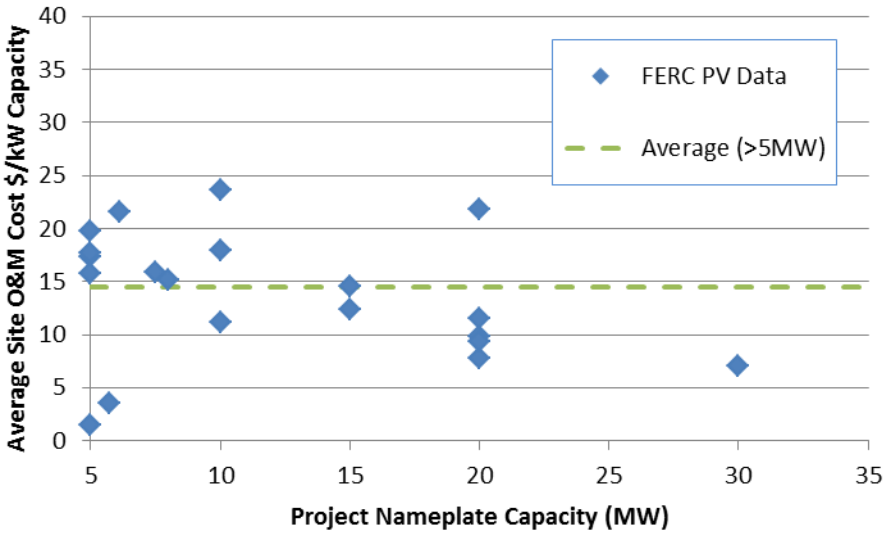


Figure G-5 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (> 5 MW)



The figures below show the annual site O&M cost (in $/MWh and $/kW-year) versus the age of the project. In general, little correlation can be seen between age and O&M cost.

Figure G-6 — Annual Site O&M Cost per MWh vs. Age of Project

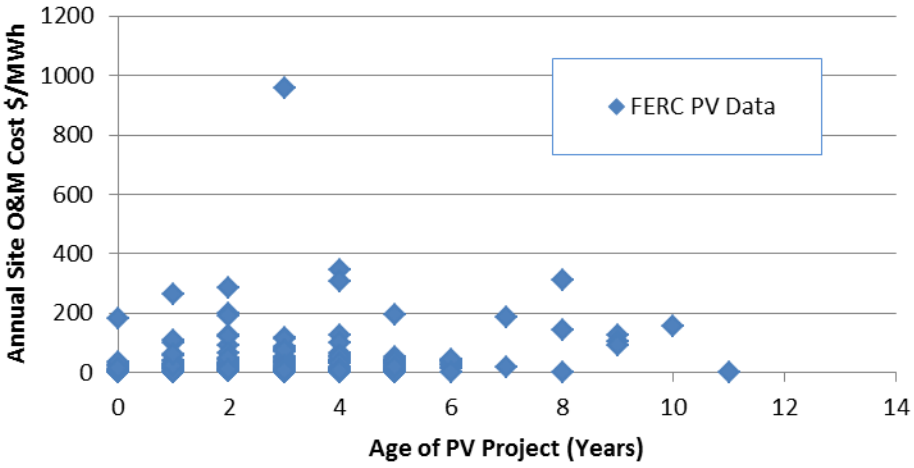
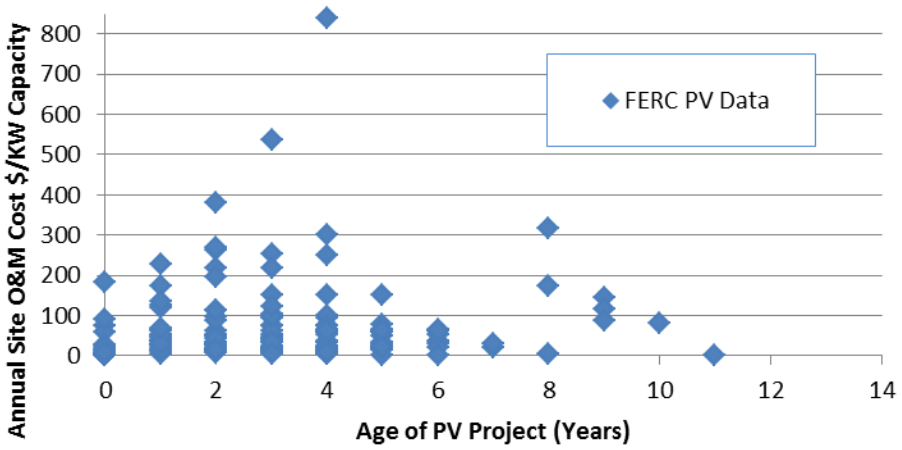


Figure G-7 — Annual Site O&M Cost per kW-Year Capacity vs. Age of Project



Sargent & Lundy compiled O&M data from other sources in Table G-3 below for comparison against the FERC data. In general, the O&M costs in $/kW-year capacity are in the same range as the FERC data for sites over 5-MW capacity.

Table G-3 — Summary of Industry O&M Cost Data for Solar PV

O&M Cost Sources	O&M Cost $/kW-yr	Notes	Report Source Data Year
NREL & Sunshot	15	Fixed	2015
NREL & Sunshot	18	Single-Axis Tracking	2015
Sunshot + NREL	20.5	Good O&M	2016
Sunshot + NREL	25.0	Optimal O&M	2016
IRENA Power to Change	10	Minimum	2015
IRENA Power to Change	18	Maximum	2015
Utility Scale Solar	17	Overall	2014
Utility Scale Solar 2016	7	Minimum	2016
Utility Scale Solar 2016	27	Maximum	2016
Utility Scale Solar 2016	18	Mean	2016
NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017	15.4	Fixed LCOE Assumption	2017
NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018	18.5	SAT LCOE Assumption	2017

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing solar PV plants are described in Section 9.



Appendix H. Regression Analysis – Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

Appendix I. Regression Analysis – Geothermal

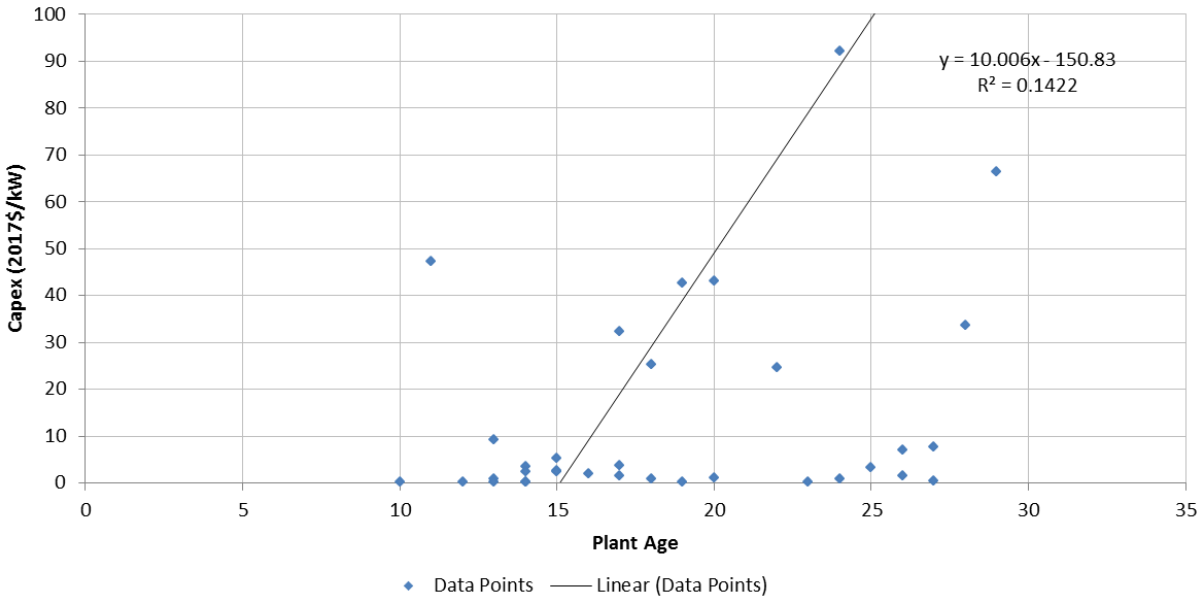
CAPITAL EXPENDITURES

The results of the linear regression analysis of CAPEX spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Although the p-value is less than 0.05, the dataset is inconclusive because the intercept is negative due to no plants reporting data between ages and 0 and 10.

Table I-1 — Regression Statistics – Geothermal CAPEX for All MW

		t statistic	*p-value*
Observations	36		
Simple Average ($/kW)	40.948		
Intercept	-150.830	-1.7907	8.23E-02
Slope	10.006	2.3736	2.34E-02
R^2	0.14215		

Figure I-1 — Geothermal Dataset – CAPEX for All MW Plant Sizes



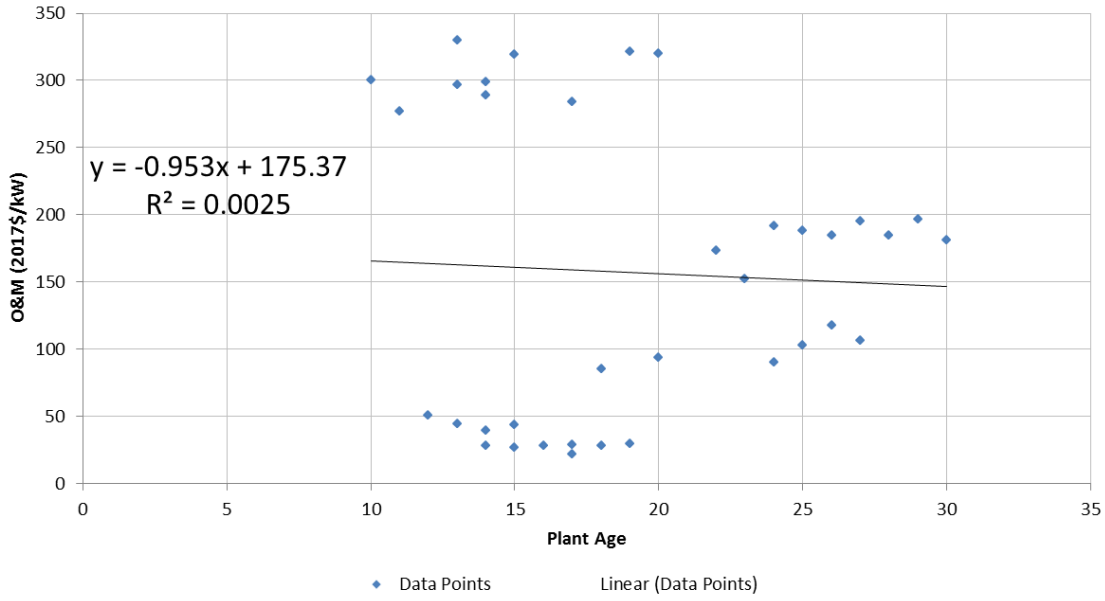
OPERATIONS & MAINTENANCE EXPENDITURES

The results of the linear regression analysis of O&M spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.071, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table I-2 — Regression Statistics – Geothermal O&M for All MW

		t Statistic	*p-value*
Observations	36		
Simple Average ($/kW)	157.103		
Intercept	175.369	2.6984	1.08E-02
Slope	-0.953	-0.2930	7.71E-01
R^2	0.00252		

Figure I-2 — Geothermal Dataset – O&M for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table I-3 — Geothermal All MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (Years 11-15)	Average $/kW-yr (Years 16-20)	Average $/kW-yr (Years 21-25)	Average $/kW-yr (Years 26-30)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (Years 21-25)	Data Points (Years 26-30)	Data Points (All Years)
All MW, All Capacity Factors														
Net Total O&M – 2017 $/kW-yr	--	300.62	170.44	124.24	149.97	166.77	**157.10**	--	1	12	10	6	7	**36**
Net Total CAPEX – 2017 $/kW-yr	--	--	72.05	30.16	27.64	114.45	**40.94**	--	1	12	10	6	7	**36**

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing geothermal plants are described in Section 11.

Appendix J. Regression Analysis – Wind

CAPITAL EXPENDITURES

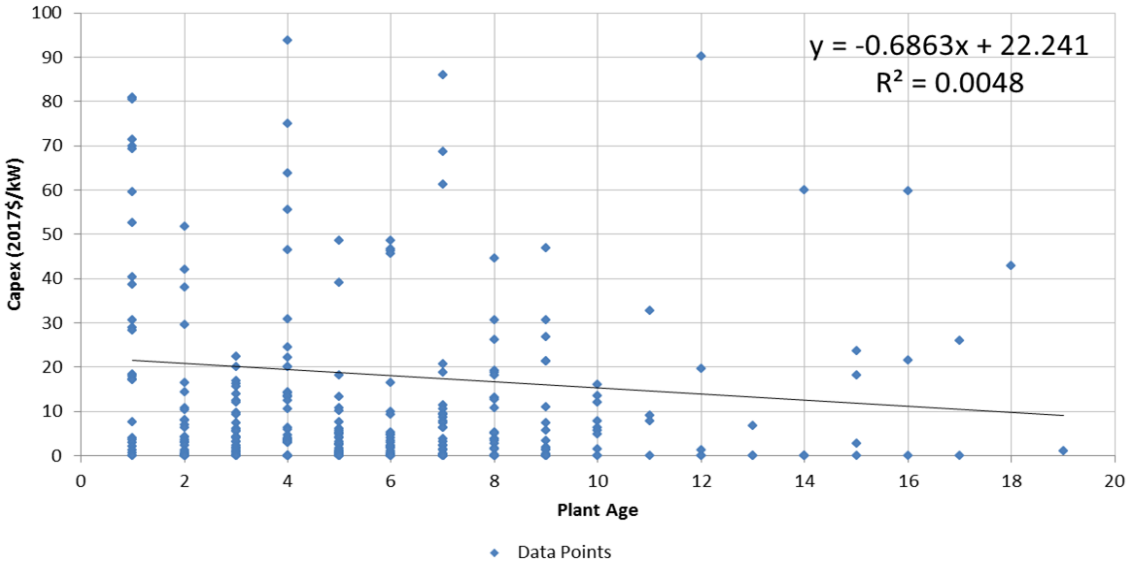
Full Dataset

The results of the linear regression analysis of CAPEX spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table J-1 — Regression Statistics – Wind CAPEX for All MW

		t Statistic	*p-value*
Observations	310		
Simple Average ($/kW)	18.285		
Intercept	22.241	5.7807	1.82E-08
Slope	-0.686	-1.2194	2.24E-01
R^2	0.00480		

Figure J-1 — Wind Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table J-2 — Wind All MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (Years 11-15)	Average $/kW-yr (Years 16-20)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (All Years)
All MW, All Capacity Factors										
Net Total CAPEX – 2017 $/kW-yr	21.06	10.97	32.62	21.60	**18.29**	168	112	23	7	**310**

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

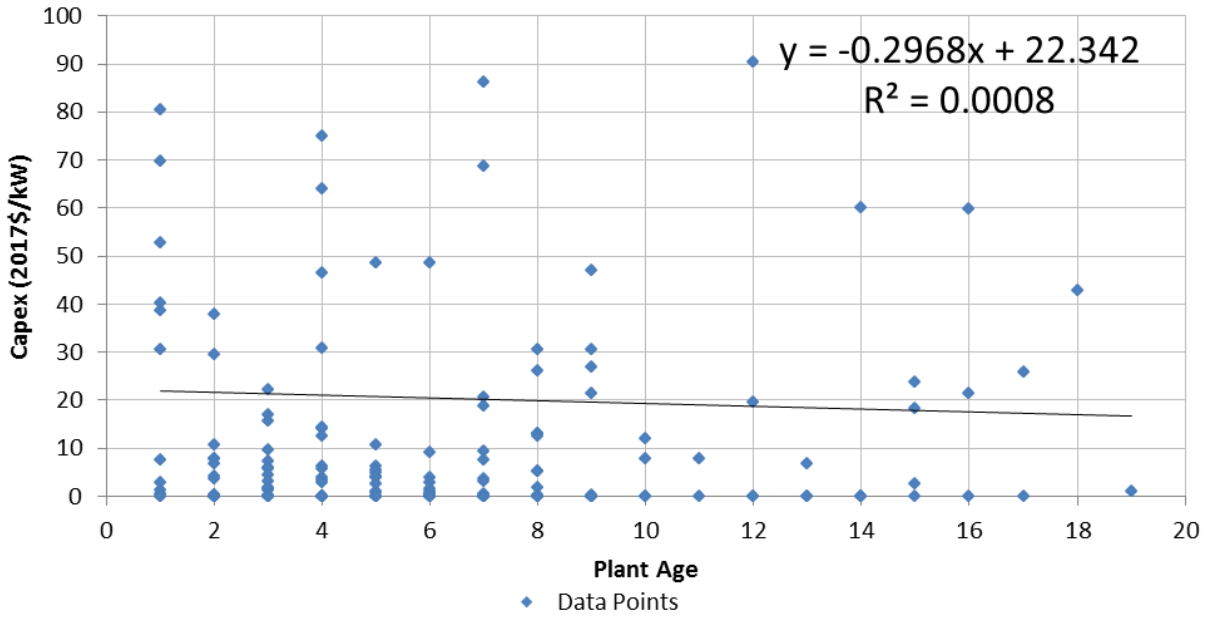
0-100 MW

The results of the linear regression analysis of CAPEX spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.706, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, a more appropriate predictor of CAPEX spending for this dataset is a simple average by plant age band, as discussed in Section 12.

Table J-3 — Regression Statistics – Wind CAPEX for 0-100 MW

		t Statistic	*p-value*
Observations	174		
Simple Average ($/kW)	20.483		
Intercept	22.342	3.7750	2.20E-04
Slope	-0.297	-0.3779	7.06E-01
R^2	0.00083		

Figure J-2 — Wind Dataset – CAPEX for 0-100-MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table J-4 — Wind < 100-MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (Years 11-15)	Average $/kW-yr (Years 16-20)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (All Years)
< 100 MW, All Capacity Factors										
Net Total CAPEX – 2017 $/kW-yr	22.83	11.62	35.35	21.60	**20.48**	89	58	20	7	**174**

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

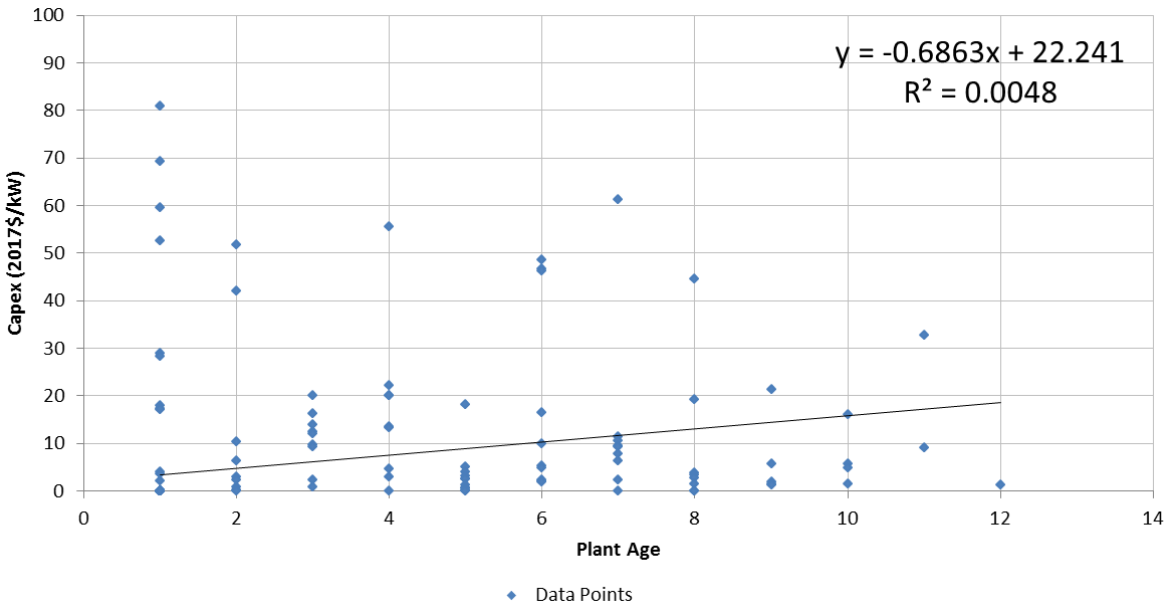
100-200 MW

The results of the linear regression analysis of CAPEX spending for wind plants between 100 MW and 200 MW are summarized in the table below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table J-5 — Regression Statistics – Wind CAPEX for 100-200 MW

		t Statistic	*p-value*
Observations	310		
Simple Average ($/kW)	16.935		
Intercept	22.241	5.7807	1.82E-08
Slope	-0.686	-1.2194	2.24E-01
R^2	0.00480		

Figure J-3 — Wind Dataset – CAPEX for 100-200-MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table J-6 — Wind 100-200-MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (Years 11-15)	Average $/kW-yr (Years 16-20)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (All Years)
100 - 200 MW, All Capacity Factors										
Net Total CAPEX – 2017 $/kW-yr	20.36	12.20	14.41	--	**16.93**	52	36	3	--	**91**

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

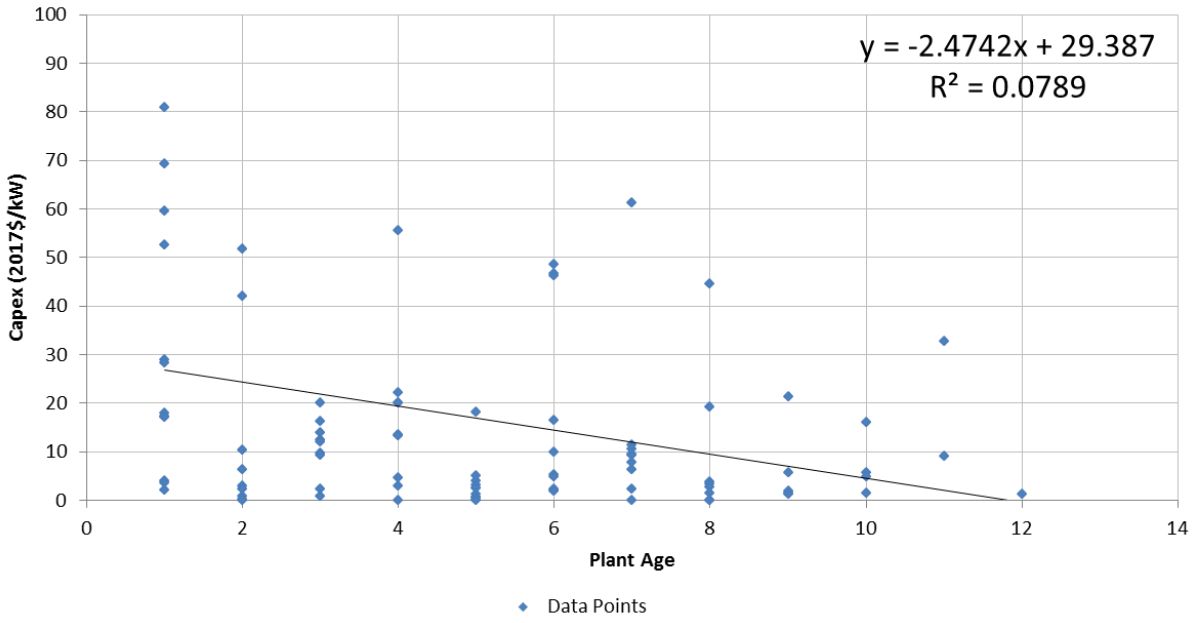
Greater than 200 MW

The results of the linear regression analysis of CAPEX spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.006, which is less than 0.05, the dataset does support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, a visual inspection of the data in the graph below shows that there are a limited number of data points over 10 years, which may be skewing the regression.

Table J-7 — Regression Statistics – Wind CAPEX for Greater than 200 MW

		t Statistic	*p-value*
Observations	91		
Simple Average ($/kW)	16.935		
Intercept	29.387	5.6538	1.87E-07
Slope	-2.474	-2.7612	6.99E-03
R^2	0.07891		

Figure J-4 — Wind Dataset – CAPEX for Greater than 200-MW Plant Sizes



The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

Table J-8 — Wind Greater than 200-MW Summary of Results

	Average $/kW-yr (Years 1-5)	Average $/kW-yr (Years 6-10)	Average $/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (All Years)
> 200 MW, All Capacity Factors						
Net Total CAPEX – 2017 $/kW-yr	**16.61**	**8.65**	**13.48**	31	20	**51**

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

OPERATIONS & MAINTENANCE EXPENDITURES

Full Dataset

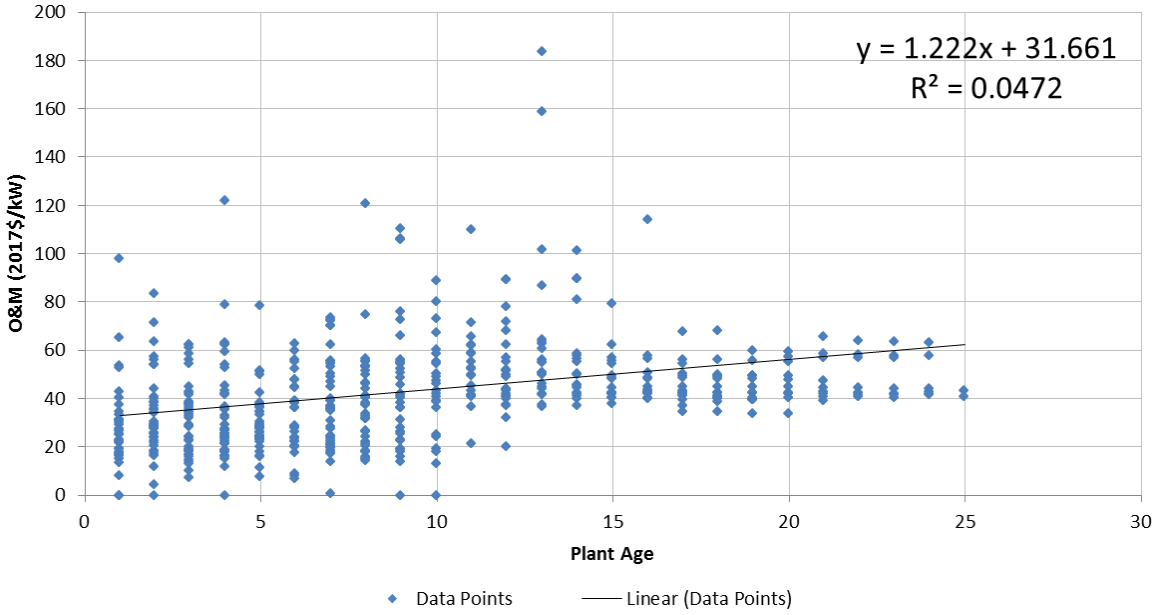
The results of the linear regression analysis of O&M spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 31.661 + (1.222 × age)

Table J-9 — Regression Statistics – Wind O&M for All MW

		t statistic	*p-value*
Observations	580		
Simple Average ($/kW)	42.680		
Intercept	31.661	12.7763	4.24E-33
Slope	1.222	5.3515	1.26E-07
R^2	0.04721		

Figure J-5 — Wind Dataset – O&M for All MW Plant Sizes



0-100 MW

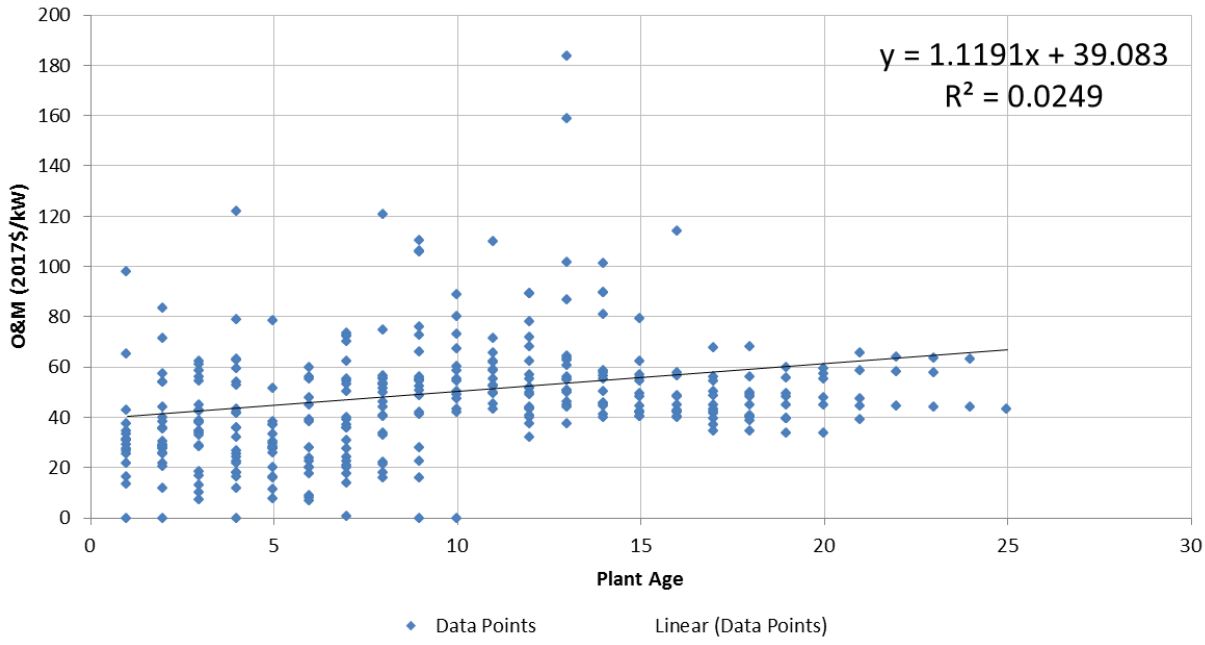
The results of the linear regression analysis of O&M spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.003, which is less than 0.05, the dataset age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 39.083 + (1.119 × age)

Table J-10 — Regression Statistics – Wind O&M for 0-100 MW

		t Statistic	*p-value*
Observations	339		
Simple Average ($/kW)	49.888		
Intercept	39.083	9.0574	1.10E-17
Slope	1.119	2.9310	3.61E-03
R^2	0.02486		

Figure J-6 — Wind Dataset – O&M for 0-100-MW Plant Sizes



100-200 MW

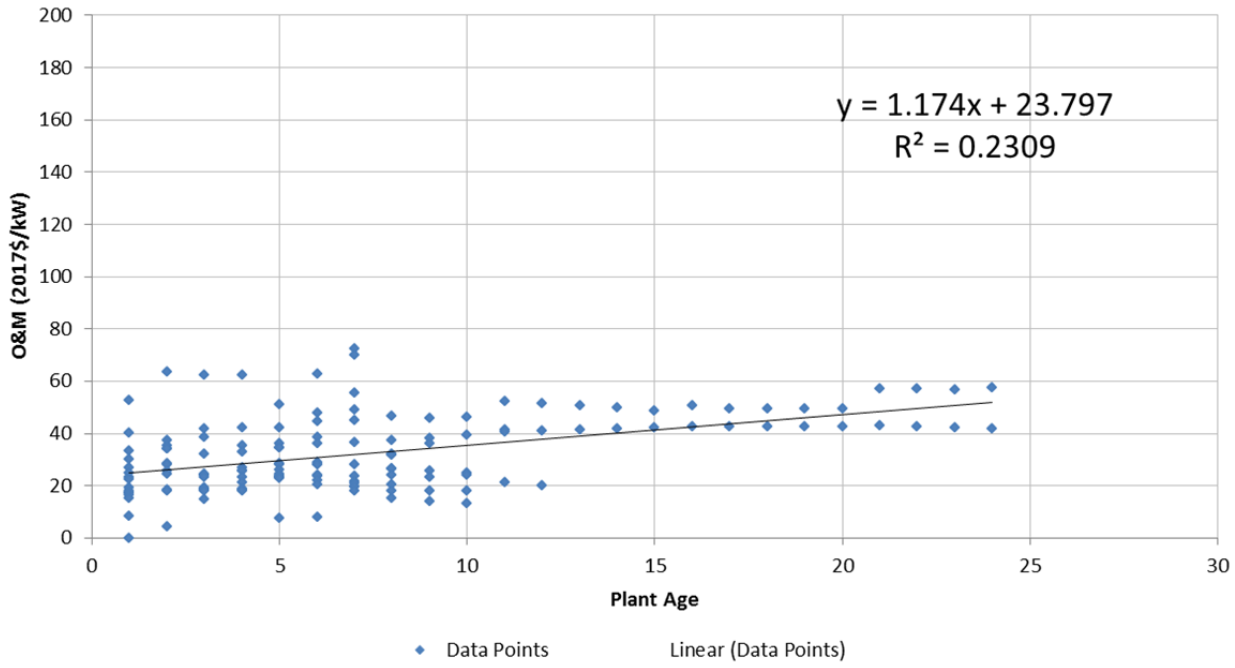
The results of the linear regression analysis of O&M spending for wind plants between 100 MW and 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 23.797 + (1.174 × age)

Table J-11 — Regression Statistics – Wind O&M for 100-200 MW

		t Statistic	*p-value*
Observations	147		
Simple Average ($/kW)	35.645		
Intercept	23.797	14.1919	3.27E-29
Slope	1.174	6.5971	7.33E-10
R^2	0.23086		

Figure J-7 — Wind Dataset – O&M for 100-200-MW Plant Sizes



Greater than 200 MW

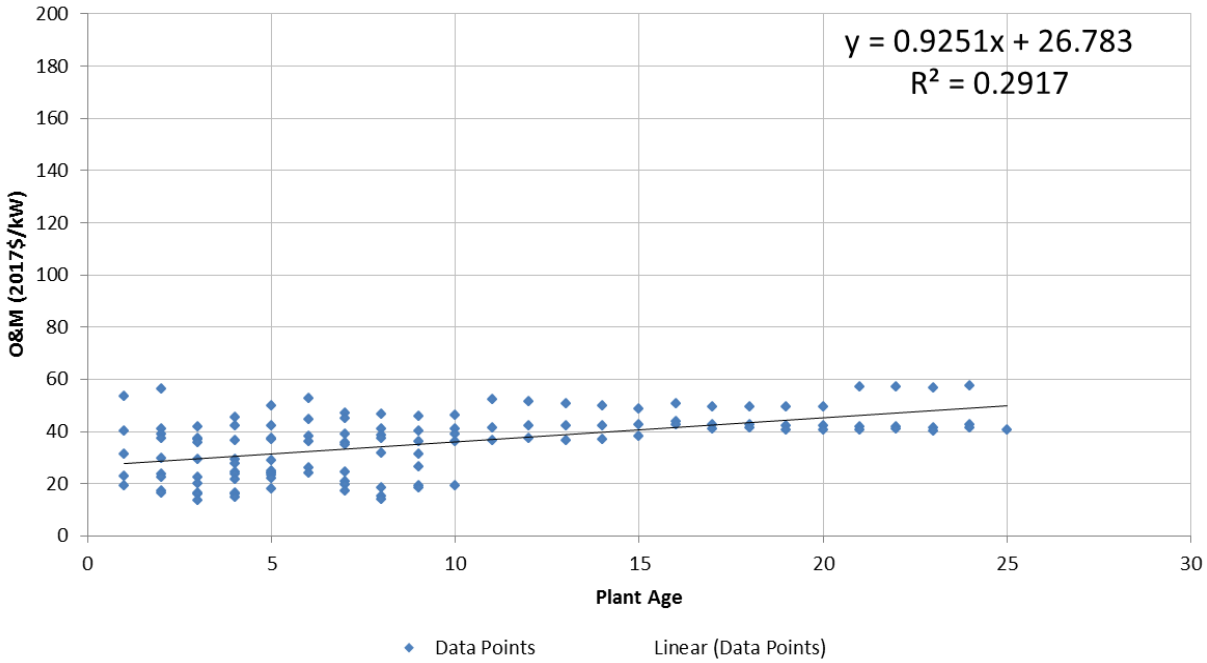
The results of the linear regression analysis of O&M spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

Annual O&M spending in 2017 $/kW-year = 26.783 + (0.925 × age)

Table J-12 — Regression Statistics – Wind O&M Greater than 200 MW

		t statistic	*p-value*
Observations	124		
Simple Average ($/kW)	35.645		
Intercept	26.783	17.5334	3.90E-35
Slope	0.925	7.0885	9.55E-11
R^2	0.29171		

Figure J-8 — Wind Dataset – O&M for Plant Sizes Greater than 200 MW



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-163
Trump Advisor Says Electricity Customers Pay for 202(c) Orders

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The J.H. Campbell coal-fired power plant in Michigan. Consumers Energy had planned to retire the plant in 2025, but President Trump ordered it to keep operating.
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A Trump administration official said Wednesday that efforts to keep coal-fired power plants running beyond their planned retirement dates will ultimately be paid for by electricity customers.

Federal efforts to block coal plant retirements aim to preserve grid reliability amid a surge in electricity demand driven by data centers and artificial intelligence, said Peter Lake, a member of the White House's National Energy Dominance Council, speaking at the American Enterprise Institute's "Powering Prosperity and the New Electricity Economy" conference in Washington.


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"All costs end up on ratepayers," Lake said, responding to a question about who pays when utilities are required by the federal government to keep coal plants online after having invested billions of dollars in replacement power generation.

He added that industrial customers typically bear a larger share of those costs, equivalent to about 60%. But it depends on the utility, their generation makeup, and how rate structures allocate expenses based on load size and peak demand.

The Trump administration has so far prevented dozens of coal units from retiring, invoking emergency authorities and directing federal agencies to intervene in power markets. Officials say the U.S. grid cannot afford to lose generation as electricity demand accelerates faster than expected.

The administration has also framed its coal policy as an affordability and reliability measure, aimed at avoiding what Lake said could be $34 billion to $40 billion in replacement costs if operating coal plants were allowed to retire before new dispatcheable resources are in place.

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Government estimates call for roughly 100 gigawatts of new power by 2030, a figure Lake compared with adding “California plus two New Yorks” to the grid in less than five years.

“Yes, we need coal. We need gas. We need batteries. Anything with an answer,” Lake said.

Coal is getting a boost from AI power and industrial demand. Several utilities, including Duke Energy and some subsidiaries of Southern Company, revised plans to retire some coal units after forecasting sharp increases in demand from data centers and advanced manufacturing. The changes were approved through state-regulated processes.

But utilities say that being forced to keep some coal plants open is upending years of state-approved planning.

For example, the Michigan-based Campbell coal plant, owned by CMS Energy, was forced by the Trump administration to continue operating into 2026 after being scheduled to retire in 2025, costing about $615,000 a day, according to company filings. The state utility running the plant, Consumers Energy, had already invested in replacement gas generation, renewable contracts, and grid upgrades.

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Consumers Energy warned that extending Campbell’s operations will adds millions of dollars in incremental fuel, maintenance, and staffing costs that weren’t contemplated in approved rates, according to regulatory filings.

Consumers in regulated energy markets may be hit hardest as coal plants stay open longer than planned. A utility that voluntarily plans to delay a plant retirement often gets approval from regulators in a deal that includes freezing rates for consumers and special tariffs that shift costs toward large industrial users like data centers.

That framework can collapse when Washington forces plants to keep operating. When a plant is kept online after replacement assets are already in the rate base, customers effectively pay twice—once for the new plant, and again for the old one.

Some utilities are trying to manage rising AI power needs without passing along costs to households. In Louisiana and parts of the Midwest, for instance, utilities have negotiated special large-load tariffs and contract terms with data-center customers that include higher base rates, upfront infrastructure contributions, and curtailment provisions during grid stress.



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Still, some energy experts say the administration's plans to delay coal retirements may be counterproductive and obscure the more pressing problem: permitting delays to upgrade the grid.

"Mandating that an old power plant operate isn't consistent with a market-based approach," said Rob Gramlich, president of Grid Strategies LLC, at the AEI conference, noting that tens of gigawatts of approved generation remain stalled in interconnection queues due to permitting and transmission constraints.

A study by Grid Strategies, a consultancy funded partly by environmental groups including the Sierra Club, found that the administration's plan to stop fossil fuel plants from closing could cost ratepayers $3.1 to $5.9 billion a year.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-164
Colorado Commission Decision No. C24-0052

Decision No. C24-0052

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0141E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN.

PHASE II DECISION: (1) ADDRESSING RESOURCE SELECTION AND THEREBY MODIFYING PUBLIC SERVICE'S CLEAN ENERGY PLAN; (2) ADDRESSING THE ADDITIONAL TRANSMISSION INVESTMENTS IDENTIFIED IN PHASE II; (3) ESTABLISHING PERFORMANCE INCENTIVE MECHANISMS FOR UTILITY-OWNED GENERATION; (4) ADDRESSING THE 2024 JUST TRANSITION SOLICITATION; AND (5) ADDRESSING RELATED MATTERS

Mailed Date: January 23, 2024
Adopted Date: December 6, 13, 20, 2023

TABLE OF CONTENTS

I. BY THE COMMISSION 3
A. Statement 3
B. Discussion 7
1. Electric Resource Planning 7
2. Clean Energy Plans Pursuant to SB 19-236 9
3. Procedural Background 13
C. Phase I Decision and Public Service CEP 18
D. Phase II Filings 19
1. 120-Day Report 19
2. CDPHE Verification 21
3. IE Report 22
4. Intervenor Comments 22
5. Comments from the Northern Cheyenne Nation 24
6. Public Comments 24
7. Public Service's Response Comments and the UPP 25
E. Modification of the CEP's Resource Portfolio 27

Colorado PUC E-Filings System

1. Emission Reductions 34
2. Reasonable Cost to Customers 38
3. Reliability and resilience of the electric system 45
4. Future Technology Development 50
5. Transmission Concerns 54
6. Conclusion 57
F. Transmission 58
1. Phase II Changes in Transmission Investments 58
2. Party Comments 60
3. Findings and Conclusions regarding Transmission 63
G. Performance Incentive Mechanisms 69
1. Background and Party Comments 69
2. Findings and Conclusions 72
H. The Sand Creek Massacre National Historic Site and Bid 1029 80
I. Hayden Biomass 83
1. Party Comments 84
2. Findings and Conclusions 87
J. Backup Bids 90
1. Party Comments 90
2. Findings and Conclusions 93
K. Section 123 Resources 95
L. Prospective New Load 97
M. Clean Energy Plan Rider (CEPR) 99
1. Public Service's New CEPR Proposals and Party Comments 100
2. Findings and Conclusions 102
N. Best Value Employment Metrics 103
O. In Service Date Extensions 107
P. Repricing 108
Q. 2024 Just Transition Solicitation 109
1. Modeling Improvements 109
2. Non-Negotiable PPA Terms 113
3. Company Ownership 115
4. Just Transition Bids 116
5. Discount Rates 118

6. Comprehensive Rate Analysis 118
R. Miscellaneous Issues for Future Proceedings 119
1. Equity Directives 119
2. CPCN Prioritization 121
3. Voluntary Additional Emissions Reduction Program 123
S. Requests not Explicitly Addressed 125
II. ORDER 125
A. The Commission Orders That: 125
B. ADOPTED IN COMMISSIONERS' WEEKLY MEETINGS December 6, 13, and 20, 2023. 127

I. BY THE COMMISSION

A. Statement

1. In accordance with § 40-2-125.5(4), C.R.S., the electric resource plan (ERP) filed by Public Service Company of Colorado (Public Service or the Company) on March 31, 2021, includes a Clean Energy Plan (CEP) to reduce the Company's carbon dioxide (CO2) emissions by a target of 80 percent by 2030 as compared to 2005 levels. As set out in Decision No. C22-0459 (the Phase I Decision)[1] and Decision No. C22-0559 (addressing applications for rehearing, reargument, or reconsideration)[2] the Commission approved certain elements of the Company's CEP, including the Coal Action Plan that transitions Public Service away from its remaining coal facilities. The Commission also authorized Public Service to use Phase II of this Proceeding to further implement the requirements for approval of a CEP such that the Commission could continue evaluation of, among other things, the additional clean energy plan activities, the actions and investments projected to achieve compliance with the clean energy targets in § 40-2-125.5(3)(a)(I) and (3)(a)(II), and whether the CEP is in the public interest and consistent

[1] Issued August 3, 2022.
[2] Issued September 21, 2022.

with the clean energy target in § 40-2-125.5(3)(a)(I). The Commission's decisions in Phase I and Phase II of this ERP proceeding thus implement a bold clean energy policy that helps avoid the worst impacts of climate change while allowing Coloradoans to enjoy the benefits of reliable clean energy at an affordable cost.

2. Throughout the course of Phase II, Public Service showcased its preferred resource portfolio of new utility resources to be acquired through 2027 and, in response to party and public comments, its updated preferred portfolio of resources. In accordance with the Commission's Phase I directives, the Company also presented numerous alternate portfolios for consideration. Although the Company's preferred resource portfolio[3] projects sufficient emission reductions to exceed statutory requirements, comments point out that not only might these projected reductions in emissions be overstated, but that the costs to customers would be significant – pointing to, among other major concerns, billions of dollars in modeled transmission investment changes between Phase I and II, and significant utility ownership in gas resources presented in the Company's updated preferred plan.

3. Building on our determinations in Phase I, we find that modifying the Company's CEP by selecting an alternative resource portfolio (the Alternative Portfolio)[4] is necessary considering statutory and public interest concerns.

4. The Alternative Portfolio exceeds Colorado's goals in emission reductions and protects reliability of the electrical system, according to the Company's analysis. At the same time,

[3] As detailed below, in the 120-Day Report, Public Service presented its Preferred Portfolio, and this Preferred Portfolio is what comments from intervenors address. In its Response Comments, the Company presents an Updated Preferred Portfolio. Apart from a few minor modifications (*e.g.* replacing a wind project with a different wind project) the Updated Preferred Portfolio and the Preferred Portfolio are identical. The benefits of the Alternative Portfolio set forth throughout this Phase II decision apply both to the Preferred Portfolio and the Updated Preferred Portfolio.

[4] As discussed below, the Alternative Portfolio is the Inverse 1324 ($0CO2) Plan that Public Service included in the 120-Day Report. (*See* 120-Day Report (Appendix S) Rev. 1, p. 26).

the Alternative Portfolio—which includes fewer new utility-owned resources than the Company's preferred resource portfolio and is thus better tailored to the developing capabilities of the Company's system—will reduce costs to customers, especially considering factors such as the curtailment of generated renewable energy.

5. This case propels Colorado's transition towards greater reliance on renewable resources, takes massive strides towards emission reductions, and continues on a path towards 100 percent clean energy resources; however, the Company maintains that system reliability currently requires at least some new natural gas-fired generation resources. Like the Company's updated preferred portfolio, the Alternative Portfolio includes nearly half the amount of gas resources predicted in the Phase I Settlement modeling, which was supported by a majority of parties with diverse interests, including some environmental advocates.[5] Moreover, and unlike the Company's updated preferred plan, the Alternative Portfolio better allows for technological advancements and flexibility by deferring certain resource acquisitions, reducing the amount of Company-owned gas resources, and significantly increasing the amount of storage on the electrical system. For similar reasons, the Alternative Portfolio creates the opportunity to better optimize transmission upgrades during resource procurement in future proceedings.

6. Particularly given the billions of dollars in discrepancies of modeled transmission costs, granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio with the Phase I authorizations also allows us to better support Colorado customers and communities. Through directed modeling and filing considerations, we include further direction to support transitioning communities through the 2024 Just Transition Solicitation. As we remain dedicated to supporting the economic changes facing our state's

[5] Phase I Settlement (Attachment D), p. 2.

transitioning communities, optionality and opportunity through ongoing, robust, competitive bidding is essential to continue selecting optimal resources to support Colorado's needs. In recognition that affordability of energy bills remains a significant focus, we also include direction on performance incentive mechanisms that further incentivize Public Service to reduce the costs of the new Company-owned generation and promotes fairness and transparency within the competitive bidding process.

7. On balance, the Phase I and Phase II Decisions together provide a measured approach to reliability and cost considerations, while taking exponential strides towards a clean energy future that supports Colorado citizens. These decisions propel the Company towards an 86 percent reduction in emissions by 2030 as well as the goal of providing its customers with energy from 100 percent clean energy resources by 2050.

8. Thus, through this Decision we find that modification of the proposed CEP to include the Alternative Portfolio is necessary to ensure the CEP is in the public interest. Consistent with the Phase I Decision and determinations in this Phase II order, we direct Public Service to pursue this modified CEP and its Alternative Portfolio of resources with further due diligence and contract negotiations and to file applications for Certificates of Public Convenience and Necessity (CPCNs) for all Company-owned generation resources arising from the modified CEP. We further direct that all Company-owned generation resources arising from the modified CEP are subject to both the cost to construct performance incentive mechanism (PIM) and the operational PIM set forth below.

9. In addition, we make several directives regarding transmission investments as well as future proceedings, including the 2024 Just Transition Solicitation proceeding and the

application Public Service will file regarding the attribution of costs between the CEP rider (CEPR) and the Renewable Energy Standard Adjustment (RESA).

B. Discussion

1. Electric Resource Planning

10. The Commission's ERP Rules, set forth at 4 *Code of Colorado Regulations* (CCR) 723-3-3600, *et seq*., serve two primary functions. First, the rules require a regular, periodic examination of an electric utility's energy sales and demand forecasts as compared to an assessment of its existing resources to ensure that sufficient generation will be available to meet customer needs in the future. Second, the Commission's review and approval of an ERP ensures that the utility acquires a cost-effective mix of additional resources consistent with the state's public policy objectives.

11. As established in the ERP Rules, for decades Colorado electric utilities have used competitive bidding to procure additional resources to meet identified future resource needs. An ERP thus describes in detail how the utility will evaluate the bids and proposals submitted in response to Requests for Proposals (RFPs), including the inputs and assumptions to its bid evaluation models (*e.g.*, natural gas prices, the social costs of emissions, discount rates, etc.), and how it will apply resource selection criteria.

12. The ERP process includes two phases. In Phase I, the Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources.[6] In Phase II, the Commission issues a final decision regarding the utility's preferred cost-effective plan for pursuing the acquisition of particular resources.

[6] Rule 4 CCR 723-3-3617(c) describes the contents of the Commission's Phase I decision in more detail.

13. Phase II begins after the Commission issues its Phase I decision. Public Service issues its RFPs, receives competitive bids and utility-owned proposals, and files a report no later than 120 days after the bids are received in accordance with Rule 4 CCR 723-3-3613(d) (120-Day Report). The 120-Day Report presents an evaluation of all proposed resources, based on the criteria established in the Phase I decision (*e.g.*, the base modeling inputs and assumptions to be used in developing optimized resource portfolios and the sensitivities that "re-price" optimized portfolios using alternative values for selected inputs and assumptions).

14. At the end of Phase II, the Commission issues a final decision that approves, conditions, modifies, or rejects the utility's preferred cost-effective resource plan. Rule 3613(h) describes the contents of a Phase II decision as follows:

> Within 90 days after the receipt of the utility's 120-day report under paragraph 3613(d), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan. The utility shall pursue the final cost-effective resource plan either with a due diligence review and contract negotiations, or with applications for CPCNs (other than those CPCNs provided in paragraph 3611(e)), as necessary. In rendering the decision on the final cost-effective resource plan, the Commission shall weigh the public interest benefits of competitively bid resources provided by other utilities and non-utilities as well as the public interest benefits of resources owned by the utility as rate base investments. In accordance with §§ 40-2-123, 40-2-124, 40-2-129, and 40-3.2-104, C.R.S, the Commission shall also consider renewable energy resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that affect employment and the long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

15. Upon the conclusion of Phase II, and consistent with Rule 3613(h), upon the issuance of this Phase II Decision, Public Service will continue its due diligence and contract negotiations, as appropriate, and file applications for CPCNs in accordance with § 40-5-101, C.R.S., for each of the Company-owned projects arising from approval of the modified CEP.

These projects will be entitled to a presumption of prudence per Rule 3617(d), supported primarily through the determinations of need in Phase I and Phase II, the use of competitive bidding, and the implementation of bid evaluation and selection pursuant to our Phase I decision. Given the magnitude of this ERP Proceeding and the complexity associated with the CEP considerations set forth below, the Commission waives the 90-day deadline to issue a Phase II decision as contemplated by Rule 3613(h).

2. Clean Energy Plans Pursuant to SB 19-236

16. While longstanding statutes, the Commission's rules, and competitive bidding processes are foundational to the Colorado's utility resource planning process, recent legislative changes, including Senate Bill (SB) 19-236 further overlay CEP considerations on Public Service's current ERP.

17. SB 19-236 enacts § 40-2-125.5(1) that declares the statewide importance of promoting cost-effective clean energy and new technologies and reduction of carbon dioxide emissions from the Colorado electric generating system and includes that "[a] bold clean energy policy will support this progress and allow Coloradans to enjoy the benefits of reliable clean energy at an affordable cost." Specifically, § 40-2-125.5(3) requires that, in addition to the other requirements of the section, Public Service shall meet the following clean energy targets:

> (I) By 2030, the qualifying retail utility shall reduce the carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels; and
>
> (II) For the years 2050 and thereafter, or sooner if practicable, the qualifying retail utility shall seek to achieve the goal of providing its customers with energy generation from one-hundred-percent clean energy resources so long as doing so is technically and economically feasible, in the public interest and consistent with the requirements of this section.

18. The statute further requires that the first ERP following January 1, 2020, must include a CEP that "will achieve the clean energy target set forth in subsection (3)(a)(I)" and will "make progress toward the [100 percent] clean energy goal set forth in subsection (3)(a)(II)."[7] Subsection 4 further specifies what a CEP must include (*e.g.*, a plan of actions and investments projected to achieve compliance with the clean energy targets set forth in subsection (3)(a)(I) and (3)(a)(II), the projected costs of the CEP's implementation, and workforce transition and community assistance plans).

19. Subsection 4(d) includes that the Commission "shall approve the [CEP] if the commission finds it to be in the public interest and consistent with the [80 percent target], and the commission may modify the plan if the modification is necessary to ensure the plan is in the public interest." In evaluating whether a CEP submitted is in the public interest, the Commission is directed to consider the following factors, "among other relevant factors as defined by the commission":

> (I) Reduction in carbon dioxide and other emissions that will be achieved through the clean energy plan and the environmental and health benefits of those reductions;
>
> (II) The feasibility of the [CEP's] impact on the reliability and resilience of the electric system. The commission shall not approve a plan that does not protect system reliability.
>
> (III) Whether the [CEP] will result in a reasonable cost to customers, as evaluated on a net present value basis.[8]

20. If the Commission approves a CEP that achieves an emission reduction of at least 75 percent from 2005 levels, then the relevant utility is provided with a "safe harbor" from any

[7] § 40-2-125.5(4)(a).
[8] § 40-2-125.5(4)(d)(III).

additional emission reduction regulations that the Air Quality Control Commission (AQCC) might develop for the power sector through 2030.[9]

21. As a general matter, the Colorado Department of Public Health and Environment (CDPHE) is tasked with calculating whether a proposed CEP will meet these clean energy targets. In particular, the division of administration in the CDPHE must describe the methods of measuring CO2 emissions and verify the projected CO2 emission reductions of the CEP.[10] The statute goes on to state that the division of administration, in consultation with the AQCC, must determine whether the CEP will meet the 2030 clean energy targets, and will report to the Commission the division's calculation of CO2 emission reductions attributable to any approved CEP.[11]

22. SB 19-236 also sets forth accounting requirements to track the costs of the CEP. For instance, § 40-2-125.5(4)(a)(III) states the utility must "clearly distinguish" between the set of resources necessary to meet customer demands in the resource acquisition period (RAP) and the additional CEP activities—such as the retirement of existing generating facilities—that may be undertaken to meet the clean energy target of 80 percent emission reduction by 2030. Moreover, the CEP must set forth the projected cost of its implementation and anticipated reductions in carbon dioxide and other emissions.[12] Likewise, the CEP must list the "actions and investments" necessary to meet the clean energy target and describe the effect of such actions and investments on the safety, reliability, renewable energy integration, and resiliency of the electric system.[13]

23. The statute goes on to direct the utility to collect revenues for the additional CEP activities through a CEPR assessed on a percentage basis on all retail customer bills.[14] This CEPR

[9] § 25-7-105(1)(e)(VIII)(C), C.R.S.
[10] § 40-2-125.5(4)(b).
[11] § 40-2-125.5(4)(c)(1).
[12] § 40-2-125.5(4)(a)(VI)
[13] § 40-2-125.5(4)(a)(IV)—(V).
[14] § 40-2-125.5(5)(a)(II)

is limited to a maximum electric retail rate impact of 1.5 percent of the total annual electric bill for each customer for implementation of the approved additional clean energy plan activities and "may be established as early as the year following approval of a clean energy plan by the commission."[15]

24. SB 19-236 requires that the ERP containing the CEP use a RAP extending through 2030. If the CEP calls for the accelerated retirement of any generating facilities, the CEP must include a workforce transition plan for impacted utility workers. Similarly, the CEP must include a plan to pay community assistance to any local government or school district whose voters previously approved projects, the costs of which are expected to be paid for from property taxes that the accelerated retirement directly impacts.[16]

25. While the statute requires the utility to use a competitive bidding process to procure any energy resources to fill the cumulative resource need derived from the ERP and CEP, the Commission shall also allow the utility to own a target of 50 percent of the energy and capacity developed or acquired to meet the resource need "if the commission finds the cost of utility or affiliate ownership of the generation assets comes at a reasonable cost and rate impact."[17]

26. As discussed in our Phase I Decision, several of the statutory findings required for an approved CEP could not be made in the Phase I Decision but must wait until Phase II. For instance, the actions and investments required to fill the additional resource need for the CEP, the projected cost to implement the CEP, and the cost and rate impact of the 50 percent utility ownership target could not be known until after the 120-Day Report. The Phase I Decision permitted Public Service to issue the RFP and proceed to Phase II and established the framework in which bids will be evaluated and selected, setting important Phase II assumptions regarding the

[15] § 40-2-125.5(5)(a)(I).
[16] § 40-2-125.5(4)(a)(VII).
[17] § 40-2-125.5(5)(b).

treatment of the Company's remaining coal-fired power plants, and ensuring that the 120-Day Report contains the information required to make the statutory findings necessary to reach an approved CEP.

27. The Commission did not anticipate, and no party requested, a fully litigated hearing in Phase II.[18] Rather, through its usual Phase II process, the Commission can address the necessary statutory findings in this Phase II Decision (*e.g.*, upon consideration of the 120-Day Report, the parties' comments to the 120-Day Report, and the IE Report). As the parties assert in their Joint Brief Addressing Phase II Topics, (filed on August 2, 2021) SB 19-236 might change the objectives of the ERP process, but it does not direct any changes to the process itself.[19]

3. Procedural Background

28. A complete procedural history through Phase I of this Proceeding is provided in the Phase I Decision.

29. The parties in this Proceeding consist of the following: Public Service; Staff of the Colorado Public Utilities Commission (Staff); the Office of Utility Consumer Advocate (UCA); the Colorado Energy Office (CEO); the City of Boulder (Boulder); the Colorado Energy Consumers (CEC); Climax Molybdenum Company (Climax); Colorado Independent Energy Association (CIEA); Interwest Energy Alliance (Interwest); Colorado Solar and Storage Association and Solar Energy Industries Association (jointly COSSA/SEIA); the International Brotherhood of Electrical Workers, Local No. 111 (Local 111); Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (jointly,

[18] This is consistent with the position of the parties. (Joint Brief Addressing Phase II Topics, p. 8 (arguing that the statutory findings required to approve a CEP do not necessitate a Phase II hearing)).

[19] Joint Brief Addressing Phase II Topics, p. 13.

RMELC and CBCTC);[20] Holy Cross Electric Association, Inc. (Holy Cross); CORE Electric Cooperative (CORE); Western Resource Advocates (WRA); Vote Solar; Walmart Inc. (Walmart); Colorado Renewable Energy Society (CRES); Natural Resources Defense Council and Sierra Club (collectively, the Conservation Coalition); the City and County of Denver (Denver); the Board of County Commissioners of Pueblo County (Pueblo County); the City of Pueblo and Board of Water Works of Pueblo (jointly Pueblo City and Water); Onward Energy Management (Onward); and the Colorado Oil and Gas Association (COGA). The Commission also granted Black Hills Colorado Electric, LLC (Black Hills) leave to participate as an *amicus curiae* in this Proceeding.[21]

30. In addition, in Decision No. C21-0343-I,[22] the Commission granted the Unopposed Motion for Limited Participation that CDPHE filed on April 29, 2021. As such, CDPHE is participating in this Proceeding as a neutral verifier.

31. In response to Decision No. C21-0404-I,[23] in which the Commission solicited briefs from the parties regarding Phase II procedures, on August 2, 2021, Public Service, Staff, UCA, CEO, CIEA, COSSA/SEIA, RMELC and CBCTC, Local 111, Conservation Coalition, Interwest, Onward, Pueblo County, Pueblo City and Water, Walmart, and WRA jointly filed a brief arguing that no Phase II hearing is required. Vote Solar was the only party to file a separate Phase II brief, in which it states that it "does not believe Senate Bill 19-236 requires a Phase II hearing" but argues that "additional evidentiary hearing process may nonetheless be necessary in Phase II if Public Service Company of Colorado proposes any portfolios in its 120-Day Report that include gas plants located in, or near, any disproportionately impacted communities."[24]

[20] Local 111, RMELC, and CBCTC collectively refer to themselves as the Labor Interests.
[21] The Commission denied the Motions to Intervene filed by Ms. Leslie Glustrom and the Coalition of Ratepayers. (Decision No. C21-0315-I, pp. 16-22.)
[22] Issued June 9, 2021.
[23] Issued June 23, 2021.
[24] Vote Solar's Phase II Brief, p. 1.

32. On September 30, 2021, the Office of Just Transition (OJT) filed a motion to intervene out of time, or in the alternative, to participate as *amicus curiae*. On October 25, 2021, the Commission granted OJT's motion to intervene out of time, allowing OJT to participate as a party in this Proceeding.[25]

33. On August 3, 2022, the Commission issued the Phase I Decision addressing Public Service's ERP and CEP and approving, in part, the Updated Non-unanimous Partial Settlement Agreement (Phase I Settlement) filed on April 26, 2022.[26] Among other things, the Phase I Decision directed Public Service to issue RFPs for an all-source, competitive bidding process to meet its resource need.

34. On September 21, 2022, the Commission issued Decision No. C22-0559 addressing applications for rehearing, reargument, or reconsideration of the Phase I Decision.

35. On December 1, 2022, Public Service issued its 2022 All-Source RFPs.

36. On March 31, 2023, Public Service filed its "30-Day Report" describing bids received in response to its competitive bid solicitation.

37. On March 31, 2023, Public Service filed an unopposed motion to, among other things, extend by 50 days the time to file the 120-Day Report. By Decision No. C23-0246-I,[27] the Commission granted the Company's motion and extended the deadline for the 120-Day Report as well as all associated deadlines.

[25] Decision No. C21-0666-I, issued October 20, 2021.

[26] The Phase I Settlement was supported by the following parties: Public Service, Staff, UCA, CEO, RMELC and CBCTC, COSSA/SEIA, Pueblo County, Holy Cross, Pueblo City and Water, Walmart, Boulder, Denver, COGA, Local 111, the OJT, CIEA, Onward, Interwest, Conservation Coalition, and WRA.

[27] Issued on April 13, 2023.

38. On July 27, 2023, Public Service filed the Motion for Second Extension requesting an additional 24-day extension of time within which to file the 120-Day Report. By Decision No. C23-0522-I,[28] the Commission granted the Motion for Second Extension.

39. On September 5, 2023, Public Service together with the Independent Evaluator (IE) and Staff filed a Motion that requested a third extension of time for the Phase II deadlines. On September 5, 2023, various parties representing the interests of independent power producers (IPPs) filed a Response to the Joint Motion for Third Extension (Joint IPP Interests Response). The Joint IPP Interests Response was specifically filed by COSSA/SEIA, CIEA, and Interwest. These parties argued that the IPP projects will be prejudiced by the additional requested delay, which could postpone final decisions in this matter through March of 2023 to consider requests for rehearing, reargument, and reconsideration. By Decision No. C23-0594-I[29] and Decision No. C23-0647-I,[30] the Commission granted, in part, and denied, in part, the requested Phase II extensions. While the Commission recognized the significant complexity of this Phase II process relative to past ERPs, it agreed with other parties regarding the urgency of issuing a Phase II decision.

40. Ultimately, the Company filed the 120-Day Report on September 18, 2023, approximately 80 days after the Company was initially scheduled to file the 120-Day Report.[31] Public Service would subsequently file corrections to the 120-Day Report on October 18, 2023.

[28] Issued on August 8, 2023.
[29] Issued September 7, 2023.
[30] Issued September 27, 2023.
[31] The original deadline for the 120-Day Report was June 29, 2023. (Decision No. C23-0246-I, ¶ 4).

41. On October 5, 2023, the Commission issued Decision No. C23-0672-I, that required the Company, and invited other parties, to submit comments outlining a potential risk sharing mechanism for Company-owned generation.

42. On October 18, 2023, the Air Pollution Control Division of the CDPHE filed the Phase II Clean Energy Plan Verification Report.

43. On October 20, 2023, in response to Decision No. C23-0672-I, Public Service submitted a proposal for risk-sharing mechanisms regarding Company-owned generation resources. Staff similarly filed a proposal on October 20, 2023, which UCA and CEC joined.

44. On October 21, 2023, the IE filed its report (the IE Report).

45. On November 8, 2023, intervenor comments on the 120-Day Report were filed.

46. On November 20, 2023, Public Service filed its Response Comments to the 120-Day Report.

47. On December 6 and 13, 2023, the Commission commenced deliberations. On December 13, 2023, the Commission also issued Decision No. C23-0841-I, directing Public Service to set forth certain information related to the cost-to-construct performance incentive mechanism (PIM) and the operational PIM. In addition, we instructed the Company to consider and potentially refile the Highly Confidential Exhibit 1 to the Response to Decision No. C23-0672-I.

48. On December 19, 2023, Public Service filed its Response to Decision No. C23-0841-I, providing the specific information requested, and a corresponding narrative on the identified highly confidential document.

49. The Commission resumed deliberations on December 20, 2023, and concluded deliberations that same day.

50. In addition to the public comment hearings and written comments provided in Phase I, throughout Phase II of this Proceeding, the Commission received numerous written public comments that the Commission reviewed and retains in the administrative record.

C. Phase I Decision and Public Service CEP

51. In the Phase I Decision, the Commission set the framework in which Public Service may proceed to issue RFPs for an all-source, competitive bidding process to meet its resource need and advance its CEP toward final consideration and approval. The Commission's rulings on topics such as the Company's coal action plan, workforce transition and community assistance, best value employment metrics (BVEMs), and the CEPR paved the way for the development of a CEP in Phase II that complies with the requirements of SB 19-236 and advances the establishment of a bold clean energy policy for Colorado.

52. The following list summarizes the primary rulings the Commission made in its Phase I Decision that relate to the Company's CEP and the requirements of SB 19-236:

a) Consistent with the Phase I Settlement, the resource acquisition period (RAP) for the Company's ERP/CEP extends through 2030 per § 40-2-125.5(4)(a)(I).
b) Subject to certain exceptions, starting in 2024, the Company must retire all RECs in the year generated, per § 40-2-125.5(3)(a)(III).
c) In the 120-Day Report, the Company will clearly distinguish between the set of resources necessary to meet customer demands in the resource acquisition period and the additional clean energy plan activities that may be undertaken to meet the clean energy target in § 40-2-125.5(3)(a)(I), per § 40-2-125.5(4)(a)(III).
d) In the 120-Day Report, the Company will set forth the actions and investments required to meet the clean energy target of § 40-2-125.5(3)(a)(I).
e) The Company will set forth a proposal for the CEPR as part of the 120-Day Report that enables us to consider the appropriate timing for Public Service to initiate the CEPR via an advice letter filing.
f) The suite of portfolios the Company will present in the 120-Day Report will allow the Commission to evaluate whether the proposed level of utility ownership comes at a reasonable cost and rate impact per § 40-2-125.5(5)(b).

g) Consistent with the Phase I Settlement, the 120-Day Report will include the information necessary for the Commission to consider BVEM in conjunction with our other Phase II decisions.

h) The Company will include the projected costs of both workforce transition plans and community assistance plans in the Phase II modeling. The estimated cost of the community assistance aspect will be equal to projected lost property tax revenues for six years following retirement (or conversion) for Hayden 1 and Hayden 2, and Pawnee (the Brush Coal plant), respectively, and ten years for Pueblo Unit 3, and will be offset by any new investment in the respective community.[32]

i) Public Service will file post-Phase II updated Just Transition Plans (JTPs) for the Hayden coal plants, the Brush Coal Plant, and Pueblo Unit 3.[33] Regarding the Pueblo Unit 3 in particular, no later than June 1, 2024, Public Service will file a JTP that includes a standalone competitive solicitation. To the extent not otherwise addressed in the Phase I Settlement, this 2024 Just Transition Solicitation (the 2024 JTS) shall be treated as an interim ERP under Rule 3603(a). While the focus of the 2024 JTS is the replacement of Unit 3 and the Pueblo community, the 2024 JTS is not geographically limited to the Pueblo area nor is the resource need limited to replacing Unit 3.[34]

j) The Phase II modeling will allow the Commission to evaluate both the social cost of carbon (SCC) and the social cost of methane (SCM), consistent with the spirit of § 40-3.2-106.

53. In addition, the Phase I Decision ruled on such things as the provisions in the Company's model PPA, the inputs and assumptions to be used in the Phase II modeling, and the portfolios and sensitivities that the Company will present in the 120-Day Report.

D. Phase II Filings

1. 120-Day Report

54. The 120-Day Report summarizes the results of the Public Service's Phase II modeling and puts forth the Company's Preferred Portfolio for Commission approval. Under the Preferred Portfolio, the Company would move forward with developing numerous generation resources and associated transmission infrastructure. While the relevant details of the 120-Day

[32] Phase I Settlement, pp. 18-19.
[33] Phase I Settlement, p. 19.
[34] Phase I Decision, pp. 40, 42; Phase I Settlement, pp. 27-31.

Report and the subsequent Updated Preferred Plan (UPP)will be discussed below, we highlight here some of the major components.

55. Public Service's Preferred Portfolio contains about half as much gas-fired generation resources as what the Phase I modeling predicted (628 MW versus 1,176 MW).[35] Conversely, the Preferred Portfolio adds almost twice as much renewable generation and six times as much storage as was anticipated in Phase I.[36] As to the storage specifically, Public Service states that the Preferred Portfolio takes advantage of the IRA tax benefits for storage, and uses storage to "effectively utilize otherwise curtailed renewable energy, provide critical ancillary services, and meet peak demand in the evenings when solar generation declines."[37]

56. Regarding emissions reductions, Public Service estimates that the Preferred Portfolio will achieve 87.4 percent reduction in CO2 emissions by 2030—far exceeding the 80 percent clean air target.[38] Public Service acknowledges, however, that "in addition to all of the normal variance in forecasting, the modeling process itself leads to structural optimism in emissions reduction potential" and that "real time operations will likely have less optimistic results than those predicted by the models."[39] The Company states that it "believes we would likely achieve an 80%-85% reduction."[40]

57. The emissions reductions are due largely to the Coal Action Plan and the renewable resources the Preferred Portfolio adds as replacement and new utility resources. Indeed, Public Service states that the Preferred Portfolio is "the largest portfolio ever advanced through the ERP

[35] 120-Day Report, p. 36.
[36] 120-Day Report, p. 36.
[37] 120-Day Report, p. 36.
[38] 120-Day Report, p. 38.
[39] 120-Day Report, p. 23.
[40] 120-Day Report, p. 24.

process."[41] Public Service estimates that through 2055 the Preferred Portfolio has a net present value (NPV) of approximately $44.2 billion. Included in this total price is an estimated $2.82 billion in transmission investments. By far the most significant portion of the total transmission investment is an estimated $2.2 billion needed for Denver Metro Transmission Network Upgrades.[42]

58. The Preferred Portfolio includes higher levels of Company-owned resources compared to past ERPs. Out of the 7,192 MW of nameplate capacity additions that would be acquired under the Preferred Portfolio, Public Service would own 66.6 percent of the capacity and 69.7 percent of the energy. The Company argues that the higher ownership percentage is a direct result of the more equitable tax credit policy for clean energy resulting from the historic IRA.[43]

2. CDPHE Verification

59. On October 18, 2023, CDPHE filed the Phase II CEP Verification Report. In its Verification Report, CDPHE opines that the GHG emissions reduction calculations for each portfolio submitted in this Phase II of Proceeding No. 21A-0141E are expected to be 80 percent or more below 2005 baseline levels. CDPHE further states that the portfolios "would be expected to achieve the minimum percent reduction levels required by the statutes for the CEP and Safe Harbor."[44]

60. In its Phase II CEP Verification Report, CDPHE lists the expected 2030 emissions reductions for each of the submitted portfolios. Of note, the expected emissions reductions for the Preferred Portfolio is 87 percent.[45]

[41] 120-Day Report, p. 22.
[42] 120-Day Report, p. 130.
[43] 120-Day Report, p. 40-41.
[44] CDPHE Phase II CEP Verification Report, p. 6.
[45] CDPHE Phase II CEP Verification, pp. 4-6.

3. IE Report

61. On October 21, 2023, the IE filed its Report in this Proceeding. In its Report, the IE attests that the Phase II process was conducted fairly and without bias. The IE states: "The IE can attest to the results of the evaluation and fidelity to the protocols and that the Phase I assumptions were used in evaluation. The IE also was unable to identify any bias towards or against any technology or respondent, including the options presented for the [Public Service] self-owned assets."[46]

62. That said, the IE also raised several recommendations for future ERP proceedings that the IE asserts will allow the process to better accommodate the large number of bids and increasing reliance on renewable resources. For example, the IE states that "inadequate time was allotted for the transmission analysis" and suggests changes going forward that allow for a better understanding of the transmission requirements associated with the proposed generation projects.[47]

4. Intervenor Comments

63. Numerous intervenors submitted comments on the 120-Day Report, including Staff, CEO, the UCA, CEC, CIEA, COSSA/SEIA, Interwest, WRA, the Conservation Coalition, Boulder, CRES, the OJT, and the Labor Interests.

64. Several parties, such as CEO, WRA, CRES, and Conservation Coalition, cite concerns with the Phase II modeling process and recommend selecting an alternative portfolio with fewer gas resources or simply removing some or all of the gas resources from the Preferred Portfolio.[48] Conversely, UCA argues that the Phase II modeling shows that eliminating gas-fired

[46] IE Report, p. 35.
[47] *See* IE Report, p. 37.
[48] CEO's Comments, pp. 13-14; WRA's Comments, pp. 15-17; CRES's Comments, p. 2; Conservation Coalition's Comments, pp. 12-13.

capacity is extremely expensive.[49] CEC similarly argues that the Commission should approve a less-costly portfolio that meets but does not greatly exceed the required emissions reductions.[50]

65. Some parties, including Boulder and UCA, suggest that the existing resources in the Preferred Portfolio could be replaced with other resources that they perceive to be lower-priced.[51]

66. Other parties representing IPP interests, like CIEA, argue that the Commission should choose an alternative portfolio that better balances how many resources will be owned by Public Service versus IPPs.[52] Conversely, the Labor Interests argue that there is a positive relationship between portfolios with high BVEM and portfolios with high Company-ownership numbers.[53]

67. At a high level, the parties have mixed opinions regarding the transmission investments presented in the 120-Day Report—some raise serious concerns while others argue the Commission should approve and expedite the transmission. Likewise, several parties raise cost and emissions concerns about the Hayden Biomass project, while other parties argue that the project should be included in any approved portfolio.

68. Out of the intervenors that filed comments, it appears that the Labor Interests, COSSA/SEIA, the OJT, and Pueblo County, do not oppose adoption of the Preferred Portfolio as presented.[54]

[49] UCA's Comments, p. 17.
[50] CEC's Comments, pp. 12-13.
[51] *See* UCA's Comments, pp. 20-24; Boulder's Comments, pp. 14-15.
[52] CIEA's Comments, pp. 12-15.
[53] Labor Interests' Comments, pp. 2.
[54] *See, e.g.*, Labor Interests' Comments, pp. 2; COSSA/SEIA's Comments, pp. 1-2.

69. For its part, Staff raises concerns that Public Service's Preferred Portfolio is too aggressive, too costly, and not well supported. Staff states that the Preferred Portfolio contains unexpectedly large generation and transmission investments and high levels of expected curtailments that together could lead to potentially large rate impacts for customers.[55] Staff encourages the Commission to consider selecting one of five smaller portfolios that would reduce expected curtailments, enable the Commission to defer some of the proposed projects, and to further analyze alternatives for the proposed transmission investments.

5. Comments from the Northern Cheyenne Nation

70. At the CWM on October 25, 2023, William Walksalong presented comments on behalf of the Northern Cheyenne Nation regarding the potential impacts to the Sand Creek Massacre National Historic Site. As described more below, tribal leaders urged the Commission to protect the Sand Creek Massacre National Historic Site as sacred grounds and its view shed from the encroachment of energy development.

6. Public Comments

71. After Public Service filed the 120-Day Report, the Commission received numerous public comments. Many of these public comments argue against the Preferred Portfolio's inclusion of three new-build gas facilities that Public Service would own. At a high level, these comments urge the Commission to reject the new natural gas plants, citing concerns regarding stranded costs, climate change, and air pollution. The Commission also received more substantive public comments from Leslie Glustrom, Advanced Energy United, Sustainable Resilient Longmont, and 350 Colorado that similarly argue for modifications to the Preferred Portfolio, including not approving the proposed gas facilities in the Preferred Portfolio.

[55] Staff's Comments, pp. 5-7.

72. In addition, the Commission received several comments from organizations and local governments like Upstate Colorado, Alamosa County, the City of Alamosa, Kiowa County, Prowers County, Baca County, and Pueblo County that support the Preferred Portfolio on the basis of emissions reductions and economic development. Of these supportive comments, several public comments specifically support the inclusion of the Hayden Biomass facility in the Preferred Portfolio, arguing that it will provide important economic benefits to Moffat and Routt Counties, which will be impacted by the closure of coal-fired power plants. Northwest Colorado Development Council, Routt County, Colorado State Senator Dylan Roberts, and the Town Council and Mayor of Hayden are some of the entities that submitted these types of comments specifically addressing the Hayden Biomass facility.

73. Since the Commission had its initial Phase II deliberations on December 6, 2023, we have continued to receive and review numerous public comments. At a high level, the majority of these most recent public comments urge the Commission to select a resource portfolio with fewer or no gas resources on the basis of climate change, air pollution, price volatility for natural gas, or concerns that the resources will become stranded. Several of the public commenters argue that the Alternative Portfolio is more expensive on a dollar per MW basis than the Company's UPP.

7. Public Service's Response Comments and the UPP

74. In its Response Comments, Public Service responds to criticisms and concerns raised by intervenors and public commentors and presents an UPP that modifies a few of the proposed generation projects. Aside from the modifications to a few of the generation projects, however, the Company largely maintains its initial position in the 120-Day Report.

75. For example, in response to arguments that the Commission should reduce or eliminate the amount of gas resources included in the portfolio, Public Service asserts that—due to reliability concerns—the Company "cannot become comfortable with any level of reduction in dispatchable resources."[56] Public Service argues that adjusting the portfolio by eliminating gas units or using questionable short-term power purchase agreement (PPA) extensions makes the portfolio less reliable and the Company "cannot compromise on reliability."[57]

76. As for arguments that the UPP has too many utility-owned resources or is too large, the Company argues that all of the selected clean energy projects are either build-own-transfer, PPA, or were purchased from IPPs by the Company earlier in the commercial lifecycle. Public Service agrees that the UPP is large but asserts that the size of the portfolio is ultimately driven by economics and state energy policy goals.[58]

77. Turning to the concerns raised about the approximately $2.8 billion in transmission investments, Public Service states that the ultimate decision before the Commission is approval of a generation portfolio and that "approval of a resource portfolio does not constitute a final approval of the transmission projects presented in the 120-Day Report."[59] Public Service maintains, however, that to achieve the State's emissions reduction goals, the Company must begin moving forward with the transmission investments needed to support the CEP.[60]

78. As for the proposed resource modifications under the UPP, in response to concerns that Bid 1029 could impact the Sand Creek Massacre National Historic Site due to its proximity, in the UPP, Public Service recommends that the Commission approve a specific backup bid for

[56] Public Service's Response Comments, p. 29.
[57] Public Service's Response Comments, pp. 27-29.
[58] Public Service's Response Comments, pp. 33-34.
[59] Public Service's Response Comments, p. 66.
[60] Public Service's Response Comments, p. 65.

Bid 1029 while still allowing Bid 1029 to move forward. Similarly, the Company proposes that the Commission conditionally approve the Hayden Biomass project but further analyze the costs, emissions reductions, workforce and community benefits, tax benefits, and viable alternatives in a follow-on CPCN proceeding.[61]

79. The Company proposes a few other changes to the resources in the UPP, but the suggested changes result from problems with the original resources as opposed to intervenor concerns.[62]

80. As compared to the Preferred Portfolio, the UPP adds 329 MW of nameplate capacity. This increase is comprised of an additional 101 MW of solar resources and an additional 228 MW of additional wind resources. The UPP is also $288 million more expensive on a present value revenue require (PVRR) basis.[63] Regarding the price increase, Public Service asserts that the $288 million increase is caused by unavoidable changes to bids that appear in virtually all portfolios. Thus, the Company asserts that all of the other portfolios would increase by the same amount, meaning there is little to no impact on the differences between plans.[64] The percentage of resources that the Company would own decreases slightly in the UPP from 66.6 percent of capacity to 62.7 percent.[65]

E. Modification of the CEP's Resource Portfolio

81. As described above, the statute prescribes when the Commission must approve a CEP and when the Commission may modify the CEP. Specifically, the Commission may modify the plan if the modification is necessary to ensure the plan is in the public interest. In evaluating

[61] Public Service's Response Comments, pp. 19-20.
[62] Public Service's Response Comments, pp. 18-24.
[63] Public Service's Response Comments, p. 9.
[64] Public Service's Response Comments, p. 9.
[65] Public Service's Response Comments, p. 9.

whether a CEP submitted to the Commission is in the public interest, the Commission shall consider (1) emissions reductions, (2) the CEP's impact on reliability and resilience of the electric system,[66] and (3) the cost of the CEP on a NPV basis. The statute also permits the Commission to consider "other relevant factors."

82. A CEP includes "clean energy plan activities that may be undertaken to meet the clean energy target… which may create an additional resource need for the [CEP]."[67] Public Service's CEP is thus comprised of several components, including the Coal Action Plan, the workforce transition and community assistance plans,[68] and the "investments required to fill the additional resource need,"[69] (*i.e.*, the portfolio of resources procured through the competitive solicitation). In this Proceeding, significant clean energy plan activities involve the conversion of the Brush plant from coal to gas and the lower capacity values of Pueblo Unit 3.[70] The UPP represents a portion of Public Service's CEP as proposed by the Company.

83. Given that the Company's preferred resource portfolio comprises a portion of the total CEP, the selection of an alternative resource portfolio does not replace the overall CEP. Because the Commission maintains the other important elements of the CEP—like the Coal Action Plan—the selection of an alternative portfolio is a modification to the overall CEP.

84. While the Commission recognizes that Company proposals in Phase I and II in this Proceeding have made progress towards Colorado's energy transition, there are significant

[66] The statute makes clear that the Commission "shall not approve a plan that does not protect system reliability." (§ 40-2-125.5(4)(d)(III), C.R.S.)
[67] § 40-2-125.5(4)(a)(III), C.R.S.
[68] § 40-2-125.5(4)(a)(VII), C.R.S.
[69] § 40-2-125.5(4)(a)(IV), C.R.S.
[70] Although the Coal Action Plan includes the early retirement of the Hayden and Craig coal plants, the coal actions are not technically part of the CEP because they are also included in the reference ERP portfolio.

concerns raised by parties and public commenters regarding the UPP.[71] For instance, Staff argues that given the large price tag of the Preferred Portfolio as well as the concerns Staff has about the Phase II modeling process, the Commission should reduce the size of the resource portfolio or delay decisions until further analysis and support can be provided.[72] Regarding its modeling concerns, Staff notes that Public Service's decision to increase the generic price of most renewables for years 2029 and 2030 might be causing the model to over-value acquisitions in the near-term.[73] Similarly, the reliability rubric the Company implemented in Phase II arguably prohibited the model from "backsliding" or removing resources after dispatchable resources were added. Staff states that the reliability rubric "introduced constraints into the capacity expansion step that fundamentally render the process suboptimal as it is no longer able to truly optimize the portfolio."[74] Staff goes on to suggest that the reliability rubric's constraints made the Commission-ordered demand response sensitivity ineffective.[75]

85. In addition, Staff notes that the Preferred Portfolio likely fails to account for high levels of curtailment and the resulting increase in costs and emissions. Staff argues that the model likely fails to capture significant levels of curtailments for several reasons, including the model's limitations regarding simplified commitment logic and the inability to capture curtailments from perturbations in the system as well as the timing mismatch between when generation will come online and when the transmission will be ready to serve the new generation. Staff ultimately concludes that the "the level and costs of curtailments portrayed by the model cannot be trusted"

[71] Because Public Service presented the UPP after intervenors submitted their Comments on the 120-Day Report, intervenors address the Preferred Portfolio rather than the UPP. The differences between the UPP and the Preferred Portfolio, however, are largely immaterial as to the concerns that the intervenors raise.
[72] Staff's Comments, p. 6.
[73] Staff's Comments, p. 28.
[74] Staff's Comments, p. 30.
[75] Staff's Comments, pp. 34-35.

and that the Preferred Plan "may saddle customers with extra costs for renewable energy that does not reduce emissions because it is never delivered."[76] In contrast, Staff notes that other portfolios presented in the 120-Day Report achieve comparable levels of emission reductions with much lower levels of curtailments and higher levels of storage.[77]

86. UCA also criticizes the Phase II modeling process and is especially critical of the May Valley Longhorn Extension (MVLE) and the most expensive part of the Denver Metro Area transmission upgrades—the Harvest Mile Chambers-Sandown-Cherokee (HCSC) project. UCA recommends that the Commission reject the HCSC, the MVLE, and the wind projects that UCA argues necessitate the transmission projects.[78]

87. Other parties, such as Conservation Coalition and CRES argue that the Commission should not approve any of the gas resources in the Preferred Portfolio.[79] CEO similarly recommends the Commission not approve 200 MW of the 628 MW of gas included in the Preferred Portfolio. CEO argues that it is unclear whether an additional 200 MW of new gas generation will actually be necessary and recommends that the Commission address this proposed new gas in future ERPs, including the 2024 JTS and the 2026 ERP.[80] WRA suggests that the Commission select the lower dispatchable portfolio, which has 504 MW of new gas generation—124 MW less than the Preferred Portfolio.[81] WRA also suggests modifying the Preferred Portfolio by reducing reliance on new construction and instead utilizing available existing generation.[82]

[76] Staff's Comments, pp. 31-32, 34.
[77] Staff's Comments, p. 32.
[78] *See* UCA's Comments, pp. 29-30.
[79] Conservation Coalition's Comments, p. 10; CRES's Comments, p. 2. Relatedly, the Commission has received numerous public comments urging the Commission to select a resource portfolio with fewer or no gas resources on the basis of climate change, air pollution, price volatility, or concerns that the resources will become stranded.
[80] CEO's Comments, p. 14.
[81] WRA's Comments, pp. 15-16.
[82] WRA's Comments, pp. 16-17.

88. CIEA raises several concerns with the Phase II modeling, arguing that the Company used a heavy-handed approach to manipulate the model.[83] Many of CIEA's recommendations are aimed at the goal of achieving a higher proportion of PPA resources in the Company's resource mix—both in this Proceeding and in future ERPs. CIEA asserts there have been "huge project cost overruns at the [Company-owned] Cabin Creek, Comanche, and Pawnee stations" and that customers are seeing less value than anticipated from two Company-owned wind projects.[84] CIEA argues that given the high percentage of Company-owned projects in the Preferred Portfolio, Public Service might be biting off more than it can chew.[85] CIEA reasons that PPA resources can help insulate ratepayers from both capital cost overruns and performance issues with generators. Noting that all of the gas resources in the Preferred Portfolio would be owned by Public Service, CIEA recommends that the Commission select an alternative resource portfolio that replaces some of the Company-owned gas-fired projects with existing PPA gas resources.[86] CIEA argues that PPA resources "should be at least 50% of Public Service's resource mix to balance ratepayer and shareholder risks."[87]

89. CEC argues that there are too many red flags and unknowns for this Commission to approve the Preferred Portfolio as presented. CEC notes that Preferred Portfolio will far exceed the clean air targets established by SB 19-236 and argues that the Commission should not approve a plan that goes "above and beyond" statutory requirements to the detriment of customers, particularly given the current affordability concerns.[88] For instance, CEC notes that the Preferred

[83] CIEA's Comments, pp. 26-28.
[84] CIEA's Comments, p. 13.
[85] CIEA's Comments, pp. 9-10.
[86] CIEA's Comments, pp. 16-18.
[87] CIEA's Comments, pp. 13-15.
[88] CEC's Comments, pp. 12-13.

Portfolio is approximately $600 million more expensive than the $0CO2 Least Cost Plan, and the $0CO2 Least Cost Plan still exceeds SB19-236 bold emission reduction targets.[89]

90. Given these concerns, and considering the record as a whole, we find that modification of the CEP in the selection of an alternative portfolio is necessary to ensure the plan is in public interest based on the three enumerated statutory factors as well as "other relevant factors" that the Commission defines.

91. As noted above, Staff recommends for several reasons that the Commission focus its consideration on five "portfolios of interest."[90] We agree with Staff and, consistent with the discussion below, determine that the Inverse 1324 ($0CO2) Plan best represents an "Alternative Portfolio" that incorporates the necessary modifications to Public Service's CEP to support the public interest findings required by SB 19-236.

92. Compared to the Preferred Portfolio set forth in the 120-Day Report, the Alternative Portfolio has 1,338 MW lower nameplate additions (7,192 MW – 5,854 MW). More specifically, the Alternative Portfolio has 19 MW fewer biomass, 41 MW more gas resources, 350 MW fewer solar resources, and 1,706 MW fewer wind resources. However, the Alternative Portfolio has 678 MW more storage resources.[91] The Alternative Portfolio also requires fewer transmission investments and is $194 million less expensive on a NPV basis. Regarding curtailments, the Phase II report suggests that in 2028 the Alternative Portfolio will result in 1,629 GWh of modelled curtailments, compared to 5,433 GWh of modelled curtailments in the Preferred Portfolio.[92] Moreover, the Company states in its Phase II Report that the modelled curtailment is the "best

[89] CEC's Comments, pp. 12-13.
[90] Staff's Comments, p. 11.
[91] *See* Staff's Comments, p. 49.
[92] *See* Staff's Comments, p. 49.

possible case scenario [rather] than a realistic expectation of [the curtailment level that]…would occur in real-time operations."[93] This uncertainty over actual curtailment levels further supports the more cautious approach taken with the Alternative Portfolio.

93. In addition, unlike three of the five portfolios of interest, the Alternative Portfolio was included in the 120-Day Report and thus was reviewed by the IE and CDPHE. As noted by Staff and confirmed by CDPHE, the emissions reductions resulting from the Alternative Portfolio exceed the 2030 greenhouse gas reduction targets. While the Alternative Portfolio has somewhat lower interim emissions reductions compared to the Preferred Portfolio, consistent with the Company's statements that the modeling does not capture curtailments resulting from transmission congestion and other perturbations in the system, Staff argues that it is unclear that the higher emissions reductions in the Preferred Portfolio "would bare out in reality" given the concerns regarding curtailments and the deliverability of the renewable energy.[94]

94. Moreover, the smaller size of the Alternative Portfolio addresses concerns raised by Staff and others that the Preferred Portfolio is too large due to factors such as the repricing of generic resources in the Phase II modeling and the no "backsliding" component of the Reliability Rubric modeling. Likewise, the smaller size ameliorates Staff's concerns about new generation coming online before the 2029/2030 in service date (ISD) for major transmission projects that Public Service indicates are necessary to take full advantage of the renewable resources.[95] Finally, the Alternative Portfolio reduces the Company's ownership percentage so that it is expected to be

[93] *See* 120-Day Report, at p. 95.
[94] Staff's Comments, p. 63.
[95] Staff's Comments, p. 61.

closer to the 50 percent IPP and 50 percent PPA statutory expectations.[96] Given the Company's significant upcoming investments in transmission through the Colorado Power Pathway and issues identified by intervenors of the Company's struggles to adhere to project budgets and timelines in different instances, a better balance between Company and IPP ownership presents an opportunity to decrease the risk of performance issues by a single entity impacting overall performance of the CEP.

95. Considering the statutory factors and additional public interest considerations raised in comments by parties and the public, based on this record and supported by party filings, we find that the Alternative Portfolio better aligns with Colorado's multi-faceted goals to achieve significant emission reductions and progress towards 100 percent emission reductions in the future, all while ensuring reliability and protecting affordability for ratepayers. Addressing specific factors below—and as supported by policy direction throughout our Phase II Decision that also includes PIMs and directives for the 2024 JTS—we find that modification of the CEP to include the Alternative Portfolio is necessary to ensure the CEP is in the public interest.

1. Emission Reductions

96. The statute requires the Commission to consider the emissions reductions associated with the CEP. Because the Alternative Portfolio is included in the 120-Day Report, CDPHE evaluated it along with all of the other Phase II portfolios in the Phase II Clean Energy Plan Verification Report. CDPHE opines that the emissions reduction calculations for each of the Phase II portfolios are expected to be 80 percent or more below 2005 baseline levels.

[96] To be clear, the Commission does not find that SB 19-236 in any way sets a floor or a ceiling for Company-ownership. The Commission does, however, find persuasive arguments from CIEA and others that more balanced levels of PPA and Company-owned resources help insulate ratepayers from potential cost overruns and performance issues.

Regarding the Alternative Portfolio in particular, CDPHE estimates that the expected 2030 emissions reductions will be 86 percent by 2030.[97] Thus, the Alternative Portfolio is expected to exceed the 80 percent emissions reductions set forth in the statute and makes progress towards achieving the goal of 100 percent clean energy resources by 2050.

97. As presented in the Phase II modeling, the UPP arguably achieves slightly greater emissions reductions, especially in the interim years prior to 2030. However, Public Service admits that these emissions reductions estimates are optimistic and that the model does not include curtailments caused by transmission congestion or perturbations in the system.[98] Thus, it is questionable how accurate these emissions reductions predictions are, especially in the interim years before Public Service has finished building the transmission upgrades the Company states are necessary to reliably deliver power.[99] In other words, these modeled interim emissions reductions are unlikely to materialize if Public Service cannot construct the majority of the associated transmission investments until 2030.[100] Moreover, it is these same transmission upgrades that resulted in the $2.2 billion "surprise" in Phase II, as discussed more below. We find it unsettling to rely on predictions that are speculative, at best, on transmission availability in the UPP that result in the seemingly higher emissions reductions. Given that the transmission modeling results changed dramatically between Phase I and II with costs escalating billions of dollars beyond the Company's initial estimates, we cannot depend on emission reduction predictions tied explicitly to those same transmission needs.

98. Throughout this Proceeding and in selecting the Alternative Portfolio, the Commission has considered the PVRR of both the social cost of carbon (SCC) and the social cost

[97] CDPHE Phase II CEP Verification, pp. 4-6.
[98] 120-Day Report, p. 95.
[99] 120-Day Report, pp. 130-133.
[100] *See* Staff's Comments, pp. 43-44 (citing Appendix Q to the 120-Day Report).

of methane (SCM), which also helps in our considerations on emission reductions. The Alternative Portfolio significantly reduces the SCC and SCM compared to Public Service's ERP or business-as-usual portfolio.[101] For the capacity expansion phase of the modeling, the Alternative Portfolio does not include the social cost of emissions.[102] Post-modeling, however, in the 120-Day Report the SCC and SCM associated with the Alternative Portfolio are both presented.[103] Moreover, the Coal Action Plan, which is critical to emissions reductions, is hardwired into the Alternative Portfolio. While there are other portfolios that have still greater reductions in SCC and SCM, notwithstanding the uncertainties around curtailment impacts to those figures, the Alternative Portfolio exceeds the 80 percent emissions reductions set forth in the statute while balancing other factors such as costs, reliability, and future optionality.

99. While the Alternative Portfolio—like other portfolios the Company claims protect reliability[104]—includes over 600 MW of gas resources, these gas resources do not impede Colorado's emissions reductions goals. Rather, the new gas resources are all equipped with both fast start and fast shutdown capability, which allows the units to sit idle most of the time while providing essential operating reserves and ancillary services.[105] The Commission reluctantly recognizes that there does not appear to be a path forward that excludes or significantly reduces the need for new gas resources, given the Company's repeated assertions that it cannot support any reduction in gas resources based on the Company's reliability analysis[106] and the lack of modeling demonstrating the contrary within the record.

[101] 120-Day Report (Appendix S) Rev. 1, pp. 1, 26.
[102] 120-Day Report, p. 97.
[103] 120-Day Report (Appendix S) Rev. 1, p. 26.
[104] Public Service argues that the No New Gas and No Gas Portfolios are not reliable. The Lower Dispatchable portfolio includes somewhat fewer gas resources (504 MW), but the Company has raised reliability concerns with this portfolio as well. (Public Service's Response Comments, pp. 29-30).
[105] 120-Day Report, pp. 80-81, 126.
[106] Public Service Response Comments, p.29

100. Moreover, as discussed more below, rather than simply eliminating 200 MW of gas-fired resources as argued by some parties and sacrificing reliability, the Alternative Portfolio reduces the amount of Company-owned gas resources, increasing the Company's ability to fully transition away from carbon emitting resources as we approach 2050 and reducing risk of stranded assets to ratepayers. This reduction in Company ownership provides continued opportunities to further accelerate towards 100 percent renewable resources by not tying the Company – and Colorado – to the full amount of utility-owned gas-fired resources presented in the UPP.

101. Under SB 19-236, the CEP must achieve 80 percent emissions reductions by 2030 while working towards 100 percent clean energy by 2050, and the Commission must consider reliability and affordability when determining whether the CEP is in the public interest. The Alternative Portfolio with its 669 MW of gas resources provides this balanced, transitional plan that SB 19-236 contemplates. Even though the gas resources will be run infrequently with the vast majority of the energy coming from wind and solar resources, the units provide an important insurance policy during sustained periods of hot or cold weather – including in extreme circumstances given the realities of climate change.[107] Providing this backup option and permitting the integration of substantial additions of new clean energy resources allows Public Service to retire its remaining coal plants and several of its older gas units.[108]

102. In sum, when considering emission reductions, the Alternative Portfolio exceeds Colorado's ambitious emission reduction goals, sets the state towards a path for 100 percent renewable resources, all while continuing to avoid extreme costs and outages.

[107] 120-Day Report, pp. 22-23, 80-81.
[108] 120-Day Report, pp. 22-23, 80-81.

2. Reasonable Cost to Customers

103. The statute requires the Commission consider if the CEP will result in a reasonable cost to customers on an NPV basis. The NPV of the UPP is $44,479 million while the NPV of the Alternative Portfolio as presented is $43,997 million.[109] However, in its Response Comments, Public Service states that the $288 million NPV increase from the Preferred Portfolio to the UPP is a result of unavoidable changes that would appear in virtually all portfolios.[110] Assuming that the same incremental change appears in the Alternative Portfolio, the updated NPV of the Alternative Portfolio is $44,285 million ($43,997 + $288 = $44,285). Even using this updated NPV, the Alternative Portfolio is $194 million less expensive than the UPP ($44,479 - $44,285 = $194).

104. While the Alternative Portfolio is preferable to customers on an NPV basis as contemplated in SB 19-236, another relevant factor the Commission must consider is the cost to customers as experienced through increased rates. Intervenors such as Staff, UCA, and CEC have raised alarms regarding the Preferred Portfolio's impact on rates. For instance, Staff states that the rate increase attributable to the Preferred Portfolio for the single year from 2026 to 2027 is just over 10 percent.[111] As discussed more below, the rate analysis the Company provides in the 120-Day Report only includes the impact of the CEP and fails to include other planned investments such as $4.5 billion in projected distribution investments through 2028, an additional $800 million in generation projects outside of the CEP, as well as investments in wildfire mitigation, transportation electrification, distributed solar, and others.[112] Staff asserts that the impact of real time operations, construction schedules, system curtailments, and other factors will likely result in

[109] Public Service's Response Comments, p. 9; 120-Day Report (Appendix S) Rev. 1, p. 26.
[110] Public Service's Response Comments, p. 9.
[111] Staff's Comments, p. 19.
[112] *See* Staff's Comments, p. 19.

higher rate impacts than the Company's calculations suggest.[113] Given the importance of maintaining affordability, the Commission must consider these costs to customers more generally and not limit our consideration to the NPV comparison of the various resource portfolios.

105. An example of a cost to customers that does not explicitly appear in the NPV considerations is the likely cost of curtailments that the modeling fails to capture. Although the NPV estimates do include the costs of curtailments included in the modeling, the Company admits as discussed above that the model's curtailment forecasting is "more a 'best possible case scenario' than a realistic expectation of what would occur in real time operations."[114] Public Service notes that "a large percentage of curtailment" is caused by perturbations in the system from transmission issues or reliability events and that these curtailments "are not captured in the model."[115] The curtailments resulting from transmission issues are especially concerning given that under the UPP the Company will be connecting vast amounts of new renewable generation years before most of the associated transmission upgrades can be constructed.[116] The Company indicates that while the transmission investments are being built, Public Service will maintain reliable service using tools such as curtailments and redispatch.[117] Thus, the NPV calculations do not reflect significant amounts of curtailments that the modeling fails to capture, but these missing curtailments will result in additional costs that customers must pay.

106. The Alternative Portfolio cuts modeled curtailments from 15 percent in the UPP to 5 percent,[118] and curtailments that the model does not capture will likely also be reduced due to a decreased reliance on yet-to-be-built transmission and an increased investment in storage. By way

[113] Staff's Comments, p. 19.
[114] 120-Day Report, p. 95.
[115] 120-Day Report, p. 95.
[116] *See* Staff's Comments, pp. 43-44.
[117] 120-Day Report, p. 134.
[118] *See* Staff's Comments, p. 49.

of analogy, Public Service predicts that the UPP will have 6,043 GWh of curtailments in 2028,[119] but the Alternative Portfolio is only predicted to have 1,629 GWh of curtailments in 2028.[120] It is reasonable to assume that curtailments that the model fails to capture will follow similar trajectories resulting in significant additional costs savings in the Alternative Portfolio.

107. Put simply, the Alternative Portfolio will achieve the state's ambitious clean energy targets while mitigating the risk that ratepayers will be required to pay for resources that have less incremental value because they are significantly curtailed.

108. Another category of costs that does not appear in the NPV calculations are the potential costs associated with Company-owned gas generation assets, including construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will become stranded. On this last point, several parties including UCA, WRA, Conservation Coalition, and Boulder, as well as numerous public comments, raised concerns that the new gas resources will become stranded assets. The Alternative Portfolio is again preferable to the UPP in this regard because it contains a substantial decrease in Company-ownership of new gas capacity. Specifically, the UPP contains 628 MW of new build gas resources, all of which are Company-owned.[121] The Alternative Portfolio contains 669 MW of new build gas resources, but of this 669 MW, 219 MW is a PPA resource with a 20-year term.[122] By diversifying the ownership of the gas resources, the Alternative Portfolio reduces the risks that customers will be saddled with future costs associated with Company-owned gas resources.

[119] Public Service's Response Comments, Attachment 2, p. 1.
[120] 120 Day Report (Appendix T), p. 23.
[121] Public Service's Response Comment, p. 9.
[122] 120-Day Report (Appendix S) Rev. 1, p. 26.

109. Finally, yet another cost that is not included in the NPV estimates is the risk that a larger, more sprawling resource portfolio like the UPP will eliminate opportunities to take advantage of future technology developments or reductions in price in some of the newer technologies. As discussed more below, acquiring a smaller portfolio of resources in this Proceeding creates more optionality in future proceedings for efficiencies and cost savings, including through a more robust use of demand side resources. In other words, the Alternative Portfolio reduces the risk that customers will pay for generation and transmission resources that could have been avoided through better use of developing technologies.

110. As we consider costs, we believe that least-cost options presented in the Phase II report may be unworkable for Colorado. We find unpersuasive arguments raised during Phase II that the Commission should select the Least Cost Portfolio. While the Least Cost Portfolio is slightly less expensive on a NPV basis than the Alternative Portfolio,[123] the Company has raised reliability concerns with the portfolio because it does not include the strategically located gas resources the Company asserts are necessary for transmission support.[124]

111. Similarly, we reject arguments that selecting a larger portfolio to reduce emissions at any cost is appropriate. It is critical that we examine costs and emissions together, and in conjunction with reliability as required by statute. Not only is the diverse technical makeup of the Alternative Portfolio needed for the reliability needs raised by the Company and discussed more below, but because of the increase in storage in the Alternative Portfolio, modifying the CEP to move forward with this portfolio also allows further development with not only load but storage capacity that could help increase efficiencies and reduce costs in the future. In addition,

[123] The Least Cost Portfolio has a PVRR of $43,984 million, which is $13 million less than the Alternative Portfolio's PVRR or 43,9997. (120-Day Report, p. 38; 120-Day Report (Appendix S) Rev. 1, p. 26).
[124] 120-Day Report, pp. 39-40; Public Service's Response Comments, p. 29.

overinvesting in the system could price electricity out of competition with other fuels, jeopardizing beneficial electrification efforts.[125] To help ensure that Colorado can continue to decarbonize all sectors of the economy—many parts of which will rely on the electrical system as the backbone of the transition—it is essential to provide electrical service at a reasonable cost and rate impact.

112. Finally, CRES and certain public commentors note that Public Service's NPV cost numbers were calculated using the Company's weighted average cost of capital (WACC) as the discount rate, and they urge the Commission to use a lower discount rate. CRES argues that using the WACC as the discount rate will have the effect of discounting future fuel and other costs sharply. Moreover, CRES states that in enacting SB 23-291, the legislature has directed the Commission in C.R.S. § 40-2-139 to use a discount rate for future fuel costs that does not exceed the long-term rate of inflation. CRES recommends that the Commission direct the Company to resubmit the NPV values in accordance with what is now Colorado law.[126]

113. We note that the appropriate use of discount rates was litigated in Phase I. The Phase I Decision put forward a compromise to help mitigate the substantive concerns raised by CRES, requiring Public Service to provide in Phase II the annual nominal cash flows associated with each portfolio so that the parties and the Commission could calculate the NPV calculation using various discount rates.[127] As such, this Commission believes it is important to understand the potential cost and other resource choice impacts that might occur at lower discount rates, but

[125] Numerous public commenters argue that the Alternative Portfolio is more expensive than the UPP on a dollars per MW basis. This argument only looks at the nameplate capacity of the respective portfolios and does not account for important distinctions in how different resources contribute to the electrical system. For example, a 300 MW solar facility will be of no value to the electrical system after the sun sets. A 300 MW solar plus storage facility, however, is able to help serve load after the sun sets and, in this way, can be more useful to the electrical system, even though it has the same nameplate capacity as the solar facility. Thus, the addition of storage resources to a portfolio can contribute value in ways that are not reflected in the amount of nameplate capacity.

[126] CRES's Comments, pp. 2-3.

[127] Phase I Decision, ¶ 211.

declines to upset the compromise position we adopted in the Phase I decision particularly since the Company did provide the requested Excel worksheet as Appendix W to the 120-Day Report.

114. Likewise, we reject CRES's argument that the Commission is required in this Phase II process to use an alternative discount rate per SB 23-291's amendment to C.R.S. § 40-2-139, which would further extend the Phase II process with additional modeling and process by relitigating issues resolved in Phase I. CRES is correct that, going forward, the requirement imposed by the amended § 40-2-139, C.R.S. imposes a duty on the Commission that, if it relies on the use of a discount rate when calculating NPV of future carbon-based fuel costs, the rate must not exceed the long-term rate of inflation. However, the law does not consider or include the necessary Phase I and II process or other clarifications.

115. A law is presumed prospective unless the legislature "clearly and unequivocally expressed" [128] intent for the statute to apply retrospectively. Generally, when the cause of action "accrues prior to the effective date of an amending statute," the prior statute controls.[129]

116. Here, Public Service filed its application in this Proceeding in March 2021. At that time, and at the time of the Phase I order, the statute did not include the updated language, which went into effect in August 2023. The party evidence and record overall, including the expectation of the Company when it filed the application, were set well before the 2023 legislative session. The issue was fully concluded through the Phase I Decision issued in 2022. To change the required scope of the considerations at this late phase is not required and counters long-standing precedent.[130]

[128] Edelstein v. Carlile, 33 Colo. 54, 57, 78 P. 680, 681 (1904)

[129] United Bank of Denver Nat. Ass'n v. Wright, 660 P.2d 510, 511 (Colo. App. 1983*);* Diversified Veterans Corp. Ctr. v. Hewuse, 942 P.2d 1312, 1314 (Colo. App. 1997) (holding that the imposition of penalties involves substantive rights and liabilities and is therefore governed by the law in effect on the date of the party's injury).

[130] *See, e.g.*, United Bank of Denver Nat. Ass'n v. Wright, 660 P.2d at 511.

117. Phase I is complete and has always been the appropriate phase for determination of the applicable discount rate. In enacting its statute in 2023, the Legislature is presumed to understand this process, and the Commission certainly will be required to apply the statute in future ERP Phase I decisions that direct the necessary considerations of discount rate determinations. The Commission is not, however, required to alter its Phase II process and extend already tight timelines for further modeling, analysis, and to expand the record. Indeed, if it did, these actions would potentially put at risk the time-sensitive bidding process.

118. Nevertheless, as the Commission did in its Phase I order in considering updates to statute subsequent to the 2021 ERP application filing by directing the Company to include the social cost of methane in its Phase II information, the Commission is in no way precluded from recognizing the statutory considerations and discussing the spirit and application based on the record. The Commission generally has a broad delegation of power to regulate utilities from the Colorado legislature.[131] Where the legislature has not directly prohibited the Commission from considering certain factors, the Commission generally can exercise its power over rates and utilities as it sees fits.[132] Specifically, when approving resource plans, the Commission can consider "other relevant factors, as determined by the commission."[133] The legislature grants the Commission broad power here to determine what factors are appropriate to use to compare bids in a resource plan.[134] Recognizing these statutory provisions, the record here indicates that the Alternative Portfolio would still be the most appropriate selection.

119. No parties to this Proceeding submitted analysis during Phase II showing the PVRR of various portfolios using a lower discount rate, although certain public commentors submitted

[131] *See* City of Montrose v. Pub. Utils. Comm'n*,* 629 P.2d 619, 622 (Colo. 1981).
[132] *See* § 40-3-102, C.R.S.
[133] § 40-3.2-106(3)(c), C.R.S.
[134] § 40-3.2-106(3)(c), C.R.S.

analysis regarding the impact of different discount rates on the NPV of fuel costs. Regardless, even assuming that certain that a lower discount rate makes the Alternative Portfolio more expensive on a NPV basis compared to the lower dispatchable portfolio, the no new gas portfolio, and the no gas portfolio, this does not justify the selection of a different portfolio. First, the Commission is still prohibited from selecting a portfolio that fails to protect reliability. Public Service states in its Response Comments: "neither the No New Gas Portfolio nor the No Gas Portfolio protect system reliability and therefore cannot be approved by law."[135] Public Service has also raised concerns with the reliability of the lower dispatchable portfolio. Moreover, while one of the enumerated statutory factors is the cost on a NPV basis, the statute permits the Commission to also consider other relevant factors. One such unenumerated factor the Commission is considering is the cost to customers more generally. Through this lens, the lower dispatchable portfolio, the no new gas portfolio, and the no gas portfolio all require significantly more resource acquisitions in the short term that will have significant consequences for the affordability of electric service. This factor weighs in favor of granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio.

3. Reliability and resilience of the electric system

120. The statute also requires the Commission to consider the impact of the CEP on the reliability and resilience of the electric system and prohibits the Commission from approving a plan that does not protect system reliability. Based on modeling in this record, the Alternative Portfolio is just as reliable, if not more so, than the UPP.

121. As presented by the Company, gas-fired generation resources are a key factor in ensuring reliability. In response to arguments that the Commission should reduce the amount of

[135] 120-Day Report, p. 60.

gas resources, Public Service asserts that it "cannot become comfortable with any level of reduction in dispatchable resources."[136] In addition to the total amount of gas resources included in the portfolio, Public Service asserts that two gas resources within the UPP are strategically located and necessary to provide transmission support: Bid 989 in the Denver Metro area and a new gas resource in the Alamosa area. Regarding Bid 989, the Company states that it "is the only bid submitted that includes firm dispatchable generation providing supportive benefit to the transmission constraint" in the Denver Metro area.[137] Similarly, the Company notes that, after a 2026 retirement of an existing gas resource, there will be no firm dispatchable resources located in the San Luis Valley. The Company asserts that it is essential from a reliability perspective to continue to have firm dispatchable generation in the region.[138]

122. The Alternative Portfolio slightly increases the amount of gas resources included in the UPP and retains the two gas resources that Public Service argues are strategically located and necessary to provide transmission support.[139] The only modification the Alternative Portfolio makes to the gas resources in the UPP is to Bid 1000, which the Company does not flag as being necessary for transmission support.[140] Bid 1000 is a Company-owned project with two 200 MW combustion turbines (CTs). The Alternative Portfolio would eliminate one of the 200 MW CTs in Bid 1000 and replace it with a 219 MW CT (Bid 235) that is owned by an IPP. As set forth above, this change provides valuable diversification benefits that, among other things, reduces the risk of stranded assets that customers face from Company-owned gas resources. In addition, Public Service has raised no reliability concerns with Bid 235. Indeed, Bid 235 is included in the backup

[136] Public Service's Response Comments, p. 29.
[137] 120-Day Report, p. 39.
[138] 120-Day Report, p. 39.
[139] 120-Day Report (Appendix S) Rev. 1, p. 26. While the Alternative Portfolio replaces the UPP's Alamosa gas resource with a slightly larger gas resource that is also located in the Alamosa area.
[140] 120-Day Report, p. 29.

portfolio and is the only gas bid that the Company includes in its Prospective New Load portfolio.[141] Thus, the Alternative Portfolio maintains or increases the reliability of the UPP in that it retains the two strategically located gas resources, slightly increases the total amount of gas resources, and replaces a Company-owned gas resource with a PPA resource that the Company has found to be reliable.[142]

123. Furthermore, the Company ran both the Alternative Portfolio and the Preferred Portfolio (which closely resembles the UPP) through an "extreme summer" scenario that—according to the Company—"provides useful information on the reliability of the portfolios under extreme events."[143] Under this extreme summer scenario, the Alternative Portfolio performed better than the Preferred Portfolio.[144] Thus, we are left to conclude that the Alternative Portfolio is not only reliable based on Public Service's own metrics, it appears to be more reliable than the UPP.

124. Although the UPP and the Alternative Portfolio have comparable levels of gas-fired generation, we acknowledge the arguments from several parties and numerous members of the public that the Commission should only approve a resource portfolio with fewer or no new gas resources. We share their disappointment that the Phase II competitive resource solicitation failed to result in any viable portfolio with fewer gas resources and again urge the Company to come

[141] 120-Day Report, p. 55; Public Service's Response Comments, p. 27.

[142] Pursuant to the Phase I Settlement and the Phase I Decision, the model PPA for dispatchable resources was amended to, among other things, require that gas resources have backup fuel on site necessary to allow the facility to run continuously for a minimum of five days at maximum load on the alternative fuel. Firm gas transportation contracts could serve as a substitute for the requirement to have a backup alternative fuel on site. (Phase I Decision, pp. 106-06; 120-Day Report, pp. 122-23). In the 120-Day Report, Public Service confirms that "[a]ll bids that were advanced to EnCompass modeling are compliant with the requirement for either onsite backup fuel storage or firm gas transportation contracts" but that the model did not select the fuel oil storage bids due to economics. (120-Day Report, p. 125). The Commission reiterates its interest in having five days of backup fuel onsite for the new gas resources.

[143] 120-Day Report, p. 77.

[144] Corrected Table 19 of 120-Day Report, p. 1.

forward in future proceedings, including the 2024 JTS, with more developed demand side resources and other reliability solutions that do not involve new gas resources. As described above, the requirement to include at or near the amount of gas resources in the Alternative Portfolio stemmed from the Company's reliability determinations and their direct modifications to the modeling in Phase II, as a result. The Commission is disappointed that specific, locational reliability concerns were not clearly communicated in Phase I, which could have been informative to potential bidders and provided additional options.

125. We therefore find that granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio, including its gas resources, is in the public interest. First, SB 19-236 prohibits the Commission from approving a plan that does not protect system reliability. Thus, we cannot simply carve out from a modeled resource portfolio some or all of the firm dispatchable resources that Public Service maintains are necessary for reliability.

126. Other modeled resource portfolios with fewer gas resources than the Alternative Portfolio were presented by Public Service—including the Lower Dispatchable portfolio, the No New Gas portfolio, and the No Gas portfolio. None of these portfolios, however, represent a better option than the Alternative Portfolio. Public Service states in its Response Comments that "neither the No New Gas Portfolio nor the No Gas Portfolio protect system reliability and therefore cannot be approved by law."[145] In addition, we note the No New Gas portfolio and the No Gas portfolio are significantly larger and more costly than the Alternative Portfolio.

127. As for the Lower Dispatchable portfolio, it is much larger than the Alternative Portfolio (7,163 MW instead of 5,835 MW) and more expensive on a NPV basis ($45,315

[145] 120-Day Report, p. 60.

compared to 43,997).[146] Moreover, as compared to the Alternative Portfolio, the Lower Dispatchable portfolio simply reduces the amount of PPA gas resources by selecting a smaller CT (Bid 1061). The Company-owned gas resources are essentially unchanged.[147] In addition, the Company argues in its Response Comments that it has reliability concerns with Bid 1061.[148] Thus, on this record we find that the Alternative Portfolio is superior to the Lower Dispatchable portfolio, the No New Gas portfolio, and the No Gas portfolio.[149]

128. Even though we would have preferred selecting a portfolio with fewer or no gas resources, we find it useful to consider the total amount of gas resources in the context of what was originally anticipated in Phase I of this Proceeding. Based on the inputs and assumptions established in the Phase I Settlement, the modeling predicted that the competitive solicitation could lead the Company to acquire 1,372 MW of gas additions.[150] The vast majority of the parties in this Proceeding joined the Phase I Settlement, including CEO, WRA, and Conservation Coalition. Thus, we conclude that the 669 MW of gas resources in the Alternative Portfolio are well within the guardrails established in Phase I.

129. While we find on this record that the Alternative Portfolio and its gas resources are in the public interest, we acknowledge the numerous concerns that parties raised regarding how Public Service tested for reliability in the Phase II modeling and the manual adjustments the Company made regarding gas resources. In particular, we share the concerns raised by parties

[146] 120-Day Report (Appendix S) Rev. 1, pp. 26, 28.
[147] 120-Day Report (Appendix S) Rev. 1, pp. 26, 28.
[148] Public Service's Response Comments, p. 30.
[149] For similar reasons, we reject CIEA's arguments that the Commission select a portfolio that use the annuity tail instead of the replacement chain modeling. As between the Alternative Plan and the Alternative Plan with the annuity tail, the new 219 MW PPA CT (Bid 235) is replaced with three short-term extensions of existing PPA CTs, but the Company-owned gas resources remain essentially the same. The record before us better supports the reliability of Bid 235 as compared to the extensions of the existing PPA CTs. Moreover, because the annuity tail version is just a sensitivity, its projected emissions have not been reviewed by CDPHE.
[150] Public Service's Response Comments, p. 28 (citing Phase I Settlement (Attachment D), at Table 3 and noting that the 1,372 MW of gas additions is over a longer RAP).

such as Staff, COSSA/SEIA, and Conservation Coalition regarding the Company's reliability rubric.[151] We also question whether the Company adequately communicated to bidders the importance of strategically located gas resources. It is our expectation that the Company will strive to resolve these issues prior to the 2024 JTS. Nevertheless, while these concerns further support our decision to select a tailored resource portfolio, we are unconvinced that these concerns warrant additional Phase II modeling or the manual removal of gas resources from the modeled portfolios.

4. Future Technology Development

130. Another related factor that the Commission considers when evaluating the CEP is the impact of future technology developments. For instance, the Alternative Portfolio includes a much higher percentage of storage resources than the UPP. This significantly expanded level of storage may be critical to future efforts to incorporate still greater amounts of renewables without unreasonable levels of curtailments while reducing the need for gas resources.

131. Colorado's bold clean energy targets necessitate a rapid shift in the electrical system, which in turn requires us to think about our electrical system in a different way. We cannot attempt to build Colorado's future, low-emission electrical system by continuing to build the system as we have in the past. Simply building increasing amounts of generation resources as the UPP would do results in high curtailments and high costs. In contrast, modifying the CEP to include the Alternative Portfolio helps the Commission start building a different type of electrical system that takes advantage of developing technologies in several ways. Efficient and cost-effective planning of such a system will rely on a variety of components: flexible supply, flexible demand, participation in larger geographic markets, energy efficiency and acquisition of

[151] *See, e.g.*, Staff's Comments, pp. 29-30; COSSA/SEIA's Comments, pp. 14-15; Conservation Coalition's Comments, pp. 10-13.

clean resources. While other dockets are addressing regional markets, demand flexibility and energy efficiency, in this CEP we address clean resources and flexible supply, placing a greater emphasis on supply management through increased storage capacity. As an example, energy storage resources in the Alternative Portfolio represent 32 percent of new capacity, [152] compared to just 16 percent in the UPP.[153] In this way, the Alternative Portfolio marks the first step in a new approach to resource planning for a modern, efficient, and cost-effective grid.

132. In addition, the modification of the CEP to include the Alternative Portfolio results in a smaller, less aggressive resource acquisition. Although it is likely that our selection of a smaller resource portfolio in this Proceeding will result in a larger acquisition in the 2024 JTS, deferral of some of the new generation resources will also provide additional time for the Commission to better understand and take advantage of developing technologies that might reduce the cost of, or eliminate the need for, new generation and transmission resources. In this vein, the Alternative Portfolio's acquisition of a PPA gas resource reduces the amount of gas resources that Public Service would otherwise own.[154] This gives Public Service more flexibility if future technology improvements render gas resources unnecessary. Moreover, advancements in various types of distribution system management are particularly promising for ensuring that the distribution system is more capable of the dynamic load management that will be more important as beneficial electrification advances. The Commission also expects that more robust and innovative demand response programs will be a critical part of the future electrical system. As more items like electric vehicles, heat pumps, and heat pump water heaters come onto the grid, the management of these loads will become increasingly important, but also increasingly possible.

[152] Staff's Comments, p. 11.
[153] Public Service's Response Comments (Attachment 1), p. 1.
[154] *See* 120-Day Report (Appendix S) Rev. 1, p. 26.

To ensure that the Commission is being good stewards of ratepayer funds, we need the Company and their planning processes to evolve away from overbuilding resources and instead look for ways to enable more dynamic management of both supply resources and demand resources.

133. Several parties similarly argue that the Commission should continue examining how new technological developments could be used to meet system needs instead of traditional generation and transmission investments. For instance, WRA suggests that the need for some of the Denver Metro transmission upgrades could instead be addressed by load management programs. WRA states that investment in transmission system upgrades to alleviate the Denver Metro constraint may be needed but recommends that the Company develop without delay load management programs in the metro area. WRA also recommends that the Company improve distributed energy resource (DER) programs and interconnection rules, with financial incentives to ensure the growing DER capacity provides benefits to the grid.[155]

134. Similarly, noting that the Company's proposal for metro Denver transmission upgrades was "significantly influenced by the lack of cost-effective bids [for generation] in the Denver metro area," COSSA/SEIA asserts that the Company should consider alternatives to conventional transmission upgrades, including non-wires alternatives such as virtual power plants (VPPs).[156] CEO likewise encourages the exploration of non-wires alternatives associated with the proposed upgrades in its new Distribution System Plan as well as additional details in the 2024 JTS.[157] CRES argues that with the new storage contained in the Preferred Portfolio, together with the fact that long-term storage technologies are evolving quickly, the Commission should not

[155] WRA's Comments, p. 22.
[156] COSSA/SEIA's Comments, pp. 22.
[157] CEO's Comments, pp. 29-30.

approve the proposed gas resources until Public Service has gained significant experience operating its system with the large amount of storage that will be added in the coming years.[158]

135. Staff asserts that Public Service never mentioned the possibility of demand side or other generation solutions to alleviate the $2.1 billion in transmission in the Denver Metro area. Staff notes that demand response solutions, aggregation of customer-sited generation and storage, and the use of electric vehicles to deliver grid benefits are being discussed in the Commission's Distribution System Plan proceedings and VPP Miscellaneous Proceeding. Staff argues that it is unclear whether solutions such as Time-of-Use rates, critical peak pricing, additional demand response, VPPs focused on this period, managed charging, Vehicle-to-Grid programs, strategically located storage at Community Solar Gardens, etc. could prove to be more cost-effective solutions than what the Company proposes.[159]

136. Future development also implicates changing needs for workforce labor and development. Despite the many positive attributes of the Alternative Portfolio, we have not lost sight of best value regarding employment of Colorado labor and the impacts the Alternative Portfolio will have on the long-term economic viability of Colorado communities.[160] As set forth more below, the 120-Day Report assigns a BVEM score to each portfolio and the Alternative Portfolio's BVEM score is slightly lower than the UPP's BVEM score. Although it is disappointing that the Alternative Portfolio has a lower BVEM score, just as deferral of some of the new generation resources will provide additional time for the Commission to take advantage of developing technologies, the Alternative Portfolio allows time for better evaluation of BVEM for those resources that will be acquired in future solicitations. Notably, the BVEM scores appear

[158] CRES's Comments, p. 2.
[159] Staff's Comments, p. 41.
[160] *See generally* § 40-2-129(1)(a), C.R.S.

to track to some degree with the percentage of utility ownership, so as IPPs prepare for future solicitations, they should take special care to improve BVEM performance to ensure that in future solicitations the Commission does not see lower BVEM scores as a reason to disturb the ownership balance between the utility and IPPs. Ultimately, we believe that the positive attributes of the Alternative Portfolio, including cost, emissions reductions, reliability, and the ability to better address future technology developments and transmission concerns, outweigh the lower BVEM score.

137. In sum, the prospect of future technology developments weighs in favor of modifying the CEP to include the resources in the Alternative Portfolio. The composition of the Alternative Portfolio itself with the large amounts of storage will likely be key for the future low emissions electrical system. Likewise, the more tailored acquisition of resources provides the Commission with more opportunities to evaluate quickly advancing technologies such as distribution management and new demand response programs and balances the risk that some of these new technologies could reduce the need for future generation and transmission investments.

5. Transmission Concerns

138. The transmission concerns that have arisen in Phase II are another factor that contributes to the finding that granting Public Service authority to move forward with acquiring the resources in the Alternative Portfolio is necessary for the public interest. The Company presents several categories of transmission costs, but all are overshadowed by the $2.2 billion in investments for transmission network upgrades to the Denver Metro area.[161] In Phase I of this Proceeding, the Company identified a need in the Denver Metro area, but only estimated the need

[161] 120-Day Report, p. 130.

at a capital cost of "approximately $250 million".[162] Therefore, the Phase II modeling did not consider the new and significantly larger cost or how to minimize or avoid it as part of the resource selection process. Moreover, as noted above, the majority of the transmission investments are not scheduled to be completed until 2030, years after many of the resources in UPP would otherwise come online,[163] exacerbating concerns regarding both the modelled and actual levels of curtailments that will occur in the UPP.

139. As discussed in more detail elsewhere in this Decision, several parties raise concerns about the $2.2 billion investment in transmission upgrades that Public Service states is necessary for the Denver Metro area and question whether the selection of resources could be better optimized to reduce the transmission upgrades. For example, Staff states that there "seems to be a fundamental problem that the modeling process does not integrate transmission planning in a meaningful way" and notes that Public Service "has not provided any analysis of the amount and type of metro area generation that would be needed to reduce this transmission network upgrade cost or the amount by which it could be reduced."[164] Staff argues that the $2.2 billion surprise raises several questions including whether the transmission costs would be substantially different under any other generation portfolio, whether there are cost effective Denver Metro bids, and whether demand side or other generation resources could reduce the overall cost and need for the transmission network upgrades.[165]

140. Among the other parties that raise transmission concerns, CEC argues that the estimated $2.2 billion in transmission upgrades for the Denver Metro area is "shocking" and notes that this current estimate is almost nine times larger than the estimate provided in Phase I. CEC

[162] HE 107 p. 50-51
[163] Staff's Comments, pp. 43-44 (citing Appendix Q to the 120-Day Report).
[164] Staff's Comments, p. 40.
[165] Staff's Comments, pp. 39-41.

asserts that this change fundamentally alters the facts the Commission and stakeholders relied on in Phase I.[166] UCA similarly argues that in the Preferred Portfolio Public Service intertwines generation and transmission projects to provide a circular basis for one another, which significantly expands Company ownership, costs, and capacity beyond what was contemplated in the Phase I Settlement.[167]

141. In the 120-Day Report, the Company cites several factors driving the need for large investments in the Denver Metro area, including population growth, the scale and location of new generation that the Company is acquiring in the Preferred Portfolio, and the lack of cost-effective bids in the Denver Metro area.[168] In its Response Comments, Public Service recognizes that "additional work remains to better integrate transmission and generation planning" but argues against the idea that material cost savings could be obtained with further analysis of the transmission costs or tweaks to the resource portfolio.[169] As support, the Company notes that a 30 percent reduction in the size of the resource portfolio only results in a 20 percent reduction in modeled transmission costs.[170]

142. The large and unexpected costs of the transmission investments, the timing of the investments compared to the associated generation, and the analysis that resulted in the proposed transmission investments all support the selection of the Alternative Portfolio. The costs associated with curtailments is discussed above, but the UPP creates a timing mismatch in which the majority of the transmission resources will be put into service years after the generation resources. In addition, we share Staff's questions as to whether alternatives exist that could reduce

[166] CEC's Comments, pp. 5-7.
[167] UCA's Comments, pp. 11-15.
[168] 120-Day Report, pp. 131-32.
[169] Public Service's Response Comments, pp. 68-69.
[170] Public Service's Response Comments, p. 69.

the overall costs and need for the network upgrades. While we cannot determine on this record whether the transmission network upgrades in the Denver Metro area will be necessary in the future,[171] the Alternative Portfolio defers certain resource acquisitions. At the very least, the deferrals provide more opportunities to further evaluate the proposed transmission network upgrades and enable the Commission – and Colorado as a whole – to have greater confidence that the acquisition of new resources minimizes transmission investments and is in the public interest.

6. Conclusion

143. Granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio instead of the UPP will likely reduce costs to customers, especially when the Commission considers costs more generally. Such costs include those that are likely to result from the curtailments that the model fails to capture and the potential future costs associated with Company-owned gas resources in the UPP (*e.g.*, decommissioning). At the same time, the Alternative Portfolio is just as reliable as the UPP, and perhaps more so. While the modeling shows that the UPP achieves greater emissions reductions than the Alternative Portfolio, the Alternative Portfolio still exceeds the state's ambitious clean energy targets, while leaving open the possibility for more cost effective emission reductions in the future. Furthermore, the emissions reductions in the UPP, and especially the interim emissions reductions, appear to be optimistic given the likely impact of curtailments that the modeling presented in the 120-Day Report does not fully incorporate. Finally, pursing a smaller, more tailored portfolio of resources is necessary for the public interest because it creates an opportunity to investigate how to better optimize transmission upgrades during resource selection and provides more opportunities to take advantage of

[171] While the estimated cost of the transmission investments is still quite large in Alternative Plan, it is approximately $397 million less than the associated transmission investments in the UPP ($2,353 - $1,956 = $397). (*Compare* Public Service's Response Comments, p. 9, *with* 120-Day Report (Appendix S) Rev. 1, p. 26.)

developing technologies that might reduce or eliminate investments in traditional generation and transmission assets. Given the point in this Proceeding in which the significantly higher transmission costs were disclosed and the opportunity to take advantage of other technologies to limit ratepayer expenses, including the UPP in the approved CEP cannot be found to be in the public interest, as the UPP leaves too many unanswered questions and opportunities for optimization still on the table. As discussed throughout this decision, modifying the CEP by including the Alternative Portfolio is necessary to ensure the plan is in the public interest.

144. To reach an approved CEP that meets Colorado's needs, we find that modification of the presented CEP to include the Alternative Portfolio is necessary to ensure the approved CEP is in the public interest. With its CEP activities—including the Coal Action Plan that is critical for reducing emissions—and the plans for workforce transition and community assistance, the modified CEP moves Colorado significantly forward in its clean energy transition.

F. Transmission

1. Phase II Changes in Transmission Investments

145. In Phase I of this Proceeding, Public Service explained that it would need to make transmission investments in four areas to accommodate the new generating resources to be procured: 1) Denver Metro network upgrades, 2) grid strength reinforcement, 3) reactive power/voltage support, and 4) generator interconnections. At that time, Public Service provided a "preliminary and illustrative" cost estimate of $250 million for the Denver Metro upgrades, and a "rough" estimate of the combined costs for voltage support and grid strength of $150 to $250 million.[172]

[172] Hearing Exhibit 107, Direct Testimony and Attachments of Hari Singh, pp. 50-59.

146. In the 120-Day Report, the Company states that the transmission analysis it conducted to support the CEP is its most thorough transmission analysis for an ERP ever, involving numerous power flow studies, scenario modeling and "tabletop exercises" to develop project scoping and cost estimates. The Company states that 1) the scale and (largely remote) location of the new generation the Company will procure via this ERP, 2) the planned generation retirements the ERP entails, and 3) the lack of bids for new or existing generation located within the Denver Metro area transmission constraint all combine to require significant evolution of, and investment in, the transmission system to maintain reliable delivery of power to load centers.[173]

147. More specifically, the Company states that its existing substations lack the space for expansions necessary to eliminate overloads and expand the system's capacity, and that it has identified significant needs for new substations and new transmission lines. Moreover, it states that siting, permitting, and the need for extensive undergrounding in the Denver Metro area add cost and complexity to many of the network upgrade projects it has identified. Given these siting challenges, the Company states that its planning approach has been to create long-term ratepayer value by considering not only what upgrades are needed for its Preferred Portfolio, but also designing to accommodate future renewable development and growth in electricity demand.[174]

148. The Phase II cost estimates for grid strength/voltage support and the MVLE are consistent with the estimates for those costs in Phase I of this Proceeding. However, the Company adds a new, previously unreported category of transmission investments in Phase II—the San Luis Valley (SLV) network upgrades with an estimated cost of $176 million. In addition, in Phase II the estimated costs of the Denver Metro upgrades increase from $250 million to $2,146 million.

[173] 120-Day Report, pp. 128-134.
[174] 120-Day Report, pp. 128-134.

While Public Service asserts that its Phase II costs are not CPCN-level estimates, the Company states that its "process improvements" give it a higher confidence in these estimates than in those provided in previous ERPs.[175]

149. The Company claims that the need for Metro Denver upgrades have greatly expanded in Phase II and that the Phase II analysis identified substantial network upgrades needed within the SLV as well. The Company states that "[w]hile the smaller portfolio of transmission projects contemplated in Phase I may have alleviated transmission overloads within a short time window, the customer value of a smaller transmission portfolio would be quickly overwhelmed by additional load growth and resource acquisitions, requiring costly and difficult upgrades to new transmission facilities."[176] The Company stated reasons for the higher costs of the transmission investments include the following: siting and permitting challenges and the need for undergrounding many facilities in the Denver Metro area, the scale and location of new generation that will be acquired in this Proceeding, and the lack of cost-effective generation bids in the Denver Metro area.[177]

2. Party Comments

150. Staff reiterates that Public Service's transmission power flow analysis—conducted at the tail end of the Phase II modeling—estimates that almost $3 billion in transmission investment is needed to support the Preferred Portfolio (in addition to the approximately $1.7 billion investment recently approved in the CPP). Staff states that this estimated $4.5 billion in transmission investments is perhaps "Staff's largest concern with the Company's Preferred

[175] 120-Day Report (Appendix Q), p. 3.
[176] 120-Day Report (Appendix Q), p. 11.
[177] 120-Day Report (Appendix Q), p. 12.

Plan."[178] Staff reviews the Company's explanation of the necessary transmission upgrades but states that it is left with more questions than answers. Staff recommends that 1) the Commission make clear that "the Commission is in no way approving the transmission projects presented and described in the Report;" 2) the Commission add consideration of improved integration between transmission and resource planning and modeling to the recently-opened transmission pre-rulemaking docket 23M-0472E; 3) the Commission consider directing the Company to file a standalone transmission planning application; and 4) that the Commission consider options for implementing an independent transmission monitor.[179]

151. Staff acknowledges the concern that some of its recommendations could further delay transmission investments needed to deliver renewable energy. Given that many of the ISDs for the transmission investments are in 2029 and 2030, however, Staff argues that such delays might be avoidable.[180]

152. CEO, UCA, and CEC similarly criticize the transmission network upgrade proposals the Company presents in the 120-Day Report. For example, CEO recommends the Commission clarify that it is not providing a presumption of prudence on the proposed Denver Metro transmission network upgrades until additional information is provided. Specifically, CEO recommends the Company provide more information on the degree to which upgrades are necessary for reliability, as compared to planning for future growth.[181] UCA complains that the Company did not inform the Commission in the CPP proceeding that additional billions of dollars would be needed to deliver power from the CEP and states that had it

[178] Staff's Comments, p. 8.
[179] Staff's Comments, pp. 44-45.
[180] Staff's Comments, p. 45.
[181] CEO's Comments, pp. 29-30.

been aware of the magnitude of the transmission upgrade needs the Company now claims, it would have approached the proceeding differently.[182]

153. In contrast, other parties such as CIEA and COSSA/SEIA generally support the Company's proposed transmission investments.[183] In fact, COSSA/SEIA suggests that the transmission investments should be designed to accommodate continued growth in renewable energy development.[184]

154. In its Response Comments, Public Service maintains that transmission projects will be necessary for any generation portfolio to achieve the aggressive emission reductions the State requires.[185] In response to party comments recommending that the Commission not provide final approval of the network upgrade projects, the Company notes that it has not sought such approval, and reiterates its recommendation that the Commission schedule a Commissioners' Information Meeting (CIM) on CEP-related transmission in the first quarter of 2024 where the Company can further detail its broader transmission plans and analysis, and answer Commissioner questions. Following this, the Commission and parties can vet transmission projects through CPCN filings.[186]

155. The Company urges the Commission to deny the Staff recommendations to require a transmission planning proceeding and an independent transmission monitor. Public Service claims that "[t]hese recommendations are vague and would unnecessarily slow down the energy transition by requiring parties to expend valuable time and resources on processes with little, if any, incremental benefit."[187]

[182] UCA's Comments, pp. 14-15.
[183] *See, e.g.*, CIEA's Comments, pp. 19-20.
[184] COSSA/SEIA's Comments, pp. 20-21.
[185] Public Service's Response Comments, pp. 65-66.
[186] Public Service's Response Comments, pp. 66-67.
[187] Public Service's Response Comments, pp. 67-68.

156. The Company expresses strong disagreement with Staff's suggestion that generating resources should be delayed to future ERPs in recognition of the time it will take to put the new transmission assets into service (and the likely curtailment this will cause). The Company argues that the State's policy objectives do not allow for this delay, and it encourages the Commission to approve the UPP now. It claims that delaying approval of generation assets will only result in increased bid prices for generation and increase both the cost and siting difficulties for transmission.[188] Public Service further argues that using tools such as curtailment and redispatch in the short term as transmission buildout is completed is superior to delaying the acquisition of resources.[189]

157. Responding to party arguments that some of the transmission upgrades are unnecessary, the Company notes that none of these parties conducted detailed transmission planning analyses and refers to their contentions as conjecture. The Company asserts that the transmission portfolio is a reasonable set of solutions and states that it sought to upgrade existing transmission facilities wherever possible instead of constructing new greenfield transmission lines.[190]

3. Findings and Conclusions regarding Transmission

158. We share the serious concerns expressed by parties regarding the large, unexpected cost increases in transmission investments. After nearly three years of process, it was incredibly frustrating to see such a major failure of planning and estimating come to light so late in this Proceeding, upending the understandings of this Commission and many of the parties about the cost to integrate resources associated with this solicitation. Public Service will need to improve

[188] Public Service's Response Comments, pp. 72-73.
[189] Public Service's Response Comments, pp. 73-74.
[190] Public Service's Response Comments, pp. 70-72.

its transmission modelling and cost estimation processes in in future ERP proceedings to allow the Commission and relevant stakeholders a better ability to assess the critical links between generation and transmission resources. As noted above, the concern around transmission that arose in Phase II of this Proceeding was one of the factors that compelled us to select a smaller, more tailored resource portfolio.

159. In addition, the Commission emphasizes that the proposed transmission network upgrades, grid strength reinforcements, and reactive power/voltage support investments presented in the 120-Day Report are not part of the approved CEP. We are neither approving (or denying) these transmission actions here nor entitling the investments to any sort of presumption of prudence (or prejudice). Substantially more process will be required to fully assess the need for, alternatives to, and cost of remedial actions on the transmission grid in light of significant transition that this Proceeding initiates. Not only does the Company note that it is not seeking approval of those actions here, but the Commission has made clear it is modifying the CEP such that these actions are still to-be-determined with possible alternative solutions.

160. Moreover, as presented, the transmission network upgrades appear designed to accommodate future renewable development and growth in electricity demand, not *just* the CEP and its emissions reduction goals. Likewise, the alleged need for some of the proposed transmission upgrades may simply be the result of an aging system and changing dynamics. Though prudency only attaches to the "approved CEP," Company filings continue to emphasize that the transmission network upgrades presented here are not part of its CEP.

161. In the context of the shocking cost increases associated with the new transmission and concerns regarding the analysis and vetting of the proposed alternatives to the transmission investments, the Commission agrees with Staff that we simply do not have enough information or

reliable modeling to authorize the spending on another $2.8 billion in transmission investments at the current time.[191] While the Commission recognizes that a prudency determination was not sought by the Company in this Proceeding, we are wary to approve a suite of resources that all but lock in the future need for significant additional future system expenses without first vetting alternatives to mitigate those costs. The Commission needs to see a more holistic picture of the various transmission projects arising from this Proceeding, including what investments are necessary and how the various transmission investments work together with other system requirements and constraints. This additional review of the proposed transmission projects is necessary even if Rule 3206 technically would not require a CPCN for some of the individual transmission projects in other circumstances. Accordingly, we waive Rule 3206 as to the transmission projects arising from this Proceeding; we emphasize that it is incumbent upon Public Service to provide a fulsome and comprehensive description of all transmission projects necessary to accommodate power delivery and maintain reliable service from the approved CEP. Thus, the Company is requested to bring forward one or more CPCN or other filings regarding transmission projects raised in this Proceeding. However, and particularly given our emphasis that selecting the Alternative Portfolio presents the opportunity that not every transmission project raised will ultimately be pursued, we leave it to the Company's discretion on how best to present this type of analysis to the Commission; *i.e.,* both in timing and type of filings made, but also with regard to the number or combination of filings.

162. The Commission does not oppose the Company's offer in its Response Comments to make a presentation on expected transmission requirements in a CIM. As a general matter, we are particularly interested in additional information regarding the differences in transmission plans

[191] Staff's Comments, p. 45.

between the UPP and the Alternative Portfolio as well as any explanation the Company can provide regarding the failure to better anticipate the significant transmission needs in the Denver Metro area. Likewise, the Commission is interested in learning from Public Service how the Company's planning processes will improve and any innovative ways to approach future ERP proceedings so that the optimization of costs includes transmission investments, and to avoid similar major discrepancies between Phase I and Phase II expectations presented in modeling. Nevertheless, we recognize that when the Company proposed the transmission CIM, it did so in the context of the UPP rather than the Alternative Portfolio. Given the significant changes associated with the Alternative Portfolio and timing concerns with the upcoming filing of the 2024 JTS, we refrain from directing a transmission CIM at this time but invite the Company to determine the appropriate time and forum to address our concerns.

163. In addition, we find merit in Staff's proposal that the scope of Proceeding No. 23M-0472E (*i.e.*, regarding review of the provisions addressing transmission CPCN and planning in the Commission's Rules Regulating Electric Utilities, 4 CCR 723-3, in anticipation of future rulemaking) should be specifically defined to include consideration of improved processes for integrating transmission planning into generation resource plan proceedings and modeling. It is reasonable to expect that a previously unknown $2 billion in additional expenses is an important variable to optimize around by reevaluating what different resource acquisition decisions would or could have been made to bring the entire portfolio of resource and transmission needs to a reasonable and optimized cost for ratepayers. As appropriate we will address these considerations in the context of Proceeding No. 23M-0472E, including through future order in that proceeding.[192]

[192] Staff and interested stakeholders are encouraged to bring forward proposals in the context of that proceeding. The Commission will address any necessary direction directly in the context of the pre-rulemaking proceeding.

164. We similarly find merit in Staff's recommendation to consider options for implementing an independent transmission analyst. The Commission sees value in having some independent transmission and power flow modeling expertise among Staff, CEO, and UCA with which the Company could collaborate. The presence of such outside expertise could help accelerate approvals and lessen the overwhelmingly negative reactions of "surprises," such as the $2.2 billion in transmission network upgrades for the Denver Metro area. We see the primary role of this independent transmission analyst as building up the analytical capabilities of parties, particularly Staff, UCA, and CEO, regarding power flow modeling and other transmission issues.

165. Accordingly, we direct Staff to initiate a stakeholder process with UCA and CEO and in conferral with Public Service. The objective of the stakeholder process would be for Staff to bring forward a scope of work for hiring an independent transmission analyst. While we will leave it to the stakeholders to work through the details, this scope of work could be based on the IE contracting approach the Commission uses in ERP proceedings in which the Company contracts with the outside expert. Our expectation is that the analyst would work integrally with Staff. Ultimately, however, the independent transmission analyst must maintain independence from the Company.

166. Regarding timing, Staff should bring forward the proposed scope of work as soon as reasonably feasible but no later than through initial filings at the commencement of the 2024 JTS proceeding. Ideally, the independent transmission analyst could assist with the modeling in Phase I of the 2024 JTS. It would be ideal in Phase I of the process to have the help of an expert third-party to identify approximate quantities of certain resource types in targeted geographic areas to test assumptions about total costs for different portfolios, inclusive of both generation and transmission costs. We acknowledge the short timeframe this creates but find that time is of the

essence to ensure that the relevant state agencies have this type of expertise available during Phase I of the 2024 JTS to inform the parameters of the Phase II portfolios, given the shortcomings of this Proceeding.

167. As should be evident from our decisions on items such as the selection of the Alternative Portfolio and the directive for Staff to produce a scope of work for an independent transmission analyst, it is our expectation that the Company will look for better ways to model and analyze transmission costs in Phase I of the 2024 JTS. Part of these efforts should focus on mechanisms to provide reliable electrical service through dynamically managing both supply resource and demand resources—as opposed to simply building more generation and transmission resources.

168. We aspire for the independent transmission analyst discussed above to be engaged during Phase I of the 2024 JTS to bolster the analytical capabilities of Staff, CEO, and UCA regarding the integration of transmission and generation resources. However, given the possibility that the independent transmission analyst cannot be engaged in time for Phase I, as a backstop we direct Public Service to include certain portfolios in its direct case. Specifically, Public Service must present—at a bare minimum—one or more portfolios that examine minimizing transmission costs by increasing resources interconnecting in the Denver Metro area or using capacity on existing transmission lines, including capacity that will become available as thermal generating units retire. Broadly communicating the geographic areas for resource development anticipated to minimize transmission costs could also increase the likelihood of bidders to provide additional options in these target areas.

G. Performance Incentive Mechanisms

1. Background and Party Comments

169. After the filing of the 120-Day Report, in Decision No. C23-0672-I[193] the Commission directed the Company to submit comments outlining a potential symmetric risk sharing mechanism that would apply to Company-owned projects. The goal of this project-specific mechanism would be to better align customer and utility incentives, treat Company-owned generation projects in ways that are at least somewhat closer to the risks that are routinely imposed on IPP projects, and to ensure reasonable costs for customers.[194] While the Commission required a response from Public Service, it also invited comments from the intervenors.[195]

170. On October 20, 2023, Public Service filed its Response to Decision No. C23-0672-I. Staff similarly filed a proposal on October 20, 2023, which UCA and CEC joined.

171. Public Service proposes two complimentary risk-sharing proposals or PIMs, with possible variations for both PIMs. The first is a cost to construct PIM intended to incentivize the Company to complete projects within its estimated capital expenditures that formed the basis of its Phase II bids. The Company proposes either (1) a dead band with sharing approach, or (2) a fixed capital cost approach. For either of these two approaches, the Company recognizes that the Commission could implement the PIM on either a project specific basis or on a portfolio basis.[196]

172. The second PIM is an "operational performance" PIM modeled after the Commission's suggested Levelized Energy Cost (LEC) metric identified in Appendix P to the 120-Day Report. Noting that the committed energy and weather adjustment provisions of PPA

[193] Issued October 6, 2023.
[194] Decision No. C23-0672-I, p. 3.
[195] Decision No. C23-0672-I, p. 4.
[196] Response to Decision No. C23-0672-I, pp. 6-7.

allow IPPs some flexibility in how much energy their projects produce, the Company argues that a 15 percent dead band around the Appendix P LEC is appropriate.[197] The Company further argues that the operational PIM should not seek to manage curtailments but that this is better addressed in the emissions reduction PIM.[198] In fact, the Company argues that any operational PIM should include curtailed volumes in the calculation of the LEC in part because this avoids creating a perverse incentive to favor Company-owned generation when determining which units to curtail.[199]

173. The Company asserts that the combination of these two PIMs should meet the Commission's expectation regarding cost discipline regarding both capital investment and operational performance.[200]

174. Under Staff's proposed PIM for utility-owned generation, Public Service would be required to recover the costs of Company-owned renewable generation assets entirely through the electric commodity adjustment (ECA) as opposed to base rates.[201]

175. Other intervenors suggest various other types of PIMs in their comments to the 120-Day Report. For example, Boulder's suggestions include a PIM for Company-owned projects that would use as a baseline the cost of seemingly lower priced bids as well as a PIM to address the capacity factors for gas resources.[202] COSSA/SEIA suggests that the Commission consider deploying a PIM that would incentivize the on-time construction and deployment of new

[197] Response to Decision No. C23-0672-I, p. 11.
[198] Response to Decision No. C23-0672-I, pp. 12-13.
[199] Response to Decision No. C23-0672-I, p. 13.
[200] Response to Decision No. C23-0672-I, pp. 1-2.
[201] Staff Response to Risk Sharing Mechanism, p. 14.
[202] Boulder's Comments, pp. 14-15.

transmission assets.[203] Conservation Coalition in turn proposes a mechanism in which the Company would bear any incremental costs for hydrogen conversion of its gas plants.[204]

176. In its Response Comments, the Company appears to argue that the cost to construct PIM should only be a fixed capital cost approach based on the total portfolio. Without much explanation, Public Service states that to facilitate approval of a PIM framework in this Proceeding, there should be no dead band for the construction capital cost PIM. Instead, the baseline should be set at the approved portfolio capital budget/point cost estimate.[205]

177. For the operational PIM, the Company argues in its Response Comments that the baseline should be adjusted to exclude the effect of construction capital expenditures in order to avoid such capital expenditures being subject to both PIMs. Public Service states that this is necessary to avoid double penalty or double reward.[206] In addition, the Company states that the evaluation period for projects subject to the operational PIM should occur on three-year intervals beginning with the first through third full calendar years of project operation. As an example, for a project with a commercial operation date of September 30, 2026, the evaluation period for the operational performance PIM would begin January 1, 2027, and extend through December 31, 2029. Public Service argues that this promotes administrative efficiency and better addresses annual variation in weather, maintenance patterns and other performance drivers.[207]

178. In contrast, Public Service vehemently opposes Staff's proposal, stating that "[t]he magnitude and ramifications of this proposed sea change are difficult to overstate."[208] Public Service asserts that Staff's PIM would "essentially deregulate generation in the state" in

[203] COSSA/SEIA's Comments, pp. 20-21.
[204] Conservation Coalition's Comments, pp. 16-17.
[205] Public Service's Response Comments, pp. 81-82.
[206] Public Service's Response Comments, p. 82.
[207] Public Service's Response Comments, p. 82.
[208] Public Service's Response Comments, p. 83.

that it would reconstitute the Company as an IPP in all but name.[209] The Company argues that Staff's proposal would increase the risks conferred to the Company with little incremental benefit and no opportunity to price that risk into its bids. Public Service asserts that, if implemented, Staff's proposal "would require the Company to reassess its project commitments, increasing the cost and delaying the delivery of this plan, or whatever is left of it."[210]

179. On December 19, 2023, Public Service filed its Response to Decision No. C23-0841-I, providing additional point costs and capacity factors data in connection with the Alternative Portfolio and setting forth the Company's proposed sharing percentages for the operational PIM in a non-confidential format.

2. Findings and Conclusions

180. The Commission appreciates that the Company has "sharpened its pencil" and is willing to "stand behind its pricing and performance metrics as bid."[211] Given the significant amount of Company-owned generation projects in the portfolio of resources Public Service will acquire,[212] this confidence and willingness to share risks is an important component of our decision to move forward with the Alternative Portfolio. In other contexts, costs, performance, or scheduling issues have increased costs for customers relative to the initial estimates the Company provided, and material changes to the cost and performance metrics of a project could impact the justification of the need determinations made in the ERP process.[213] More generally, competitive solicitation is the lynchpin of Colorado's ERP process, and a successful competitive solicitation

[209] Public Service's Response Comments, p. 83.
[210] Public Service's Response Comments, p. 86.
[211] Response to Decision No. C23-0672-I, p. 4.
[212] Of the 5,835 MW that the Alternative Portfolio contemplates acquiring, Public Service would own 53.7 percent of the capacity resources and 67.3 percent of the energy resources. (120-Day Report (Appendix S), Rev. 1, p. 26.)
[213] *See* Decision No. C23-0672-I, pp. 2-3.

relies upon some degree of certainty that, after winning at a lower price, bidders will not be able to materially increase the price of their bids without consequences. To date, the Commission has not had a mechanism in place to hold the Company to their bids and performance, in a similar way to the IPP contracts, which has increasingly become a point of concern. In Phase I of this Proceeding, the Company put forth a plan to convert the Brush Coal Plant to burn natural gas at a capital cost of $44 million. The Commission and parties relied upon the information provided by the Company to make decisions in Phase I of this Proceeding, broadly considered the Company's Coal Action Plan, which was agreed to be carried forward into the Phase II modeling. Several months later, the Company put forth a CPCN application to complete the conversion at the significantly increased cost of $85 million. The Commission finds a compelling need to ensure that the pricing relied upon during this Proceeding will not be significantly altered after the fact without a meaningful sharing of risk with the Company. The Company-ownership PIMs that Public Service proposes help ensure that the Commission is making informed resource acquisition decisions, promoting fairness amongst the bidders and the Company, and providing necessary protections to ratepayers.[214]

181. Accordingly, as part of the Commission's approval of the planned acquisition of Company-owned generations projects consistent with the Alternative Portfolio, we adopt a cost to construct PIM and an operational PIM for all Company-owned generation projects arising from this Proceeding.[215] These cost to construct and operational PIM are based on the Company's proposals, subject to the modifications detailed below.

[214] *See* Decision No. C23-0672-I, pp. 2-3.

[215] The cost to construct PIM applies to all Company-owned generation projects from this Proceeding, including Bid 1029. As set forth below, however, the operational PIM only applies to Company-owned LEC projects.

a. Cost to Construct PIM

182. Starting with the cost to construct PIM, we reject the Company's arguments that the cost to construct PIM should be applied on a portfolio basis. Rather, the cost to construct PIM shall be a project-specific PIM for each Company-owned project in the Alternative Portfolio. Applying this PIM on a portfolio level would be inconsistent with how IPP bids are treated and contrary to the underlying principles of the competitive solicitation that each project must stand on its own.

183. The baseline for each cost to construct PIM will be the point cost for capital costs to construct the particular generation project that was used in the Company's Phase II bid. In its Response to Decision No. C23-0672-I, Public Service states that "each Company-owned bid has a point cost for capital cost to construct that can serve as a baseline for PIM evaluation purposes."[216] During the course of Phase II, the Company provided the point costs for all relevant Company-owned projects.

184. Under the cost to construct PIM, there would be a five percent dead band around the baseline in which Public Service earns no incentive or disincentive. Outside of the five percent dead band, however, the Company and ratepayers would share any cost overruns or savings based on three symmetrical tiers. Specifically, for a total variance of more than 5.0 percent through 10.0 percent above or below the baseline, 40 percent of the cost overruns or savings would be allocated to Public Service. For a variance of more than 10.0 percent through 15.0 percent above or below the baseline, 50 percent of the cost overruns or savings would be allocated to Public Service. For any variance above or below 15.0 percent of the baseline, 60 percent of the cost overruns or savings would be allocated to Public Service.

[216] Response to Decision No. C23-0672-I, p. 6.

185. The sharing percentage will be applied to the overage and not on the total project amount. Also, there will be no deduction due to the 5 percent dead band or any other previous tiers. For example, if a project with a $100 million point cost is actually constructed for $114 million, Public Service would incur a $7 million disincentive; *i.e.,* the 14 percent overage means that 50 percent of additional costs are allocated to Public Service (50 percent of $14 million is $7 million). The same calculation would be used if Public Service was able to construct the project for only $86 million. In that scenario, the Company would earn a $7 million incentive. Resolution of the appropriate PIM assessment (*i.e.* the calculation of any incentive or disincentive) will occur in the first rate case following the ISD of the relevant generation project.

b. Operational PIM

186. Turning to the operational PIM, the baseline will be the LEC for the relevant project set forth in the corrected Appendix P. The operational PIM will be applied on a project-specific basis. Except for LCC-based projects like standalone storage and gas, the operational PIM will apply to all Company-owned generation arising from this Proceeding. Regarding the exclusion of LCC-based projects, we find persuasive the Company's argument that including such project could have an unintended consequence of incentivizing the overuse of dispatchable resources in order to avoid penalties or to accrue incentives.[217]

187. The Commission rejects the 15 percent dead band that Public Service proposes for the operational PIM and will replace it with a 5 percent dead band around the LEC baseline. This narrower dead band is supported by—among other things—CIEA's Comments. CIEA asserts that the Company either exaggerates or obscures the true costs and risks of its proposal when compared to PPA arrangements. CIEA points out that IPPs have no dead band around their bid

[217] Response to Decision No. C23-0672-I, p. 12.

price and suggests that the Company should not have the benefit of a dead band either.[218] While we do not agree that removing the dead band altogether is appropriate, we agree with CIEA that the intent of the PIM is to set the Company's bidding risk on par with IPPs more readily. Establishing the mechanism here with a narrower dead band than proposed by the Company better aligns these goals.

188. Aside from the narrower dead band, the basic calculation structure for assessing the incentive or disincentive under the operational PIM would generally match the Company's proposal. Specifically, for variances of more than 5 percent through 10 percent above or below the baseline, 20 percent of the costs or savings would be allocated to Public Service. For variances of more than 10 percent through 15 percent above or below the baseline, 30 percent of the costs or savings would be allocated to Public Service. For variances of more than 15 percent through 20 percent above or below the baseline, 40 percent of the costs or savings would be allocated to Public Service. For variances of more than 20 percent through 25 percent above or below the baseline, 50 percent of the costs or savings would be allocated to Public Service. And finally, for any variance more than 25 percent above or below the baseline, 60 percent of the costs or savings would be allocated to Public Service.[219]

189. Regarding the timing of performance evaluations, the Commission agrees with the Company that performance evaluation for projects should be conducted on a three-year rolling average after the third full operational year is complete and on a similar cadence thereafter.[220]

[218] CIEA's Comments (Attachment A), p. 5-6.
[219] *See* Public Service's Response to Decision No. C23-0841, pp. 2-3.
[220] In its Response Comments, Public Service provides the following example of this timing: "As an example, for a project with a commercial operation date of September 30, 2026, the evaluation period for the operational performance PIM would begin January 1, 2027 and extend through December 31, 2029." (Public Service's Response Comments, p. 82).

This approach will stagger the performance reviews so that a subset of projects (*e.g.*, all those with 2026 ISDs) is evaluated each year.

190. We similarly agree with Public Service's arguments that the baseline of the operational PIM should be adjusted to exclude the effect of construction capital expenditures in order to avoid such capital expenditures being subject to both PIMs.[221] Excluding the effect of construction capital expenditures is necessary to avoid double penalty or double reward.

191. In connection with the establishment of the operational PIM, all projects subject to the operational PIM in this Proceeding will receive cost recovery through the appropriate rider (RESA or ECA) from the ISD of the project until the project is rolled into base rates.

192. While we direct that the operational PIM as described above apply to all Company-owned LEC projects arising from this Proceeding, we recognize that certain considerations warrant further exploration in future proceedings. For instance, we invite interested stakeholders and the Company to explore whether an operational PIM could be crafted in which the baseline is derived from the project's estimated capacity factor as opposed to the estimated LEC. This would essentially exclude factors such as the capital construction costs and the Company's estimated WACC. We welcome a more robust consideration of this approach in the upcoming 2024 JTS.

193. Similarly, we reiterate the importance of timing as a performance metric,[222] and have a strong interest in evaluating in the follow-on CPCN proceedings a mechanism to incentivize timely completion of Company-owned projects, in accordance with the timing anticipated in the modeling and bidding processes. For example, one possibility would be to commence the LEC

[221] Public Service's Response Comments, p. 82.
[222] *See* Decision No. C23-0672-I, ¶ 6.

calculations on the as-bid ISD of the Company-owned project. Thus, if the as-bid ISD of a project was May of 2026 but the project experienced delays and did not commence operations until October 2026, this six-month delay would decrease the project's achieved LEC as compared to the as-bid baseline LEC. While we do not adopt this structure as part of this Decision, we intend to evaluate in the follow on CPCN proceedings how best to align the Company's incentives regarding the completion of generation projects.

194. Regarding curtailments, we likewise intend to continue evaluating in the follow on CPCN proceedings how exactly the operational PIM should account for curtailments. To be clear, we do not intend for the operational PIM to somehow shift the risk of curtailments on to the Company. The issue of appropriately disincentivizing curtailments across the entire electrical system is better addressed elsewhere, including possibly through the emissions reduction PIM that the Phase I Decision contemplates. In this way, we largely agree with the Company's position that the operational PIM should not seek to manage curtailments.[223] Nevertheless, there are unresolved details regarding how to make the operational PIM appropriately indifferent to curtailments, and we intend to address these details in the follow on CPCN proceedings.

c. Extraordinary Circumstances

195. Finally, as to both the cost to construct PIM and the operational PIM, the Commission finds merit in Public Service's argument that the Company should be able to petition the Commission for relief in the event of extraordinary circumstances. In other words, Public Service can seek relief from the Commission for any amounts assessed to the Company under either the cost to construct PIM or the operational PIM, with the Company bearing the burden of establishing the existence of extraordinary circumstances and the impact of any such

[223] Response to Decision No. C23-0672-I, pp. 12-13.

circumstances on unit construction.[224] We clarify that the starting point for the definition of "extraordinary circumstances" could be similar to the definition of "force majeure" in the Model PPA for Wind and Solar.[225] That said, in the proceeding in which the Company attempts to establish the existence of extraordinary circumstances, the parties—including the Company—may advocate for modifications to the definition of "extraordinary circumstances" as appropriate, recognizing that Company-owned projects may not have identical extraordinary issues to the Model PPA.

d. Other proposed PIMs

196. We decline to implement Staff's proposed PIM in this Proceeding given our adoption of a cost to construct PIM and operational PIM. Nevertheless, we are intrigued about the possibilities offered by Staff's PIM. As Staff notes, under its PIM, cost recovery increases in direct proportion to the amount of renewable energy the assets produce while also tying cost recovery to Public Service's Phase II bids. Likewise, the PIM would account for both capital construction costs and performance of the assets.[226] The Commission sees Staff's PIM as a potential avenue to engage in performance based regulation (PBR) on a more fundamental level as opposed to simply overlaying PIMs on top of the standard cost of service ratemaking, providing a potential opportunity to realign utility incentives to benefit ratepayers.

197. Many of Public Service's arguments against Staff's PIM are focused on why it should not be applied to the Company-owned projects arising from this Proceeding. Arguments that Staff's PIM "moves the goalposts" after submission of Phase II bids and that Staff's PIM has many unresolved details might be legitimate as to this Proceeding but are far less

[224] Response to Decision No. C23-0672-I, p. 15.
[225] Hearing Exhibit 101, Attachment AKJ-3 (Volume 3.2), pp. 142-43.
[226] Staff's Response to Decision No. C23-0672-I, pp. 14-15.

persuasive regarding future implementation of Staff's PIM. Given the Commission's longstanding interest in PBR and the fact that the Commission has already approved a similar approach for one of Black Hills' wind projects,[227] the Company's claims that Staff's PIM would essentially deregulate generation in Colorado seem exaggerated.

198. The Commission intends to evaluate in the 2024 JTS whether Staff's PIM can be applied to the Company-owned projects arising from that proceeding. As such, we request that Public Service confer with Staff on its proposed PIM[228] prior to the 2024 JTS in an attempt to reach consensus. Regardless of the outcome of the conferral, we invite the parties in the 2024 JTS to raise this issue for our continued consideration.

199. As for the remaining proposed PIMs, including those that Boulder, COSSA/SEIA, and Conservation Coalition put forth in their comments, we decline to adopt these concepts in this Proceeding. Although the expedited nature of this Phase II process did not allow for the development of a robust record for these proposals, we invite the parties to consider bringing these proposals forward in the PIM stakeholder process that the Phase I Decision contemplates and through future proceedings.

H. The Sand Creek Massacre National Historic Site and Bid 1029

200. Bid 1029 is included in the Preferred Portfolio, the UPP, and the Alternative Portfolio and is a 500 MW Company-owned wind project with an in-service date of 2026. Although the Commission does not know the precise location of Bid 1029, it appears to be close to and possibly adversely impacts, the Sand Creek Massacre National Historic Site view shed.

[227] Staff recounts that Black Hills recovers the cost of the Peak View wind farm exclusively through the ECA and RESA for the first ten years of commercial operation. (Staff's Response to Decision No. C23-0672-I, p. 9).

[228] This conferral should include further evaluation of whether Staff's PIM could be modified to apply to LCC-based projects instead of only LEC-based projects.

201. On October 25, 2023, elder and tribal administrator Mr. William Walksalong of the Northern Cheyenne Nation spoke at the Commissioner's weekly business meeting. Through comments, tribal representatives requested that the Commission protect from energy development the viewshed of the Sand Creek Massacre National Historic Site given its sacred importance to several tribal nations. In addition, Mr. Walksalong asked that the Commission ensure that energy development not disturb any human remains or cultural artifacts from the area around the Sand Creek Massacre National Historic Site. Mr. Walksalong noted that the massacre spilled well-beyond the boundaries of the Sand Creek Massacre National Historic Site that Congress has designated. Consequently, he urged the Commission to require utilities and developers to consult tribal representatives as to how to proceed should remains or artifacts be discovered in the course of construction.

202. In its comments, Staff recommends the Commission not approve Bid 1029 as part of this Proceeding. Staff asserts that a preliminary viewshed analysis indicates that wind turbines from Bid 1029 might impact the Sand Creek Massacre National Historic Site's viewshed. Staff also ran its own modeling runs that forced the model to exclude Bid 1029 and suggests that the Commission could approve a 200 MW solar plant (Bid 375) or a 603 MW wind plant (Bid 1024) in place of Bid 1029.[229]

203. CEO also recognizes concerns regarding Bid 1029 but does not suggest that the Commission exclude it from the approved CEP. Rather, CEO recommends the Commission direct the Company to include additional information in subsequent CPCNs, including discussions between the Company and Tribal governments regarding the proposed projects, the status of those

[229] Staff's Comments, p. 58-59.

discussions, and any outcomes or results of such discussions.[230] CEO argues that approach will allow the Commission to take action in the instant proceeding consistent with the presentation by the Northern Cheyenne Nation and also rely on the existing CPCN process to consider alternatives and proposed impacts when making a determination on specific resource proposals.[231]

204. In its Response Comments, Public Service argues that Bid 1029 has "strong economics" and was included in almost all portfolios. Thus, the Company maintains that it would be premature to set this bid aside. Public Service does, however, acknowledge Staff's concerns and states that the identified impacts are important to work through and address. Indeed, the Company states that it is already engaged with these issues. Ultimately, Public Service asks that the Commission allow Bid 1029 to move forward and states that the Company would then provide an update on efforts to mitigate the impacts of concern in the follow on CPCN proceeding.[232]

205. The Commission agrees with the positions of Public Service and CEO and rejects Staff's proposal to exclude Bid 1029 from the approved CEP. We emphasize, however, that allowing the Company to include Bid 1029 in the Alternative Portfolio is in no way an approval of the project, which must necessarily be vetted through continued stakeholder and community considerations. In this vein, we adopt Public Service's suggestion to approve a backup bid for Bid 1029 so that the Company can pivot to a different project if stakeholder processes, including the Company's further discussions with the Northern Cheyenne Nation, do not resolve concerns. In addition, we adopt CEO's recommendation and direct Public Service to include additional information in subsequent CPCN proceedings, including discussions between the Company and Tribal governments.

[230] CEO's Comments, pp. 26.
[231] CEO's Comments, pp. 26.
[232] Public Service's Response Comments, pp. 23-24.

206. Resolution of this issue will require collaboration of the interested stakeholders, and we are encouraged by indications that Public Service is already engaging with the Northern Cheyenne Nation regarding Bid 1029. In this instance, Public Service needs to take the lead and work with interested stakeholders, including the Northern Cheyenne Nation, to address potential impacts to the Sand Creek Massacre National Historic Site.

207. As to the precise backup for Bid 1029, in its Response Comments Public Service recommends that the Commission approve Bid 1018. However, Bid 1018 is unavailable as a backup because it is located on the MVLE, which the Alternative Portfolio does not include. Ultimately, we permit the Company discretion to select an appropriate backup for Bid 1029 pursuant to the approved backup selection process set forth in this Decision. We note, however, that Bid 1016 (a 554 MW Company-owned wind bid) appears to be a good candidate.

I. Hayden Biomass

208. Bid 1031 is a 19 MW Company-owned biomass project that Public Service proposes as a Section 123 resource.[233] The proposed project is located near Hayden, Colorado to support workforce transition as part of the planned retirement of the Hayden coal units.[234]

209. Public Service states that it would employ 26 full-time employees, thus reducing workforce transition costs associated with the early retirement of the Hayden coal plants. Public Service further asserts that the project, which is anticipated to use primarily forest waste from fire prevention activities and debris from pine beetle outbreaks, is carbon neutral and would reduce air emissions, including particulate matter, carbon monoxide, volatile organics, and

[233] Public Service also states that it "complies with the spirit of" the portfolio development framework for HB 21-1324. (120-Day Report, p. 52).

[234] In its Response Comments, Public Service intentionally presents the bid name with the bid ID as public information.

nitrogen oxides.[235] In comparing the Preferred Portfolio with the Hayden biomass project to a reoptimized portfolio without the project, the portfolio excluding biomass adds 19 MW gas and 200 MW solar and is $257 million less in PVRR.[236]

1. Party Comments

210. The Labor Interests argue that the Hayden biomass project should belong in any Commission-approved portfolio, listing its benefits as including 26 well-paid jobs and a high total BVEM rating for its construction phase. The Labor Interests add that the Hayden biomass unit represents an innovative technology under both Section 123 and HB 21-1324, noting that wind and solar projects have often dominated discussions about innovation despite patterns of low-paying jobs post-construction.[237]

211. CEO supports the inclusion of the Hayden biomass plant in the Commission-approved CEP primarily because of its just transition benefits. CEO acknowledges, however, that Public Service "does not provide information on the salaries or the estimated tax benefits" and requests that the Company provide more details about the public benefits of the project "so the Commission has a full record on which to make its Phase II decision."[238] CEO also notes the relatively high cost of the biomass plant, concluding that the Hayden biomass project increases the PVRR of the Preferred Portfolio by $257 million.[239] CEO recommends that if the Commission does not approve the Hayden Biomass project here, the Commission direct the Company to evaluate the project in future ERPs for additional consideration.[240]

[235] 120-Day Report, p. 40.
[236] 120-Day Report, p. 138.
[237] Labor Interests' Comments, pp. 11-14.
[238] CEO's Comments, p. 23.
[239] CEO's Comments, p. 22.
[240] CEO's Comments, pp. 17.

212. OJT endorses CEO's Comments as to the just transition issues, including the evaluation of the Hayden biomass project.[241] OJT opines that the biomass project would employ a third of the coal plant's current workforce, generate a "significant, though yet-unspecified, amount of property tax revenues," and create long-term supply chain jobs in the region for timber harvesting and processing.[242] However, OJT also requests that Public Service provide more specific information on the expected local economic and employment benefits, including information about jobs retained or created and property and other tax revenues generated.[243]

213. Public comments from entities such as the Moffat County Board of County Commissioners, the Routt County Board of County Commissioners, the City of Craig, Northwest Colorado Development Council, Colorado State Senator Dylan Roberts, and the Town Council and Mayor of Hayden also expressed support for the Hayden biomass project, citing the risk that not replacing the coal plant will lead to cascading effects in the form of losing high-paying jobs and reducing funding for important government services.

214. In contrast, certain other parties recommend the Commission reject the Hayden biomass project and potentially reconsider it in an alternative proceeding, mostly pointing to the upcoming 2024 JTS. For example, CEC asserts that the Company has not established that the project is the best solution for the Hayden community, nor that it is worth the additional expense or necessary for emissions reductions.[244]

215. Staff argues that the Hayden biomass project is very high cost and is overall uneconomic, with unclear information about jobs benefits and tax revenue replacement.

[241] OJT's Comments, p. 3.
[242] OJT's Comments, p. 6.
[243] *See* OJT's Comments, pp. 3, 6.
[244] CEC's Comments, pp. 13-14.

Staff asserts that the Hayden biomass plant is not designed as a closed-loop facility and thus will not enjoy access to a full production tax credit, meaning that the cost of the biomass unit presented in the 120-Day Report is artificially low. Staff states that it conferred with the Company, which agreed with this critique.[245] Staff also raises concerns that the Hayden biomass project is not sufficiently novel or scalable to be a Section 123 project.[246] Staff suggests that the Commission consider alternatives to the biomass facility in future proceedings.[247]

216. Similar to Staff, WRA raises concerns not only about cost, but also about environmental claims made about the Hayden biomass project. Referencing recent studies, WRA asserts that emissions from the harvesting stage strongly erode any potential emissions benefit, and inefficiencies mean electricity generation with woody biomass can be more carbon-intensive per MWh than coal-generated electricity.[248] WRA argues that Public Service's assertions about the Hayden biomass project being greenhouse gas neutral are incorrect as a matter of practice—biomass electricity generation produces carbon dioxide—and also that the Company has failed to provide information demonstrating that emissions released from combustion are less than would have been emitted without being converted to electrification, pursuant to § 40-2-124(1)(a)(IV).[249] Moreover, WRA states that the 120-Day Report provides insufficient information about planned forest management practices and leaves open the idea that other fuel would be used besides that from fire prevention and pine beetle kill.[250]

217. Like Staff and WRA, Conservation Coalition raises concerns that greenhouse gas emissions from the biomass project will exceed the Company's estimates. Conservation Coalition

[245] Staff's Comments, p. 53.
[246] Staff's Comments, pp. 51-52.
[247] Staff's Comments, p. 51.
[248] WRA's Comments, pp. 9-10.
[249] WRA's Comments, p. 11.
[250] WRA's Comments, p. 12.

argues that the Commission can consider additional measures for the Hayden community in the 2024 JTS, noting that the last unit at Hayden is not scheduled to retire until 2028.[251] Additionally, public comments from entities like 350 Colorado similarly urge the Commission to find other ways to meet just transition needs due to environmental risks associate with the proposed biomass project, including air pollutant emissions and the potential that salvage logging and deforestation activities may be required to meet fuel needs.

218. In its Response Comments, Public Service reiterates that the Hayden biomass project contributes to three policy objectives: developing clean firm dispatchable capacity with wildfire mitigation benefits, making progress towards emissions reduction goals, and providing just transition benefits. The Company states that not providing new workforce opportunities for communities affected by energy transition is "not a viable path."[252] However, Public Service also recognizes that questions about cost and tax credit eligibility are legitimate, and therefore proposes alternative procedural pathways, including conditional approval of the project with additional analysis in a follow-on CPCN filing or consideration within the Hayden JTP filing.[253]

2. Findings and Conclusions

219. In its Phase I Decision, the Commission approved provisions of the Phase I Settlement specifying that Public Service will make follow-on JTP filings for each area with an affected coal plant after the Phase II final decision.[254] For purposes of Phase II modeling, JTP costs will include costs associated with workforce transition and community assistance.

[251] Conservation Coalition's Comments, pp. 15-16.
[252] Public Service's Response Comments, p. 19.
[253] Public Service's Response Comments, pp. 19-20.
[254] Phase I Settlement, ¶ 109.

220. Regarding the Hayden 1 and Hayden 2 coal plants, the estimated costs of the community assistance is the projected lost property tax revenues for six years following retirement of the respective plant, but these costs may be offset by other investments in the community.[255]

221. The Commission takes seriously its role in supporting a just transition for workers and communities that are impacted by the closure of coal units as part of creating a cleaner energy system. The labors and skills of these communities helped propel Colorado's economy and the reliable electricity we have enjoyed for generations. We have a commitment to do what we can to ensure these communities are not left behind in the energy transition, and this might go beyond even the six-year commitment that was contemplated in the Phase I Settlement. Regarding the closures of Hayden 1 and Hayden 2, we recognize the transmission resources that will be made available in the near future as well as the potential expansion of these transmission resources into the western market. In short, the Commission is hopeful that there will be opportunities for resource development that benefit both local communities and ratepayers in general.

222. Nevertheless, we decline to approve the Hayden biomass project in this Proceeding. We do not have in front of us a complete proposal that allows us to determine whether the project is in the public interest. For example, we are concerned by Staff's assertion that the Company will not qualify for closed-loop biomass tax credits, which leaves the actual cost of the project uncertain, and we are troubled by the potential environmental impacts of the plant that WRA and others raise. Moreover, even CEO and OJT seem to acknowledge that the current proposal lacks important information regarding workforce transition and community benefits. The Hayden biomass project would cost ratepayers approximately $257 million in PVRR before upward

[255] Phase I Settlement, p. 19.

adjustments due to tax credit miscalculations, and this is for a relatively small 19 MW project that would replace what has been hundreds of MW of capacity from the Hayden coal plants.[256]

223. While we decline to approve the Hayden biomass project here, in the event Public Service develops clearer answers to the questions raised by parties about the environmental, financial, workforce, and community benefits of the plant, we encourage the Company to bring this or another just transition proposal forward for further consideration as part of the 2024 JTS. The 2024 JTS proceeding[257]—as opposed to the Hayden JTP or a standalone CPCN—will allow the Commission and stakeholder to evaluate the costs and benefits of the biomass project, if rebid, more holistically with other alternatives, including potentially other bids from IPPs that could provide similar tax, employment, and other benefits to the local community. We conclude that reconsidering this or other similar projects in a full competitive solicitation will be the best way to maximize benefits to both the Hayden community and to ratepayers more generally.

224. To effectuate this, Public Service shall confer with relevant stakeholders and determine whether it makes sense to bring forward the Hayden JTP within 120 days of the Phase II decision, consistent with approved provisions of the Phase I Settlement, or to postpone that filing. In conferral with settling parties, and particularly those affected by the potential Hayden JTP filing, since the Hayden Biomass project or other beneficial projects could potentially be reevaluated in the 2024 JTS, we permit flexibility on whether the Hayden JTP should be filed 120 days following the Phase II decision or at a later date.

[256] *See* CEO's Comments, p. 22 (comparing Preferred Portfolio with Hayden biomass to the Preferred Portfolio without Hayden biomass).

[257] The Commission emphasizes that the primary focus of the 2024 JTS is the replacement of Unit 3 and the corresponding impacts to the Pueblo community. Nevertheless, as an interim ERP the 2024 JTS also provides an opportunity to evaluate more holistically the various resource opportunities in the Hayden community.

J. Backup Bids

225. In the 120-Day Report, the Company proposes three tools to mitigate the risks associated with potential project failure: extensive due diligence, right of first offer (ROFO), and backup bids. Public Service further notes that the 2024 JTS allows for a more rapid opportunity to course correct than the standard four-year ERP cycle typically provides.[258] Regarding the backup bids, Public Service states that these bids are intended to be pre-approved by the Commission as a set of projects to be "next in line" to replace a project in the approved portfolio if it fails.

1. Party Comments

226. Staff is generally supportive of the establishment of a pool of back-up resources. However, Staff is concerned that approving a backup pool of bids that includes both Company-owned and PPA bids may create perverse incentives for the Company in negotiating projects. For instance, Staff questions whether the Company's PPA negotiations with an IPP would be impacted if the IPP project would be replaced with a Company-owned project.[259]

227. Staff recommends that the Commission consider a back-up bid replacement process in which additional process is required for Company-owned backup bids. If a failed project is being replaced by a PPA project, the Company should notify the Commission of such a failure and the steps it intends to take to address the failure, but the Company need not seek Commission approval prior to commencing negotiations. If a failed project is being replaced by a Company-owned project, however, the Company would be required to do the following: (a) notify the Commission and provide additional evidence and detail regarding the steps taken to attempt to

[258] 120-Day Report, pp. 44-46.
[259] Staff's Comments, p. 66.

remediate the failed project; (b) retain the burden to prove that the Company-owned project was the prudent replacement; and (c) provide robust alternatives analysis as part of the follow-on CPCN proceeding. Regarding the available pool of backup bids, Staff recommends that any project included in the Company's inverse Preferred Portfolio that is not ultimately approved in this Proceeding should be eligible for inclusion in the back-up pool.[260]

228. Similar to Staff, CIEA approves of the backup bid concept and recommends that the Commission approve the backup bid projects as contingency projects. However, CIEA asserts that it will be important for the Commission to clarify the back-up bid process and list clear criteria to avoid controversy in the implementation of Phase II.[261]

229. COSSA/SEIA also raises concerns with perverse incentives that could arise when an IPP project fails but focuses its concern on the Company's ROFO. The ROFO is a provision in the model PPA that allows the Company to step into a failed IPP project and take over development. COSSA/SEIA recommends that the Commission require the Company to first use its identified list of backup bids before deploying the ROFO, as the latter guarantees that the Company's ownership share will grow after a project fails. COSSA/SEIA argues that allowing for ROFO to be used prior to backup bids could incentivize the Company to slow-walk PPA negotiations, placing IPP projects in peril, with the knowledge that the Company can simply offer to buy the developer out if or when the project goes south.[262]

230. In its Response Comments, the Company agrees that some of the intervenor recommendations have merit but argues for the importance of maintaining price integrity and

[260] Staff's Comments, p. 66.
[261] CIEA's Comments, pp. 24-25.
[262] COSSA/SEIA's Comments, pp. 18-20.

allowing for flexibility to move to a backup bid for timely replacement.[263] The Company argues that, to the extent practicable, the Company will try to select "like for like" backup bids both in terms of technology and ownership. More specifically, Public Service argues that it should be able to move forward with an IPP backup bid after a simple notice provided to the Commission and when the backup bid is Company-owned, the Company should only be subject to a "limited-scope" CPCN process similar to any other Company-owned project in an approved resource plan.[264]

231. Public Service argues against adopting an approach set forth by Staff and others in which the Company would be required to undergo more process when it replaces and IPP project with a Company-owned project. The Company acknowledges the "academic" concerns about perverse incentives but argues that its commitment to strive for "like for like" replacements and the Company's conduct in this Proceeding should comfort the Commission.[265] Public Service further argues that a limited scope CPCN is appropriate because Company-owned replacement projects would need to move quickly in order to meet resource needs.

232. Public Service also argues the presumption of prudence under Rule 3617(d) should apply to all backup bids as they move forward, providing regulatory certainty for these projects.

233. Finally, in its Response Comments, Public Service notes two resource modifications in the UPP: (1) replacing a Company-owned solar plus storage project (Bid 0476) with an IPP solar plus storage project (Bid 0303), and (2) replacing a Company-owned wind project (Bid 0045) with a different Company-owned wind project (Bid 1024). The Company also requests that the Commission approve a specific backup for Bid 0044. Bid 0044 is an IPP wind

[263] Public Service's Response Comments, pp. 39-40.
[264] Public Service's Response Comments, p. 42.
[265] As an example of the Company's conduct, Public Service notes that in the UPP the Company proposes to replace a Company-owned bid (Bid 0467) with an IPP bid (Bid 0303). (Public Service's Response Comments, p. 42).

bid that might not be able to move forward at its as-bid price. The Company requests that the Commission approve Bid 0254 as its backup. Bid 0254 is also an IPP wind project.[266]

234. Because the resource modifications in the UPP impact the backup bid portfolio, Public Service provides an updated portfolio of backup bids set forth in Table 3 of its Response Comments.[267]

2. Findings and Conclusions

235. At the outset, the Commission expressly approves the updated list of backup bids set forth in Table 3 of the Company's Response Comments. Recognizing that the backup bids in Table 3 were compiled in anticipation of the UPP and not the Alternative Portfolio, however, we clarify that the Company may use its discretion to adjust the portfolio of backup bids as necessary given the authorizations we have attached to the Alternative Portfolio. For instance, consistent with Staff's recommendation to include projects from the inverse Preferred Portfolio, it would be reasonable to include as a backup bid any bid within the UPP that is not in the Alternative Portfolio.

236. In addition, we agree with the Company's position and confirm that the presumption of prudence set forth in Rule 3617(d) applies to any backup bid that moves forward in accordance with the Commission's approved process for selecting backup bids.

237. Regarding the selection of backup bids, the Commission finds merit in the concerns raised by Staff, CIEA, and COSSA/SEIA that there should be more process in place for when Public Service selects a Company-owned backup bid or when the Company uses its ROFO to buy-out a failing IPP bid. We find persuasive the arguments regarding perverse incentives and worry that without additional process, the selection of a Company-owned backup bid or the

[266] *See* Public Service's Response Comments, p. 6.
[267] Public Service's Response Comments, p. 27.

exercise of the Company's ROFO could give rise to the appearance of bias. While the Commission acknowledges the benefits of allowing the Company discretion to quickly pivot to a backup bid, these benefits must be balanced with guardrails that protect customers, enhance fairness amongst bidders, and increase transparency. Conversely, the Commission disagrees with suggestions from CIEA that the Commission should establish clear criteria for the selection of backup bids or mandate like-for-like replacements. Apart from concerns regarding the selection of a Company-owned bid instead of an IPP project, we believe that Public Service should have the flexibility to use its discretion to select the most appropriate backup bid.

238. Accordingly, we generally adopt Staff's suggested approach in which—among other things—Public Service retains the burden of proving that any Company-owned backup project was the prudent replacement and would need to provide a robust alternatives analysis as part of the follow-on CPCN proceeding.[268] The additional protections set forth in Staff's approach also apply when the Company exercises its ROFO and when the Company replaces a Company-owned project with a Company-owned backup. That said, we emphasize that the additional process set forth in Staff's proposal must move quickly, especially in instances in which the replacement is like for like.

239. Finally, we clarify that the backup bid selection process set forth above does not apply to the two replacement projects the Company proposed as part of the UPP. Specifically, the Company may replace Bid 0476 with Bid 0303 and may replace Bid 0045 with Bid 1024. The Company already explains the need for replacement and the economics of alternative backup bids in its Response Comments. Moreover, the concerns that the Company would have perverse incentives during PPA negotiations do not apply at this point in the process. For the same reasons,

[268] *See* Staff's Comments, p. 66.

we approve Bid 0254 as the backup bid for Bid 0044 if Bid 0044 cannot move forward. Acknowledging that the Company's Response Comments presumed the selection of the UPP, as opposed to the Alternative Portfolio, we clarify that the Company has the flexibility to make the necessary resource modifications consistent with the Company's Response Comments.

K. Section 123 Resources

240. In the 120-Day Report, Public Service states five bids qualified as Section 123 Resources pursuant to the criteria established in the Phase I Decision.[269] In addition to the Hayden biomass project, Bids 0011, 0106, 0269, and 0552 were considered as Section 123 Resources. Other than the Hayden biomass, only Bid 0011 was sometimes selected in the Phase II portfolios.[270] While Public Service included the Hayden biomass project in its Preferred Portfolio, the Company rejected the other Section 123 resources for various reasons, including cost, project risk, and location. Regarding Bid 0106 (a hydrogen fuel cell project) and Bid 0269 (a long-duration storage project), the Company states that there could be long term benefits if these projects are successful. Public Service states that the Company would be interested in moving forward with these projects if the Commission were to approve them *in addition to* the other projects in the Preferred Portfolio.[271]

241. CEO supports the Commission approving Bid 0106 (the hydrogen fuel cell project). CEO argues that pursuing this project as a firm resource would help the state continue its development of hydrogen as a pathway to decarbonization. While CEO acknowledges the project involves certain risks, CEO argues that the potential benefits outweigh these risks, noting that the

[269] Public Service notes that one additional project claimed Section 123 but did not meet the Phase I Decision's criteria.
[270] 120-Day Report, p. 139.
[271] 120-Day Report, pp. 150-51.

State intends to continue pursuing the development of hydrogen. Alternatively, if the Commission does not believe it is the right time to approve the project, CEO recommends that the Commission "direct Public Service to pursue a similar project in either the Just Transition Plan or through its next ERP in 2026."[272]

242. In its Response Comments, Public Service maintains that it does not recommend approval of the project as part of this Phase II ERP. However, the Company states that it appreciates and shares CEO's interest in pursuing the hydrogen fuel cell project and that Public Service is interested in exploring the viability of the project. Public Service goes on to state that it sees opportunities to pursue Bid 0106 or other hydrogen projects as part of proceedings conducted pursuant to HB 23-1281, the upcoming 2024 JTS, or through a separate filing.[273]

243. Pursuant to § 40-2-123(1)(a), C.R.S., the Commission shall:

> give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, insulation from fuel price increases, and environmental protection, including risk mitigation in areas of high wildfire risk as designated by the state forest service.

244. As required, the Commission has fully considered Section 123 Resources. This consideration began in Phase I when the Commission approved a modeling approach for Section 123 Resources and adopted guidelines proposed by Public Service to define these resources, emphasizing that they must be new, innovative, not commercialized, and could not include standalone wind, solar, or lithium-ion storage.[274] This framework enabled the efficient presentation of Section 123 Resources in the 120-Day Report, which in turn allowed the

[272] CEO's Comments, pp. 18-20.
[273] Public Service's Response Comments, pp. 110-11.
[274] Phase I Decision, ¶ 501.

Commission and stakeholders to evaluate the various risks and potential benefits of the Section 123 Resources.

245. We have considered the beneficial attributes of all of the Section 123 Resources, including Bid 0106 which CEO supports. We further note that the Alternative Portfolio includes Bid 0011 which, while proposed as a Section 123 Resource, was included based on economic modeling. As to the question of whether additional Section 123 Resources should be pursued at this time, however, we agree with Public Service's position set forth above in its Response Comments. Given uncertainty ranging from tax credits to the implementation of HB 23-1281, it would be premature to approve additional projects here, including Bid 0106. Should hydrogen projects be included as bids within the 2024 JTS, they can be more appropriately considered there. Accordingly, no further Section 123 Resources are approved here, and we look forward to consideration of innovative technologies in the 2024 JTS.

L. Prospective New Load

246. In its 120-Day Report, Public Service states that large loads, such as the demand and energy requirements of new data centers, are developing at a faster pace than historic trends. The Company thus requests that the Commission approve a "Prospective New Load Preferred Plan" (PNL) portfolio to accommodate potential new load of 300 MW beginning in January 2026. Public Service states that at least some of this 300 MW new load would be better described as "more likely" than "possible." The Company recommends the Commission allow it to use the backup bid pool to serve this load if needed. Public Service specifically puts forth four additional bids that would be included in the PNL portfolio: two storage projects, as solar project, and a 219 MW gas project.[275]

[275] 120-Day Report, pp. 55-57.

247. Several parties, including CEO, Conservation Coalition, Interwest, Staff, and WRA raise concerns about the PNL portfolio, particularly its inclusion of 219 MW of new gas generation. CEO and Staff suggest that the new load is speculative and could fail to materialize, and with Conservation Coalition and WRA, recommend that new load be addressed as part of the load forecast in the 2024 JTS.[276] Staff asserts that two large wholesale loads have announced the intention to leave the Company's system but remain in the Company's load forecast, which cuts against the arguments that additional generation resources will be necessary. Likewise, Staff critiques the Company's demand response sensitivity analysis, arguing that aggressive demand side solutions would mitigate concerns regarding new load.[277] CEO adds that if the Commission does approve the PNL portfolio, it should ensure ratepayer protections if the new load fails to emerge. For example, CEO suggests that if new load does not emerge, shareholders should be responsible for the cost of additional new gas generation instead of ratepayers.[278]

248. In its Response Comments, the Company maintains that that the PNL portfolio has value in this Proceeding and as a general resource planning matter in the current environment. Public Service acknowledges intervenors' comments that new load is speculative but states that it has more information than intervenors and reiterates the challenge associated with new, large loads developing at a faster pace than before. Public Service agrees, however, that should additional resources not be approved for procurement here, it is reasonable to revisit the issue in the 2024 JTS.[279]

[276] Staff's Comments, pp. 53-54; CEO's Comments, pp. 15-16; WRA's Comments, pp. 19-20; Conservation Coalition's Comments, p. 14.
[277] Staff's Comments, pp. 53-54.
[278] CEO's Comments, p. 16.
[279] Public Service's Response Comments, p. 106.

249. We take the risk that new load is increasing seriously,[280] but we decline to approve the PNL portfolio. We agree with Staff's assertion that based on what is currently publicly known, these load additions are speculative and could be offset by future load departures and more effective efforts around demand response. Moreover, given that the new load is speculative but would directly result in adding a new gas resource, it deserves both the full vetting of a Phase I process, through which such questions of appropriate load forecasts and sensitivities are traditionally considered, and consideration as to the impact of new large loads that might seek economic development rates on state emissions targets.

M. Clean Energy Plan Rider (CEPR)

250. Section 40-2-125.5(5), C.R.S. authorizes Public Service to initiate a CEPR, capped at a maximum rate of 1.5 percent of customers' total electric bill, to collect new revenues to fund the approved, additional clean energy plan activities that are undertaken to meet the clean energy target applicable to the Company. However, the statute also prescribes limitations on what the CEPR can fund.

251. In Phase I, the Commission rejected the complex, counterfactual modeling proposal put forward by Public Service in support of the approval and prospective implementation of its CEPR. The Commission further declined to move forward with Public Service's presumption that the Company could apply RESA funding to offset CEP costs, even as the Commission approved certain related provisions of the Phase I Settlement that relate to reporting and treatment of over- and under-collections. Instead, the Commission directed Public Service to file significantly more detail on anticipated cost recovery mechanisms in the 120-Day Report and to file an

[280] To address this risk, we encourage Public Service to work to ensure that it has additional firm dispatchable resources as close to construction ready as reasonably possible.

application in a separate future proceeding presenting its methodology for defining and assigning costs related to additional clean energy activities as between the CEPR and the RESA, no later than one year in advance of beginning to recover costs attributable to the CEPR.

1. Public Service's New CEPR Proposals and Party Comments

252. In its 120-Day Report, Public Service completely revises its cost recovery methodology as compared to the proposals the Company presented in Phase I of this Proceeding. For instance, the Company compared its Preferred Portfolio to the reference case and identified the following incremental actions and investments: acquisition of clean energy resources, the Brush Coal Plant gas conversion, reduction of Pueblo Unit 3 operations, gas storage, transmission, and community assistance and workforce transition plans. Out of these, Public Service states that clean energy resources, Brush Coal Plant conversion costs from 2025-2030,[281] and community assistance and workforce transition plans should be considered clean energy plan activities that are eligible for CEPR recovery (noting that community assistance and workforce transition costs are statutorily also eligible to be recovered through other riders). Public Service explains that, pursuant to § 40-2-125.5(5)(b)(III), the Company will exclude transmission, fuel costs for Pueblo unit 3 operations, and gas storage, and proposes they be collected from other cost recovery mechanisms, such as the ECA, the Transmission Cost Adjustment, and base rates.[282]

253. To attribute the costs of clean energy plan activities to the CEPR, Public Services proposes to sort resources into energy or capacity and then to stack them from lowest to highest based on accredited capacity and levelized cost of energy or capacity calculated using Encompass, the model used for bid evaluation and selection.[283] This approach results in three solar and storage

[281] The Brush Coal Plant conversion costs are also being considered within Proceeding No. 22A-0563E.
[282] 120-Day Report, pp. 168-69.
[283] 120-Day Report, p. 169.

resources being identified as attributable to the CEP in the "energy resource stack" and no resources being identified as attributable to the CEP in the "capacity resource stack." Public Service suggests refining this methodology and extending it to CEPR/RESA interactions through the post-Phase II application. Public Service also adds that the exact costs for community assistance and workforce transition will be evaluated in future JTP filings.[284]

254. Public Service requests that the Commission authorize it to file an advice letter to initiate the CEPR for collections purposes beginning either January 1, 2024, or January 1, 2025, depending on when the Phase II Decision is issued. Public Service forecasts that by starting collections at 1.4 percent in 2024, it would be over-collected by $6.3 million in 2030, and it would be under-collected by $19.3 million in 2030 if it began collections at 1.5 percent in 2025.[285]

255. UCA raises concerns about the Company's approach, including that the presentation of levelized energy costs for resource stacking does not match costs presented in appendices, and therefore the bids may be incorrectly sorted as to cost recovery mechanism. UCA further argues that the costs associated with the early retirement of Hayden 1, Hayden 2, Craig 2, and the entire costs of the Brush Coal Plant conversion should be considered CEP costs, and therefore the under-collections for the CEPR will be higher than Public Service anticipates.[286]

256. Public Service argues that UCA has not correctly applied updated modeling values and explains that only the conversion of the Brush Coal Plant from coal to gas would be considered an additional clean energy plan activity. With regard to the RESA, Public Service states that the methodology it used to distinguish between the ERP and the CEP will also be used to distinguish between clean energy resources and eligible energy resources. The Company reiterates that it

[284] 120-Day Report, pp. 170-72.
[285] 120-Day Report, pp. 172-73.
[286] UCA's Comments, pp. 27-28.

intends to file the application presenting its methodology for defining and assigning costs between the RESA and CEPR promptly after the final Phase II decision, consistent with the Phase I decision. Accordingly, Public Service reiterates its request that the Commission approve the establishment of the CEPR at the full 1.5 percent in its Phase II decision, with collections to begin as soon as possible upon filing of an advice letter.[287]

2. Findings and Conclusions

257. We conclude that further process is still required to determine whether the CEPR should be initiated at the full 1.5 percent as proposed by Public Service in its 120-Day Report. Nevertheless, we generally agree with, and approve, its categorization of actions and investments which should be considered additional clean energy plan activities, including those that may be recoverable through the CEPR,[288] as the Company's new proposals are clearer and will avoid the inappropriate levels of complexity that were present in the counterfactual Phase I proposal.[289] That said, given its late introduction, the balance of the Company's latest CEPR proposals has not been fully vetted by stakeholders and questions remain as to variations between data tables and appendices. Moreover, the application of this methodology for RESA/CEPR cost recovery is less clear than its applicability for ERP/CEP questions. Finally, the Commission has selected the Alternative Portfolio instead of the UPP, necessitating greater clarity on cost recovery (*e.g.*, whether the resource stack changes and results in different allocations between cost recovery mechanisms).

[287] Public Service's Response Comments, pp. 98-100.

[288] To clarify, consistent with the discussion above, transmission investments as presented in the 120-Day Report are not considered additional clean energy plan activities.

[289] We note that while the Commission deferred the specifics of cost recovery for early retirement for Craig 2, Hayden 1, and Hayden 2, it approved the provisions of the Phase I Settlement that affirmed that they should be excluded from CEPR recovery (*i.e.*, they would be included within the reference case for modeling purposes), (Phase I Decision, ¶ 63; Phase I Settlement, ¶¶ 27-28). *See also* Proceeding No. 22A-0515E.

258. Given the timing of this Phase II Decision, pursuant to § 40-2-125.5(b)(II), C.R.S, the earliest the CEPR would be able to be placed into effect is January 1, 2025. Accordingly, we direct the Company, as part of its application regarding attribution of costs between the CEPR and RESA as still required by the Phase I Decision, to address the recovery of specific activities within the categories set forth above, based on the approved resource portfolio. The application should also address the appropriate level for the CEPR to be initiated on January 1, 2025.

N. Best Value Employment Metrics

259. The Phase I Settlement established a multistep process in the Phase II bid evaluation to ensure consideration of BVEM in accordance with § 40-2-129(1)(a), C.R.S. First, the RFP directed bidders to include quantitative information with bid packages that addressed the BVEM statutory requirements, including access to apprenticeships and industry-standard wages and benefits. Second, a bid incorporating a Project Labor Agreement (PLA) was deemed to meet threshold BVEM standards. Third, the Company agreed to screen bids based on BVEM and disqualify those that did not provide sufficient BVEM. Fourth, the Company would retain a labor economist to score the bids for advancement to computer modeling. The Phase I Settlement goes on to specify that the Company will provide a cumulative BVEM score for each portfolio in the 120-Day Report.[290] Finally, one of the required Phase II portfolios was a "high PLA portfolio."

260. In the 120-Day Report, Public Service confirms that it implemented this multi-step BVEM process during Phase II. The Leeds School of Business at the University of Colorado-Boulder was hired as a labor economist and provided scoring of 166 bids. The Company states that it disqualified bids with insufficient BVEM information. In addition, the

[290] Phase I Settlement, ¶ 69.

Company notes that Appendix K to the 120-Day Report contains the BVEM documentation that the bidders provided.[291]

261. The Labor Interests describe the challenging history of Colorado's efforts to account for the employment impacts of resource planning through the Phase II solicitation and modeling process. The Labor Interests describe the quantitative scoring provided by the labor economist as a positive evolution in the consideration of BVEM but remain concerned that BVEM was less emphasized after bids were advanced to modeling. Ultimately, however, the Labor Interests support the Preferred Portfolio including the Hayden biomass unit as having a strong BVEM score that matches or exceeds other modelled portfolios and offers an imperfect, but positive, middle ground. The Labor Interests note the positive relationship between utility ownership and BVEM due to Public Service's involvement in collective bargaining.[292] They further add that SB 23-292 is a recent and strong statement in support of robust and protective labor policies which will have a significant impact on all phases of energy generation in the future.[293]

262. Staff argues that the RFP informed the bidders of the categories and subcategories of information that would be used to develop the BVEM score, however, it did not specify the weighting of these categories and subcategories to the bidders. Staff is concerned that the approach incentivizes detail over quality. Staff suggests that the BVEM scoring methodology could use improved documentation as verifying the methodology is challenging due to lack of sufficient information. That said, Staff notes that it checked for consistency of BVEM scoring across

[291] 120-Day Report, pp. 159-60.
[292] Labor Interests' Comments, pp. 7-8.
[293] Labor Interests' Comments, pp. 8.

different bids and found it to be consistent and objective.[294] WRA likewise supports utilization of a BVEM scoring methodology in future ERPs.[295]

263. In its Response Comments, Public Service agrees with the Labor Interests that the BVEM scoring methodology in this ERP is an improvement and should be continued, with iterations. Public Service specifically supports using a similar BVEM scoring methodology in future ERPs, including the 2024 JTS.[296]

264. As noted earlier, the Commission has considered the employment of Colorado labor and its positive impacts on the long-term economic viability of Colorado communities throughout this ERP proceeding pursuant to § 40-2-129, C.R.S. These considerations began in Phase I of this Proceeding when the Commission approved the multistep process in the Phase II bid evaluation regarding BVEM and continued in Phase II in our review of the 120-Day Report, the relevant party comments, and the cumulative BVEM score for all portfolios. In addition to BVEM, the Commission must consider and balance many factors in its decision regarding the optimal resource portfolio, including emissions reductions, costs, and reliability. The consideration of these combined factors culminates in a Phase II decision.

265. The Alternative Portfolio has a slightly lower BVEM score (48 percent) than the UPP's BVEM score (52.7 percent). Nevertheless, we find that the positive attributes of the Alternative Portfolio, including cost, emissions reductions, reliability, and the ability to better address future technology developments and transmission concerns as detailed above, outweigh the lower BVEM score.

[294] Staff's Comments, p. 68.
[295] WRA's Comments, pp. 25-29.
[296] Public Service's Response Comments, pp. 106-07.

266. As Labor Interests set forth, the process of evolving a qualitative concept like BVEM into a meaningful component of bid evaluation has been a long and thoughtful process, with a significant amount of evolution demonstrated through the Phase I Settlement and Phase II. In such a sweeping and significant process as an ERP, even though moving incrementally can be frustrating, nuanced iterations are often the best course of action.

267. Moreover, the Alternative Portfolio includes slightly fewer resources and therefore will provide time for the application of BVEM to continue to evolve. This also means that resources that are deferred now could be brought into the future ERPs through an even more robust process, which is necessary to comply with additional statutory requirements in § 40-2-129, C.R.S.[297]

268. We also agree with Labor Interests that the thoughtful work performed by the labor economist in this Proceeding represents an enhancement of how BVEM can be incorporated into decision-making. However, Staff also raises valid points in that the methodology could be more clearly articulated for bidders. In this vein, we would be interested in seeing proposed changes to the model PPAs in the 2024 JTS aimed at clarifying standards for BVEM to ensure that IPPs and the Company are competing on a level playing field regarding BVEM. We encourage the collaboration of Labor Interests in this effort, such that work on the model PPAs will account for the role that the IRA can play in producing projects with high BVEM scores by incorporating factors such as the IRA's prevailing wage requirements. We also note that high BVEM scores generally track high utility ownership percentages and express our desire that IPPs that are interested in building projects in Colorado should improve their BVEM to ensure they stay competitive with Company-owned bids in this regard.

[297] These new requirements in § 40-2-129, C.R.S., are effective January 1, 2024.

O. In Service Date Extensions

269. In connection with the delays in this Proceeding associated with Public Service's filing of the 120-Day Report, CIEA argues that the Commission should allow IPPs to have a corresponding extension of the ISDs of their projects. CIEA specifically proposes that all projects in the selected portfolio as well as backup bids with ISDs in 2026 and 2027 (spilling into 2028 by up to 75 days if necessary) should have a one-time election to extend the ISDs up to 75 days. CIEA argues that this will address the acute issues in the market and Public Service's delays in the Phase II process in a straightforward and transparent manner.[298] In addition, CIEA requests that backup bids should be granted an ISD extension equal to the number of days after the Phase II Decision when the backup bid gets approved to move to the selected portfolio.[299]

270. In its Response Comments, the Company supports CIEA's recommendations and agrees that all project developers should have the opportunity to extend the ISD of their approved projects and backup bids commensurate with the extended Phase II timeline. The Company further recommends the Commission acknowledge that delays in generation resource ISDs due to transmission-related delays, such as delays associated with interconnection, backfeed, and substation construction, shall be considered reasonable.[300]

271. Likewise, Public Service asserts that backup bids should be allowed an extension of their commercial operation date (COD) by the number of days after the Phase II Decision that the backup bid is approved to move to the selected portfolio. The Company supports this COD extension because selected backup bids will see a delay in their selection given their backup bid

[298] CIEA's Comments, pp. 41-42
[299] CIEA's Comments, pp. 41-42.
[300] Public Service's Response Comments, pp. 103-04.

status, and the COD extension increases the likelihood that the backup projects will come to fruition.[301]

272. In accordance with CIEA's recommendations, we authorize Public Service to extend ISDs upon application by IPPs by up to 75 days as well as any delays in transmission assets to which individual projects interconnect. No support should be required of the IPP for ISD delays of 75 days or fewer. Before granting an ISD extension greater than 75 days, the Company should be directed to obtain a thorough and credible explanation from the IPP detailing how delays related to completion of Public Service transmission projects prevented it from achieving its proposed ISD. We likewise adopt the ISD extension for backup bids that Public Service sets forth in its Response Comments.

P. Repricing

273. CIEA also requests that the Commission clarify that Public Service can allow IPPs to reprice their projects if delays in transmission project completion cause cost increases through no fault of the IPP. CIEA asserts that IPPs "cannot be expected to maintain as-bid pricing through material delays in transmission upgrade and interconnection processes."[302] CIEA similarly argues that backup bids are likely to be stale by the time Public Service calls upon such bids to move forward. Accordingly, CIEA argues that the Commission should allow an opportunity for limited repricing of backup bids to keep up with inflation.[303]

274. Public Service argues against the suggestion that backup bids should be provided a repricing opportunity, arguing that doing so could impugn the integrity of the process. However, the Company does support allowing price increases in the limited circumstance where a

[301] Public Service's Response Comments, pp. 40-41.
[302] CIEA's Comments, p. 22.
[303] CIEA's Comments, p. 25.

transmission cost estimate is different than the estimate provided as part of the RFP. Public Service states that this should be the only basis for repricing and should be equally applicable to any bid with which the Company moves forward.[304]

275. The Commission agrees with Public Service's position and denies CIEA's request to allow backup bids to reprice. The one exception is that repricing is allowed for backup bids in the case where the transmission costs provided in the RFP have changed, consistent with Public Service's proposal in its Response Comments.

Q. 2024 Just Transition Solicitation

276. Given the various issues that have arisen in Phase II of this Proceeding, several intervenors argue that the Commission should issue various directives to Public Service to improve the ERP process. As discussed below, these proposed improvements cover topics including modeling, the ability of IPPs to negotiate the terms of Model PPAs during Phase II, and the appropriate amount of Company ownership.

1. Modeling Improvements

277. Staff, CIEA, Interwest, Conservation Coalition, and WRA all put forth various proposals aimed at improving the modeling process of bids in the 2024 JTS. Relatedly, CEO suggests process improvements for the 2026 ERP. For example, CIEA's proposals include asking the Commission to reject the use of the things like the best-in-class modeling and the reliability rubric for use in the 2024 JTS.[305] CIEA also argues that the annuity method of modeling portfolios should be used going forward and that Public Service should be required to analyze the failure of

[304] Public Service's Response Comments, p. 41.
[305] CIEA's Comments, pp. 6-7, 29-31.

the model and possible solutions, including a process for returning to the Commission in the event of model failures.[306]

278. Interwest requests that the Commission require a full analysis of both the computer system used in this ERP as well as an estimate of what computer system would have been able to run the modeling software in the timeframe required under the ERP rules.[307] For future ERPs, Interwest argues that the curtailment projections must be more flexible and consider the likelihood that curtailments will be reduced over the long term.[308]

279. Conservation Coalition proposes numerous directives for the Commission to issue regarding the 2024 JTS. As an example of some of these proposals, Conservation Coalition argues that the Company should be required to provide the modeling input and output files to all parties and provide written explanation for all manual adjustments made to the modeling. Conservation Coalition also recommends that the Commission require the use of round-trip modeling, building all portfolios to the same minimum level of reliability, and running a scenario in which, the model replaces all 2-hour storage with 4-hour storage. Similarly, Conservation Coalition argues that Public Service should be required to conduct capacity accreditation studies and planning reserve studies in the same software tool and database to ensure consistency.[309]

280. WRA's proposals include things such as how generic prices should be used, requirements for the IE, and—more broadly—a different approach to ERP solicitations that uses sequential, rolling solicitations. WRA also proposes that Public Service develop and propose a

[306] CIEA's Comments, pp. 30-31.
[307] Interwest's Comments, p. 11.
[308] Interwest's Comments, p. 12.
[309] Conservation Coalition's Comments, pp. 18-20.

transparent scoring system for non-price factors, such as environmental compliance and community support.[310]

281. Arguing for higher-level changes to the ERP process, CEO raises concerns that the ERP process fails to develop a set of portfolios that are significantly different in terms of the resources considered or even the relative cost. Citing its proposals in Proceeding No. 19R-0096E for requiring electric utilities to submit various types of plans with their ERPs, CEO recommends that the Commission direct the Company to include scenario-type analysis as part of the 2026 ERP. CEO also encourages the Commission to re-open its ERP rules and adopt new rules that are more relevant to today's utility environment and that will help Colorado achieve its climate goals. [311]

282. Staff proposes that the Company explain in the 2024 JTS how it will update the effective load carrying capability (ELCC) and planning reserve margin (PRM) studies with the goal of accurately modeling portfolio level ELCC interactions to create reliable portfolios in EnCompass. Staff also recommends that Public Service work with Staff prior to the 2024 JTS to develop more robust modeling processes regarding things like best-in-class modeling, the reliability rubric, meaningful demand side resources options, and inconsistent or unexplained modeling results.[312]

283. In its Response Comments, the Company does not oppose Staff's recommendation to include an explanation in the Pueblo JTP filing as to how it plans to improve the accuracy of modeling portfolio level ELCC interactions.[313] However, Public Service appears to disagree with

[310] WRA's Comments, pp. 25-29.
[311] CEO's Comments, p. 30.
[312] Staff's Comments, p. 74.
[313] Public Service's Response Comments, p. 104.

Staff's recommendation that the Company be required to work with Staff in the interim to develop more robust modeling processes.[314]

284. Regarding Conservation Coalition's recommendation that the Company conduct capacity accreditation studies and planning reserve studies in the same software tool, Public Service states that, as part of the Phase I Settlement, the Company has already committed to utilize the same modeling software and inputs for ELCC and PRM studies in future resource planning cycles and will also survey best practices in other jurisdictions when developing its methodology for these studies. The Company thus argues that the Phase II Decision does not need to reiterate this requirement.[315]

285. As for the arguments about increased information sharing, process improvements, and transparency, the Company asserts that no directives addressing these issues should be issued in this Proceeding. While Public Service acknowledges that there is always room for improvement in the resource planning and intervenor participation process, the Company argues that such issues are more appropriately resolved a part of a robust Phase I process in the 2024 JTS and the 2026 ERP.[316]

286. The Commission hereby adopts Staff's recommendations and will require Public Service to explain how the Company plans on accurately modelling portfolio level ELCC interactions in connection with its updated ELCC and PRM studies. We further direct the Company to confer with Staff and other interested parties prior to the 2024 JTS to develop more robust modeling processes regarding things like best-in-class modeling, the reliability rubric, meaningful demand side resources options, and inconsistent or unexplained modeling results.

[314] Public Service's Response Comments, p. 112.
[315] Public Service's Response Comments, pp. 104-05.
[316] Public Service's Response Comments, pp. 111-12.

287. In contrast, we decline to adopt in this Phase II Decision the numerous other modeling and process proposals, including those proposed by party commenters that are expressly discussed above. Some of these proposals closely resemble topics that were adjudicated in Phase I (*e.g.*, making the modeling files available for other parties).[317] More generally, the Commission finds that it would be premature on this Phase II record to specify how the next ERP process will resolve these modelling and process issues. Nevertheless, as referenced above, we take seriously the numerous concerns that parties raised regarding how Public Service conducted the Phase II modeling, including the manual adjustments the Company made in Phase II and how difficult it was for the parties to analyze the impact of these adjustments. Likewise, we share many of the parties' concerns regarding the model's shortcomings as to issues such as curtailments and the interaction between new generation and transmission. While resolution of these issues for purposes of future ERP proceedings will benefit from a more robust record than is available to us during this Phase II, many of these concerns contribute to our decision to modify the CEP to include the Alternative Portfolio.

2. Non-Negotiable PPA Terms

288. Interwest asserts that the negotiating process on the model PPAs was not explained in advance and put some bidders at a significant and unexpected disadvantage. Interwest states that Public Service found several redlines to model PPAs unacceptable during the due diligence process, prior to actual PPA negotiations, but necessary to advance in the bid selection process. Interwest recommends that the Commission consider language in the Phase II decision specifying that only after a bid is selected should the PPA negotiations start, and Public Service should be

[317] Phase I Decision, ¶ 513.

prohibited from using the threat of bid elimination to force bidders to accept terms that this Commission has specifically intended to be negotiable.[318]

289. COSSA/SEIA similarly recommends that the Commission mandate that the Company identify which model PPA terms it considers non-negotiable, and that this be litigated in Phase I of future ERP proceedings so that all parties would enter Phase II on the same page about which terms are open to negotiation.[319]

290. CIEA claims that many IPPs felt bullied to identify model PPA-changes they would accept or forego the opportunity to raise such issues later in contract negotiation and were pressured to adopt Public Service's position just to remain in the evaluation process. CIEA recommends that the Commission direct a new approach that limits Public Service's ability to negotiate PPA terms with bidders during the bid evaluation process.[320]

291. In Public Service's Response Comments, the Company argues that the Commission should reject recommendations that would restrict the Company's ability to negotiate PPA terms with bidders during the bid evaluation process. The Company argues that to the extent bidders do not submit compliant bids, the Company must retain the ability to work with bidders to bring bids into compliance and ensure a viable and comparable bid pool. The Company does, however, support recommendations from CIEA and COSSA/SEIA that non-negotiable model PPA provisions be clearly set forth in its Phase I 2024 JTS filing and be formalized in the Commission's Phase I decision. Public Service states that doing so will provide additional clarity to bidders and

[318] Interwest's Comments, pp. 9-10.
[319] COSSA/SEIA's Comments, pp. 15-18.
[320] CIEA's Comments, pp. 32-35 ().

would help mitigate the need for extensive PPA contract discussions during the bid evaluation process.[321]

292. The Commission agrees with the IPP intervenors and the Company that there should be more clarity for bidders regarding what terms of the model PPA contracts are negotiable. We accordingly adopt Public Service's position and require the Company to clearly set forth the non-negotiable PPA terms in its Phase I 2024 JTS filing with the expectation that such terms will be formalized in the Commission's Phase I decision approving model PPAs.

293. As noted by Interwest and Public Service, "Colorado does not have a 'conforming bid' policy whereby bidders have to bid to the model agreements 'as-is.'"[322] However, having the Company and IE attempt to determine on an *ad hoc* basis during the bid evaluation process which terms of the PPAs are negotiable is a challenging situation. We acknowledge that it may be time for Colorado to move towards a conforming bid policy, especially considering that the Commission already addresses many core issues of the model PPAs in Phase I and the fact that in Phase II the Company and IE are called upon to equitably evaluate numerous bids. To be clear, the Commission is not in this Decision adopting any type of conforming bid policy, but we invite party feedback regarding adopting this type of approach in the future.

3. Company Ownership

294. Interwest takes issue with the high percentage of Company ownership in the portfolios presented in the 120-Day Report, arguing that it is outside of what was expected by virtually all parties. Interwest suggests that this calls into question the validity of the agreements in the Phase I Settlement regarding the amount of replacement capacity from the 2024 JTS that

[321] Public Service's Response Comments, p. 105.
[322] *See* 120-Day Report, p. 86; Interwest's Comments, p. 9.

Public Service would own. Interwest requests that the Commission consider whether Public Service achieved the letter and spirit of the law, whether the Phase I Settlement provisions regarding the ownership of Unit 3's replacement capacity are still valid, and whether action is necessary now to ensure compliance in future ERPs.[323]

295. CIEA similarly recommends that the Commission use the 2024 JTS to course correct and rebalance the resource ownership of IPPs and the Company in the total capacity mix of the system.[324]

296. Public Service urges the Commission to reject suggestions that the ownership percentage allowed in the 2024 JTS be adjusted to account for the high ownership the Company proposes in this Proceeding. Public Service argues that this recommendation could lock the Commission into higher-cost and uneconomic outcomes.[325]

297. The 2024 JTS is an interim ERP that will largely be governed by the Commission's ERP rules. We find that it would be inappropriate in this Phase II to attempt to set bounds around the Company ownership levels of the approved portfolio coming from the 2024 JTS. Moreover, we note that the selection of the Alternative Portfolio significantly reduces the amount of Company-owned capacity resources approved as part of this Proceeding as compared to the UPP.

4. Just Transition Bids

298. UCA expresses disappointment that there were no bids for wind, solar, storage or solar plus storage at Craig or Hayden. UCA claims that such bids would have contributed to the just transition plan. UCA argues that these type of JTP bids should be encouraged at Craig and

[323] Interwest's Comments, p. 9.
[324] CIEA's Comments, p. 18.
[325] Public Service's Response Comments, pp. 33-34.

Hayden and other west slope locations as well as in the Pueblo area. UCA goes on to suggest that such bids could even be required from Public Service.[326]

299. Although we refrain from creating any sort of requirement for certain bids, we agree with UCA's sentiments about the benefits of bids at Craig, Hayden, and Pueblo and encourage such bids in the upcoming 2024 JTS. We further encourage bids within the Denver Metro area to the extent such bids can mitigate the need for additional transmission investments.

300. The 2024 JTS offers the state an important opportunity to continue acquiring renewable resources to achieve even greater emissions reductions while addressing some of the issues that arose in this Proceeding. Consistent with the Phase I Settlement Agreement, however, we reiterate that the 2024 JTS is the proceeding that will acquire a suitable replacement for the capacity that will be lost when Unit 3 retires and that all parties should work to ensure that the Pueblo community and benefits to the community are the focus of this replacement.[327] In this vein, we note that nothing in this Phase II Decision impacts the Company's commitment in the Phase I Settlement to "make payments to Pueblo County annually from 2031 through 2040 … in the amount of the projected lost property tax revenues for those years, unless offset by property tax revenues from generation or transmission infrastructure sited at Comanche Station or within Pueblo County."[328]

[326] UCA's Comments, p. 20.
[327] *See* Phase I Decision, p. 43; Phase I Settlement, ¶ 43.
[328] Phase I Settlement, ¶ 42.

5. Discount Rates

301. Conservation Coalition suggests that the Commission direct the Company to confer with stakeholders to reach a consensus approach to discounting the social cost of emissions for the June 2024 JTS.[329]

302. While consideration of lower discount rates does not warrant the selection of a different resource portfolio in this Proceeding (as set forth above), we find merit in the Conservation Coalition's request that Public Service attempt to reach consensus with stakeholders on the related issue of discounting the social cost of emissions. Accordingly, we grant Conservation Coalition's request and direct the Company to confer with stakeholders to reach a consensus approach to discounting the social cost of emissions for the 2024 JTS. This conferral should include the impacts of SB 23-291 regarding the appropriate discount rate to use for fuel costs.

6. Comprehensive Rate Analysis

303. In the 120-Day Report, Public Service states that "the average bill impact for the Preferred Plan is expected to grow less than the historical rate of inflation."[330] Staff, UCA, and CEC argue, however, that the costs presented in the 120-Day Report are likely to be artificially low.[331] Staff in particular states that there is additional anticipated investment that is not included in the Company's rate impact analysis. Staff asserts that the Company's statement regarding the cumulative average growth rates was carefully worded to include only the incremental rate impact of the CEP, not the rate impact of the entirety of the Company's planned investments including

[329] Conservation Coalition's Comments, pp. 21-22.
[330] 120-Day Report, p. 34.
[331] Staff's Comments, p. 19; UCA's Comments, pp. 5-7; CEC's Comments, pp. 15-16.

distribution system investment, other transmission system investment, and additional electric generation not included in this Proceeding.[332]

304. Given the importance of affordability, the Commission and interested stakeholders should have access to a consistent view of Public Service's capital expansion plan for the Colorado electrical system and what this plan means for ratepayers. Accordingly, the Commission directs Public Service to provide in the 2024 JTS a comprehensive long-term rate analysis that fully includes all of the projected investments the Company is communicating to the financial community, including for new distribution investment, wildfire mitigation, transmission upgrade, transportation electrification, distributed solar, and other electricity business investments.[333] This comprehensive rate analysis should also include an analysis that better quantifies the actual levels of resource curtailment above the modelled levels and, in format, should be similar to the rate forecast models the Company has recently presented in rate cases.

305. We emphasize that this comprehensive rate analysis shall not be limited to projects that have received official regulatory approval or projects that have final cost estimates. Rather, this comprehensive rate analysis shall include all projected investments in the Colorado electric system that Public Service is communicating to the financial community and any that are reasonably expected.

R. Miscellaneous Issues for Future Proceedings

1. Equity Directives

306. In its Comments on the 120-Day Report, Staff notes the importance of evaluating ERP proceedings through an equity lens. Staff further notes that as part of the solicitation that the

[332] Staff's Comments, p. 19.

[333] Consistent with prior filing expectations, documents are expected to be as robust as possible and in executable format.

Company performed in this Proceeding, all bidders were required to provide information on the assessment of, and plan for continuing to monitor local community, disproportionately impacted (DI) community, and state reaction to the bidder's proposed project, and a plan to work with the local community and DI communities on project issues. In addition, as part of the 120-Day Report, the Company provided maps that identify which projects are located in DI communities.[334]

307. After assessing the information that was received in this Proceeding, Staff makes a series of recommendations that the Commission could take in future proceedings to continue to improve the Commission's consideration of equity issues. For example, Staff argues that in the future, the 120-Day Report should include a more detailed analysis of community/state reaction, which goes beyond identifying the DI communities. Staff also suggests that the Commission consider developing rules that (1) identify key metrics that should be reported by bids in DI communities to help understand impacts and benefits of bids on DI communities, and (2) define a process for tracking stakeholder engagement in bids approved in the resource plan in DI communities. Finally, Staff recommends that the Commission consider specifying how it will consider equity metrics in decision making and document the consideration of energy equity issues in written decisions prior to approvals for Resource Plans, Plan amendments, and CPCNs.[335]

308. In a similar vein, CEO notes with approval how the Company mapped the bids in this Proceeding relative to DI Communities. CEO encourages a similar presentation of mapping in the Company's next ERP and notes the expectation that the Commission will continue to consider how it will use such mapping in its decision making going forward.[336]

[334] Staff's Comments, pp. 69-70.
[335] Staff's Comments, pp. 71-72.
[336] CEO's Comments, pp. 24-25.

309. In its Response Comments, the Company expresses appreciation for Staff's recommendations as the consideration of equity issues in resource planning continues to evolve. The Company notes that it has expanded the scope and reach of its community engagement efforts and expects to continue this expansion. Public Service further expects that the presentation and evaluation of equity issues will continue to improve, similar to how the BVEM bid information and evaluation process has improved. Public Service states that it welcomes and encourages continued discussion in the next ERP Phase I process and in future Just Transition Plan proceedings to ensure meaningful consideration of equity issues but that the Company does not believe specific requirements need be prescribed in rules.[337]

310. We acknowledge and appreciate the considerations from Staff and CEO regarding how to continue improving the Commission's consideration of equity issues in future ERP proceedings and rulemakings. At this juncture, however, we will leave it to the relevant stakeholders to work out the appropriate specifics on when and how best to further advance the consideration of equity issues in resource planning. We note that in Proceeding No. 22M-0171ALL the Commission has an ongoing and far-reaching pre-rulemaking underway aimed at improving equity outcomes in the State through reforms to practices, outreach, and rules. The Commission encourages stakeholders to provide comments within that pre-rulemaking proceeding where we are diligently collecting concepts on what rules should be considered and addressed in order to promote equity.

2. CPCN Prioritization

311. CIEA and Conservation Coalition both encourage the Commission to proactively manage the applications for CPCNs that the Company will eventually file for each utility-owned

[337] Public Service's Response Comments, pp. 107-08.

generation asset included in the approved resource portfolio. For instance, noting the large amount of expected CPCN filings, CIEA recommends that there be a priority established for 2024 CPCNs based on the value to ratepayers of the various projects. Denver metro transmission projects with 2030 ISDs could be delayed to later but generation projects that are critical to system or local reliability should be prioritized.[338]

312. Similarly, the Conservation Coalition suggests that the Commission consider how it can reduce the litigation burden to parties (and the burden on the Commission) of the CPCNs arising from this Proceeding. The Conservation Coalition specifically recommends one of two solutions for consolidating the various CPCNs. The first proposal is to require the Company to confer with all parties and file a reporting containing the proposals for how best to consolidate and minimize the number of CPCN applications. The Commission would then issue an order in this Proceeding addressing consolidation. The second proposal is to simply order the Company to consolidate its CPCN applications based on some criterion or criteria (*e.g.*, technology type or ISD).[339]

313. In its Response Comments, Public Service argues that it has the responsibility to timely file CPCNs and that the Company will need some flexibility to do so. However, the Company proposes providing updates to interested parties and the Commission on the status of CPCN filings in its Annual ERP Reports that it files every year on March 31 as well as in its annual Rule 3205 and Rule 3206 reports. Public Service argues that these existing reporting venues provide the appropriate opportunity for the Company to update stakeholders on CPCN filing

[338] CIEA's Comments, pp. 8, 35-36.
[339] Conservation Coalition's Comments, pp. 22-23.

readiness as well as the anticipated filing dates, sequencing, and grouping of generation and transmission CPCNs moving forward post-Phase II.[340]

314. We adopt Public Service's position set forth in its Response Comments and direct the Company to provide additional updates to interested stakeholders regarding the Company's CPCN prioritization via the existing reporting venues. At this juncture, the Commission will not attempt to dictate the form or timing of Public Service's CPCN and other applications.

3. Voluntary Additional Emissions Reduction Program

315. Boulder recommends the Commission direct Public Service and interested communities and customers to explore acquiring additional resources to support development of a voluntary customer product that generates additional emissions reductions. Boulder asserts that "communities comprising at least 35 percent of Public Service retail sales seek '100% renewable energy' or zero emissions electricity by 2030."[341] Given the importance of decarbonizing the electricity sector as soon as possible to support decarbonization in other sectors like buildings and transportation, Boulder argues that "the time is now to develop next-generation voluntary customer products that quantify incremental emissions reductions."[342]

316. Boulder acknowledges that the Phase I Settlement contains a commitment for Boulder and Public Service to work together to develop such a voluntary program. Boulder indicates that, based on preliminary modeling, it appears that acquiring additional renewable resources could generate incremental emissions reduction but at the significant risk of curtailments. In addition, according to Boulder, the preliminary modeling showed that incremental

[340] Public Service's Response Comments, pp. 100-02.
[341] Boulder's Comments, p. 17.
[342] Boulder's Comments, p. 17.

costs of such additional resources "suggests that new voluntary emissions reduction products must be available to all Public Service customers and not limited to one community or customer."[343]

317. Boulder asserts that the bids received in Public Service's solicitation provide options for the development of a new voluntary emissions reduction product that would enable communities and customers to progress towards their 100 percent renewable energy goals. Boulder suggests that bids included in the Preferred Portfolio could be expanded to add generation or storage, and this expansion could be funded by communities and customers participating in the voluntary emissions reduction program. Boulder also asserts that there are bids that were not included in the Preferred Portfolio, including Section 123 Resources, the acquisition of which could be supported by customers interested a voluntary emissions reduction program.

318. The Commission understands that certain communities and organizations would prefer to exceed the environmental attributes of Public Service's general resource mix via a more robust, voluntary offering and believe such a program is feasible. We are interested in better understanding what steps the Commission could put in place to provide such a voluntary program for customers and communities and how the tracking would work to ensure that the program would not dilute the environmental attributes of the general resource mix or unfairly allocate costs.

319. Accordingly, we direct Public Service and Staff of the Commission[344] to work together with interested parties to discuss this topic at a CIM. The discussion could include information regarding what stakeholders are interested in, what attributes are desired, the potential structure of such a program, the status of Public Service's efforts on this topic, and what the next steps are. We are hopeful that this CIM could be convened in late February or early March.

[343] Boulder's Comments, p. 18.
[344] This could be either Trial Staff or staff of the Commission's Research and Emerging Issues group.

S. Requests not Explicitly Addressed

320. The Commission has weighed the information and filings from all parties and public commentors in balancing its policy and reaching the various decisions set out in this Phase II Decision. To the extent this Phase II Decision does not expressly address requests made by Public Service or an intervening party, such requests are denied. However, these requests were considered in balancing our considerations and reaching our ultimate conclusions in this Proceeding.

II. ORDER

A. The Commission Orders That:

1. After consideration of the statutory factors and other relevant factors, modifications to the Clean Energy Plan (CEP) presented by Public Service Company of Colorado (Public Service) are necessary to ensure that the Commission's approval of the CEP is in the public interest.

2. In accordance with the discussion above, we authorize Public Service to pursue the modified CEP and the acquisition of the resources included in the Alternative Portfolio with further due diligence and contract negotiations. Public Service shall further file applications for Certificates of Public Convenience and Necessity for all Company-owned generation resources arising from the modified CEP. Public Service's actions, consistent with this Decision, shall be presumed to be prudent at the time of cost recovery consistent with 4 *Code of Colorado Regulations* (CCR) 723-3-33617(d) of the Commission's Rules Regulating Electric Utilities.

3. All Company-owned generation resources arising from the modified CEP are subject to both the cost to construct performance incentive mechanism (PIM) and the operational PIM, in accordance with the discussion above.

4. The proposed transmission network upgrades, grid strength reinforcements, reactive power investments, and voltage support investments presented in the 120-Day Report are not part of the approved CEP. Additional review of the proposed transmission projects is necessary and, accordingly, 4 CCR 723-3-3206 is waived as to the transmission projects arising from this Proceeding, in accordance with the discussion above.

5. In accordance with the discussion above, Staff of the Colorado Public Utilities Commission (Staff) shall also initiate a stakeholder process with the Colorado Office of Utility Consumer Advocate and the Colorado Energy Office and in conferral with Public Service to bring forward a scope of work for hiring an independent transmission analyst as soon as reasonably feasible but no later than the commencement of the 2024 Just Transition Solicitation (JTS) proceeding. If this independent transmission analyst cannot be engaged in time for Phase I of the 2024 JTS, we direct the Company to include certain transmission-related portfolios in its direct case, in accordance with the discussion above.

6. As part of its application regarding attribution of costs between the CEP rider (CEPR) and the Renewable Energy Standard Adjustment, the Company shall address the recovery of specific activities based on the approved resource portfolio and the appropriate level for the CEPR to be initiated on January 1, 2025, in accordance with the discussion above.

7. With respect to the 2024 JTS, Public Service shall confer with Staff prior to the 2024 JTS to develop more robust modeling processes, clearly set forth the Company's proposed non-negotiable PPA terms in its Phase I 2024 JTS filing and provide in the 2024 JTS a comprehensive long-term rate analysis in addition to our other directives in accordance with the discussion above.

8. Public Service and Staff of the Commission shall work together to present at an upcoming Commissioners Information Meeting the interest in, potential structure of, and current efforts to develop a voluntary emissions reduction program, in accordance with the discussion above.

9. The 90-day deadline for a written Phase II Decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan set forth in 4 CCR 723-3-3613(h) is waived.

10. To the extent requests are not addressed in this Decision, they are denied.

11. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

12. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETINGS December 6, 13, and 20, 2023.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay
of Public Interest Organizations

Exhibit 2-165
Colorado Commission Decision No. C25-0024

Decision No. C25-0024

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0141E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN.

COMMISSION DECISION GRANTING, IN PART, AND DENYING, IN PART, THE MOTION TO APPROVE THE CLEAN ENERGY PLAN DELIVERY PLAN

Issued Date: January 14, 2025
Adopted Date: December 16, 2024 and December 20, 2024

TABLE OF CONTENTS

I. BY THE COMMISSION 3
A. Statement 3
B. Procedural History 4
C. Background of the CEP Delivery Motion 10
D. Component 1, Stage 1 12
1. Party Positions 12
2. Findings and Conclusions 18
a. PPA Projects 18
b. Utility-Owned Projects 20
E. Component 1, Stage 2 24
1. Party Positions 24
2. Findings and Conclusions 29
F. Other Component 1 Issues 33
1. Selection of Additional Solar and Solar Plus Storage Bids 33
2. Presumption of Prudence for Incremental Cost Increases 34
G. PPA Execution and Requests for Rule Variances 35
1. Party Positions 35
2. Findings and Conclusions 37

Colorado PUC E-Filings System

H. JTS Proceeding 39
1. Party Positions 39
2. Findings and Conclusions 41
I. Replacement for Bid 0235 42
1. Party Positions 42
2. Findings and Conclusions 47
J. Thermal Resource Price Increases 51
1. Party Positions 51
2. Findings and Conclusions 54
K. Bid 0989 56
1. Party Positions 56
2. Findings and Conclusions 57
L. Bid 0011 59
1. Party Positions 59
2. Findings and Conclusions 62
M. Purchase of Plains End 63
1. Party Positions 63
2. Findings and Conclusions 65
N. Alternative Thermal Proposals 66
1. Party Positions 66
2. Findings and Conclusions 67
O. Expansion of ISOC Incentives 67
1. Party Positions 67
2. Findings and Conclusions 69
II. ORDER 70
A. The Commission Orders That: 70
B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING December 16, 2024, and December 20, 2024. 71

I. BY THE COMMISSION

A. Statement

1. On September 6, 2024, Public Service Company of Colorado ("Public Service" or the "Company") filed a Motion to Approve Clean Energy Plan ("CEP") Delivery Plan and for Variances from Certain Commission Rules and Decisions ("CEP Delivery Motion").

2. Through this Decision, the Commission grants, in part, and denies, in part the CEP Delivery Motion. Our Decision allows the generation and storage projects included within the CEP to continue advancing despite changing market dynamics and geopolitical uncertainties, including importantly potential future changes in federal law. Advancing these generation and storage projects as part of the overall determinations made through the course of this Proceeding moves Colorado forward towards achieving aggressive state emission reduction targets. At the same time, while some amount of price flexibility is necessary, particularly given reliability and emission reduction considerations, our Decision also balances this price flexibility with several protections to ensure the CEP comes at a reasonable cost to customers. These protections include a two-stage process for clean energy projects that caps the amount of price relief and permits intervenor and Commission review as well as using existing regulatory processes for additional investigation and review of price increases associated with utility-owned projects. Similarly, this Decision finds that the record and abbreviated process associated with the CEP Delivery Motion are insufficient to make certain requested findings regarding additional thermal capacity and proposals to modify a demand responses ("DR") program. As set forth below, the Company is in no way prohibited from making appropriate filings to move these or other endeavors forward, particularly as it ensures reliability.

3. These determinations provide a process in consideration of the CEP Delivery Motion enabling timely review should federal changes in law arise that impact bid pricing, concurrent with guidance towards longstanding Commission processes. This careful balance and necessary flexibility to move towards significant emission reduction targets, while protecting Colorado ratepayers, including by allowing ongoing scrutiny, particularly of utility-owned projects not yet demonstrated as warranting a presumption of prudence.

B. Procedural History

4. Public Service initiated this Proceeding by filing its Verified Application for Approval of its 2021 Electric Resource Plan ("ERP") and CEP on March 31, 2021.

5. On August 3, 2022, the Commission issued Decision No. C22-0459 ("Phase I Decision"). Among other things, the Phase I Decision authorized Public Service to implement a competitive bidding process for acquiring cost-effective resources to meet its projected resource need from 2022 through 2028. The Commission also approved the process for evaluating bids to the competitive solicitation and established the modeling parameters, including inputs and assumptions, for the presentation and consideration of potential resource portfolios in Phase II of the Commission's ERP process. Pursuant to the terms of the Updated Non-unanimous Partial Settlement Agreement approved, in part, by the Phase I Decision, the Commission further authorized Public Service to initiate an interim ERP called the Just Transition Solicitation ("JTS") focused on meeting the projected resource need for the years 2029, 2030, and 2031.[1]

6. On January 23, 2024, the Commission issued Decision No. C24-0052 ("Phase II Decision"), approving the Company's CEP with modifications. Among other things, the Phase II

[1] Public Service filed an Application for Approval of its Just Transition Solicitation on October 15, 2024 in Proceeding No. 24A-0442E ("JTS Proceeding"). The JTS Proceeding is ongoing.

Decision authorized Public Service to pursue the acquisition of more than 5,800 MW of new storage and generation projects that were included in the approved resource portfolio with further due diligence and contract negotiations.[2] The approved resource portfolio includes 669 MW of thermal resources, consisting of four separate projects: Bid 0989 (a 200 MW Company-owned unit), Bid 0997 (a 200 MW Company-owned unit), Bid 0011 (a 50 MW unit that would be developed and constructed by a third-party but ultimately owned by the Company), and Bid 0235 (a 219 MW power purchase agreement ("PPA") unit). The Commission found that the inclusion of the PPA thermal resource (Bid 0235) was attractive in that it reduces the risk that customers will bear future costs associated with utility-owned gas resources, including the risks that utility-owned gas resources will become stranded.[3]

7. The Phase II Decision also established a cost-to-construct ("CtC") performance incentive mechanism ("PIM") for each utility owned generation and storage project in the approved resource portfolio. In the Phase II Decision, the Commission recounted how in other contexts, costs, performance, or scheduling issues have increased the costs of utility-owned projects relative to the initial estimates the Company provided.[4] The Commission opined that material changes to the cost and performance metrics of a project could impact the justification of the ERP need determinations. In addition, with competitive solicitation being the lynchpin of Colorado's ERP process, we opined that winning bidders should not be able to materially increase the price of bids without consequences.[5] To incentivize Public Service to build utility-owned projects at or below budget, the Commission established the CtC PIM that used the as-bid capital

[2] Phase II Decision, ¶ 92.
[3] Phase II Decision, ¶¶ 101 108.
[4] The Commission gave the specific example of the Company's representations in Phase I of the proceeding that the conversion of the Brush Coal Plant to burn gas would cost approximately $44 million. In the subsequent CPCN application, however, the Company's estimated costs had increased to $85 million. (Phase II Decision, ¶ 180).
[5] Phase II Decision, p. 125.

construction cost for each project as the baseline, set a five percent deadband around the baseline, and then set three symmetric tiers of costs sharing if the actual construction costs for a project were above or below the deadband.[6]

8. In the Phase II Decision, the Commission directed Public Service to file applications for Certificates of Public Convenience and Necessity ("CPCN") for all utility-owned resources within the approved resource portfolio. The Commission noted that, consistent with 4 *Code of Colorado Regulations* ("CCR") 723-3-3617(d) of the Commission's Rules Regulating Electric Utilities, Public Service's actions that are consistent with the Phase II Decision have a presumption of prudence.[7]

9. On March 13, 2024, the Commission issued Decision No. C23-0672 Addressing Applications for Rehearing, Reargument, or Reconsideration ("RRR") of the Phase II Decision ("First RRR Decision"). The First RRR Decision addressed several issues, including challenges to the approved resource portfolio, proposed modifications to the established CtC PIM, and the appropriate process for selecting backup projects. In addition, the First RRR Decision addressed the replacement of Bid 0235, which became unavailable after the Phase II Decision. The Commission specifically rejected the Company's request to replace Bid 0235 (a PPA project) with Bid 1000 (a utility-owned project). The Commission reiterated that diversifying the ownership of the gas resources can help reduce risks to ratepayers and expressed a strong interest in evaluating whether there were other PPA gas resources that could replace Bid 0235, such as Bid 0510, Bid 0514, and Bid 1061.[8]

[6] Phase II Decision, ¶¶ 183-185.
[7] Phase II Decision, p. 125.
[8] First RRR Decision, pp. 34-35.

10. On September 6, 2024, Public Service filed the CEP Delivery Motion, along with the testimony of Jack Ihle and several attachments. Among other things, the CEP Delivery Motion puts forth a proposed procedural schedule and limited discovery rights to facilitate the Commission's review of the Motion.

11. On September 10, 2024, Climax Molybdenum Company ("Climax") filed a Response to Public Service's proposed procedural schedule, which the Office of Utility Consumer Advocate ("UCA") and the Colorado Energy Consumers ("CEC") join. In the Response, Climax acknowledges the urgency of the CEP Delivery Plan but argues for extending the deadline for intervenor responses and increasing the amount of discovery that parties can propound. In its Response, Climax further states it prefers to proceed with an evidentiary hearing.

12. On September 19, 2024, the Commission issued Decision No. C24-0678-I. Among other things, Decision No. C24-0678-I set a procedural schedule that required the Company to file supplemental information, followed by intervenor responses, and a reply from Public Service to those responses ("Reply Comments"). Decision No. C24-0678-I also established limited discovery rights and scheduled a two-day *en banc* evidentiary hearing. The procedural schedule and discovery limits were a compromise approach that balanced the need for expediency and the concerns that certain intervenors raised regarding the deadline for intervenor responses and the amount of discovery rights afforded.[9]

13. By Decision No. C24-0699-I,[10] the Commission addressed both UCA's request to shorten the timeline for Public Service to respond to discovery and certain recommendations regarding Plains End (an existing PPA thermal resource). In addition, we invited the parties to

[9] Specifically, the concerns set forth in Climax's Response to Public Service's proposed procedural schedule. As set forth above, Climax argued for extending the deadline for intervenor responses and increasing the amount of discovery. UCA and CEC joined Climax's Response.

[10] Issued September 26, 2024.

comment on a proposed approach to maintain competitive tension and directed Public Service to provide additional information regarding certain wind and thermal bids.

14. On October 4, 2024, Public Service filed supplemental comments and information, pursuant to Decision No. C24-0678-I. Included in this supplemental filing was Hearing Exhibit 166, Attachment JWI-17. This Attachment is a detailed report on the status of all bids and includes information from the bidders regarding whether they are able to move forward with their as-bid pricing and the scope of price relief many bidders assert they need to move forward with their projects. Public Service submitted a revised version of this Attachment on November 1, 2024.

15. On October 11, 2024, the following intervenors filed Answer Testimony to the CEP Delivery Motion: Staff, the Colorado Energy Office ("CEO"), UCA, and the Colorado Solar and Storage Association and the Solar Energy Industries Association ("COSSA/SEIA"). In addition, the following parties filed Comments on the CEP Delivery Motion: the Colorado Independent Energy Association ("CIEA"), Interwest Energy Alliance ("Interwest"), Western Resource Advocates ("WRA"), and CEC.[11]

16. On October 3, 2024, Mainspring Energy, Inc. ("Mainspring"), filed an unopposed motion to intervene out of time in this Proceeding ("Late Intervention"). Mainspring is the developer of Bid 0011, which is a 50 MW new-build thermal resource in the San Luis Valley. Mainspring has been negotiating a build-transfer agreement with Public Service in which the Company will ultimately own and operate Bid 0011. In its Late Intervention, Mainspring argues the CEP Delivery Motion could directly and substantially impact Mainspring.

[11] Climax as well as UCA support and join in CEC's comments.

17. By Decision No. C24-0736-I,[12] the Commission granted Mainspring's Late Intervention. The Commission found that Mainspring sufficiently demonstrated its interests in this Proceeding and noted that no party opposes the Late Intervention.

18. On October 11, 2024, Mainspring filed Answer Testimony from two witnesses.

19. In Decision No. C24-0746-I,[13] the Commission directed Public Service to provide additional information in its Reply Comments. The Commission required the Company's Reply Comments to include the relevant PPA and build transfer agreement provisions that would implement a change-in-law price relief mechanism as well as examples of the PPA provisions that allegedly pose an unacceptable level of risk to the Company.

20. On October 25, 2024, Public Service submitted its Reply Comments.

21. On November 1, 2024, Mainspring filed an unopposed motion requesting access to certain confidential and highly confidential information pertaining to Bid 0011 ("Unopposed Motion to Access Information").

22. By Decision No. C24-0805-I,[14] the Commission granted Mainspring's Unopposed Motion to Access Information.

23. On November 7, 2024, the Commission held a remote evidentiary hearing at which the following exhibits and associated attachments were admitted: Hearing Exhibits 166, 509, 1205, 2202, 2204, 2709, 2710, 2711, 2712, 2713, 2714, 2715, 2716, 2717, 2718, 2719, 2720, 2721, 2722, 2723, 2725, 2904, 3000, and 3001.

24. On November 18, 2024, the following parties filed statements of position ("SOPs"): Public Service, Staff, UCA, CEC,[15] CIEA, COSSA/SEIA, Interwest, Mainspring, and WRA.

[12] Issued October 11, 2024.
[13] Issued October 16, 2024.
[14] Issued November 6, 2024.
[15] Climax supports and joins CEC's SOP.

25. The Commission deliberated on the CEP Delivery Motion at the December 16, 2024 Commissioner's Deliberations Meeting ("CDM") and the December 20, 2024 CDM.[16]

C. Background of the CEP Delivery Motion

26. In the CEP Delivery Motion, Public Service argues that global and national geopolitical and market forces require some adjustments to the CEP to ensure the generation and storage projects contemplated in the approved resource portfolio can move forward.[17] Public Service categorizes its requests into three components. Component 1 consists of a two-stage process in which renewable energy and storage projects could request price relief.[18] Under this process as initially proposed, developers (including the Company) could individually submit requests to a newly appointed Independent Auditor ("IA") to increase the price of their projects based on things such as unexpected supply chain difficulties, recent changes in tariff policy, or future changes in federal law. The IA would then verify whether the requested price increase is justified and submit its verification decision to the Commission for review.[19]

27. Under Stage 1 of this first component, developers could base price increase requests on a broad set of circumstances such as known and pending tariffs or duties, supply chain issues, or any other impacts of current market conditions such as changes in costs of materials or labor.[20] As proposed in the CEP Delivery Motion, developers could receive Stage 1 price relief of up to six percent increase of the as-bid pricing. Under Stage 2 of Component 1, developers could submit price increase requests to the IA based on a specified changes in federal law such as new tariffs or

[16] The procedural history and background of this case are more fully set forth in the Phase II Decision and the First RRR Decision. Here, we provide only that background and procedural history necessary for this Decision.
[17] CEP Delivery Motion, p. 2.
[18] Hr. Ex. 166 (Ihle), p. 35.
[19] Hr. Ex. 166 (Ihle), pp. 40-41.
[20] Hr. Ex. 166 (Ihle), pp. 35-36.

the reduction or repeal of the currently available production tax credits ("PTCs") or investment tax credits ("ITCs").[21] Developers could receive additional price relief in Stage 2 up to a total of 15 percent, inclusive of any Stage 1 relief. Thus, if a project received a six percent price relief in Stage 1, it would only be eligible for up to an additional nine percent increase in Stage 2.[22]

28. Component 2 addresses the thermal resources contemplated in the approved resource portfolio. Similar to the renewable energy and storage projects in Component 1, Public Service argues that the thermal resources need price increases to address disruptions to supply chains, strong demand for thermal unit components and labor, and the length of time that has elapsed since the bids were initially submitted on March 1, 2023.[23] Public Service seeks the ERP presumption of prudence per Rule 3617(d) that moving forward with the thermal units at the new revised cost levels is prudent. In addition, Public Service asks that the CtC baseline for the utility-owned gas facilities be adjusted upward to match the new cost estimates.[24]

29. Component 2 includes the Company's request for Commission approval to replace Bid 0235 with Bid 1000. Bid 0235 (a 219 MW new-build PPA gas resource) was included in the approved resource portfolio but is no longer available. The Company also seeks authorization to not include the selective catalytic reduction ("SCR") system that it originally planned for Bid 0989 (a 200 MW, utility-owned gas unit).[25]

30. As an alternative to Components 1 and 2, Public Service suggests the Commission treat utility-owned projects as "a distinct portfolio." Under this alternative, the projects in the utility-owned portfolio would keep the same construction costs that the Phase II Decision

[21] Hr. Ex. 166 (Ihle), p. 52.
[22] Hr. Ex. 166 (Ihle), p. 51.
[23] Hr. Ex. 166 (Ihle), p. 57.
[24] Hr. Ex. 166 (Ihle), pp. 57-58.
[25] Hr. Ex. 166 (Ihle), pp. 88-89.

contemplates, but instead of several project-specific PIMs, there would be one portfolio-wide PIM with a five percent deadband.[26] PPA projects could continue to seek price relief under the proposed Component 1 process.[27]

31. In Component 3, the Company requests approval to take certain actions to address near-term resource adequacy concerns by increasing capacity. Specifically, the Company requests a PPA extension for Plains End (a 219 MW unit with a PPA that expires at the end of 2027)[28] and increasing the incentives in the interruptible service option credit ("ISOC") program in an attempt to boost DR capacity.[29] Initially, Public Service also requested as part of Component 3 an extension of Bid 1061 (a 76 MW PPA thermal resource).[30] However, Bid 1061 subsequently became unavailable.[31]

D. Component 1, Stage 1

1. Party Positions

32. As initially presented, in Stage 1 of Component 1, both utility-owned and PPA clean energy resources could obtain price increases of up to six percent due to current market conditions. To receive such pricing relief, developers would submit requests and supporting information to the IA, and the IA would make a project-specific determination of whether the price increase is legitimate reasonable or whether it was due to an unreasonably low bid estimate. In their SOPs, however, several parties, including Public Service, Staff, CIEA, and COSSA/SEIA argue the Commission should fundamentally modify the proposed Component 1, Stage 1 process by eliminating the IA review process.

[26] CEP Delivery Motion, pp. 2-3.
[27] Hr. Ex. 166 (Ihle), p. 90.
[28] Hr. Ex. 166 (Ihle), p. 114.
[29] Hr. Ex. 166 (Ihle), p. 101.
[30] Hr. Ex. 166 (Ihle), pp. 112-13.
[31] Hr. Ex. 166 (Attachment JWI-16), p. 20.

33. Public Service specifically recommends that the Commission apply a uniform one to three percent price increase, without further IA reviews. Public Service "suggests 2 percent but defers to the independent power producer ("IPP") trade associations on the specific level of relief."[32] For wind projects, Public Service recommends the Commission apply a six percent price increase.[33] PPA projects would receive the approved price increase if the bidder can provide an affidavit of a corporate officer for the IPP bidder supporting the causes of the price increase. Any project that takes a Stage 1 increase would remain eligible for a Stage 2 change-of-law adjustment, and no increase could exceed 15 percent in aggregate, as initially proposed in the CEP Delivery Plan.[34]

34. For utility-owned clean energy projects, Public Service "would provide sworn testimony in support of the increase to the CtC value in the CPCN proceeding…."[35] The individual PIMs would be built around this updated CtC value and the CtC baseline would be entitled to a presumption of prudence in the follow-on CPCN proceeding.[36] For the three utility-owned wind projects in particular, Public Service makes clear in its SOP that the Company's sworn testimony in the CPCN proceeding would support an increase in the CtC value, "which may not exceed 6 percent."[37] Consistent with its initial proposal, Public Service argues that the price increases should be based on the $/MWh or $/kW-month PPA rates for IPP projects and should be based on the construction costs for utility-owned projects.[38]

[32] Public Service's SOP, p. 2.
[33] Public Service's SOP, p. 2.
[34] Public Service's SOP, p. 8.
[35] Public Service's SOP, p. 8.
[36] Public Service's SOP, pp. 8, 13.
[37] Public Service's SOP, p. 8.
[38] Hr. Ex. 166 (Attachment JWI-16), p. 13.

35. CIEA also recommends eliminating the use of the IA and instead requiring IPPs to submit affidavits signed by corporate officers supporting each CEP Project's repricing request. IPPs would provide the affidavits to Public Service, who could report the information to the Commission. Under this "fast-track" approach, CIEA would support a technology-specific reduced pricing flexibility of an up to three percent increase for solar, storage, or hybrid projects and up to six percent pricing flexibility for wind projects.[39]

36. As support for this position, CIEA argues that "[d]elay is the enemy" and that each month of delay causes cost increases.[40] CIEA argues that under Public Service's initially proposed IA process, the IA might not realistically complete its review of repricing submittal until approximately April 2025.[41] CIEA asserts that "the benefits of rigorous project pricing flexibility oversight via an IA and more regulatory process are outweighed by the risks of further increased project costs and decreased generation for resource adequacy in 2027 and 2028 due to project withdrawals or inability to meet as-bid [commercial operation dates]."[42]

37. COSSA/SEIA similarly argues against the IA approach in Stage 1. COSSA/SEIA acknowledges the IA may offer checks and balances and provide additional information but argues the IA process will introduce at least four additional months of delay.[43] Instead, COSSA/SEIA recommends the Commission authorize a three percent across-the-board price increase for solar, solar plus storage, and storage projects now based on the record associated with the CEP Delivery Motion filings. COSSA/SEIA argues this will avoid additional delays and price increases that could occur between now and March 2025. COSSA/SEIA states that it "is confident that increasing

[39] CIEA's SOP, p. 3.
[40] CIEA's SOP, p. 7.
[41] CIEA's SOP, p. 8.
[42] CIEA's SOP, p. 11.
[43] COSSA/SEIA's SOP, p. 3.

bid pricing by this amount will allow projects to get across the finish line toward contract execution."[44]

38. COSSA/SEIA questions the accuracy of the developer survey answers reflected in Hr. Ex. 166, Attachment JWI-17, Rev. 1, which reports the status of all of the projects and the scope of the requested price increases. COSSA/SEIA asks the Commission to refrain from exclusively relying on the information within this attachment, suggesting that the information is inaccurate and outdated.[45]

39. In its SOP, Interwest supports any plan that meets certain attributes that would help provide a quick path to project finalization. For Stage 1, Interwest's desired attributes include eliminating or minimizing the timeline and complexity of any IA process or additional regulatory review and incentivizing projects to sign agreements as soon as possible.[46]

40. In its SOP, Staff recommends adopting CIEA's initial proposal in which clean energy resources could request a price increase of between two to six percent by submitting affidavits of corporate officers to the Company, and the Company would then confirm this repricing in a compliance filing to the Commission.[47] Projects that do not require Stage 1 price relief should be expedited, remain eligible for Stage 2 relief (change of law), and could receive a one percent price increase without verification. Staff argues this option represents the best overall

[44] COSSA/SEIA's SOP, p. 11.
[45] COSSA/SEIA's SOP, pp. 6-7.
[46] Interwest's SOP, p. 1.
[47] While CIEA modified its position somewhat in its SOP, it initially proposed allowing IPPs to receive a price increase up to six percent in Component 1, Stage 1 without any IA review, with the understanding that such Stage 1 price increases could later be clawed back in Stage 2. Developers who are willing to execute PPAs right away could qualify for a one percent price increase without bidirectional Stage 2 exposure. (CIEA's CEP Delivery Response Comments, pp. 17-18).

approach to achieving price relief and that eliminating the IA will accelerate the development of all renewable projects.[48]

41. If the Commission moves forward with this approach, Staff argues two clarifications are necessary. First, the approach applies both to PPAs and utility-owned projects. For utility-owned projects, the Company would submit a filing with the Commission attesting to the need for the price increase. Second, Staff recommends the Commission specify that this price relief approach applies to projects in the approved portfolio. Only after an approved project has failed and the Company has gone through the established process for advancing backup bids could a backup bid also be eligible for Stage 1 price relief.[49]

42. In connection with its recommendation to approve pricing relief in Stage 1, Staff argues that the Commission should treat utility-owned generation and PPAs the same by applying a six percent price relief limit to the project's net present value ("NPV") for both ownership types as opposed to a six percent NPV for PPA projects and a six percent CtC baseline increase for utility projects. Staff argues the Commission should ignore the Company's protests and fashion the price relief for both PPAs and utility projects such that it is based on the NPV of the projects.[50]

43. In contrast to the parties arguing for the elimination of the IA, UCA recommends the Commission approve Public Service's initial Stage 1 proposal, including that the potential six percent cost increase would be confirmed by an IA.[51]

44. CEC asserts that the Commission must find a path forward that emphasizes transparency and scrutiny of any further cost increases. CEC does not oppose Public Service's initial proposal for an IA process so long as the IA process "is transparent and the results and IA

[48] Staff's SOP, pp. 3-4.
[49] Staff's SOP, pp. 4-5.
[50] Staff's SOP, pp. 6-7.
[51] UCA's SOP, p. 1.

decisions are subject to stakeholder investigation and challenge…."[52] In contrast, CEC "strongly opposes any proposal that would result in unnecessary and unverified automatic price increases not subject to scrutiny or verification through the IA or a similar process."[53] CEC specifically includes in this opposition proposals to provide uniform cost increases to encourage projects to move forward, especially for those projects that have indicated that no price increase is necessary.[54]

45. CEC reasons that, while the Company's initial proposal is not perfect, the third-party verification provided by the IA provides necessary customer protections and eliminate frivolous or unnecessary price increases.[55] CEC asserts that it is clear from the record that many solar and solar plus storage projects report the ability to execute PPAs at the as-bid PPA rate, assuming they could potentially obtain price relief from future changes of law.[56] CEC acknowledges the timing constraints but maintains the Company and Commission still have a responsibility to protect customers by providing cost increases only for actual and verifiable purposes and not provide unnecessary price increases.[57]

46. More specifically, CEC argues the Commission and Staff should have a role in selecting the IA to ensure that the IA is truly independent from the Company and bidders. In addition, CEC recommends expanding the process for Commission approval of an IA decision. CEC suggests that the 21-day review period be expanded and include an opportunity for intervenor

[52] CEC's SOP, pp. 1-2.
[53] CEC's SOP, p. 2.
[54] CEC's SOP, p. 2.
[55] CEC's SOP, p. 4.
[56] CEC's SOP, p. 4.
[57] CEC's SOP, p. 5.

comment before the Commission must issue a decision to ensure that interested stakeholders have an opportunity to review, audit, and weigh in on any proposed price increase. [58]

2. Findings and Conclusions

a. PPA Projects

47. The record contains considerable evidence that the current market dynamics and geopolitical environment have evolved since bids were submitted in March 2023 and factors such as supply chain constraints, policy uncertainty, and increased demand for clean energy projects have contributed to upward cost pressures.[59] Moreover, we agree with assertions from parties such as CIEA that further delay may cause additional price increases. We ultimately conclude that some amount of price flexibility is necessary to appropriately balance considerations of reliability, emissions reductions, and ensuring reasonable costs to customers.

48. The Commission agrees with Public Service, Staff, CIEA, COSSA/SEIA, and Interwest that the proposed IA-review process should be rejected for purposes of Component 1, Stage 1. The IA process will almost certainly result in several months of additional delays,[60] and additional delays will likely result in further price increases. Moreover, it is unclear how beneficial an IA would be in balancing the limited increases sought in Component 1, Stage 1 given the complexities of evaluating a variety of projects on an abbreviated basis. The risks that such a process would ultimately result in higher costs and the loss of important clean energy projects outweighs the benefits of a more robust project-by-project review of requested price increases. This is especially true for PPA projects, which do not require a subsequent CPCN proceeding.

[58] CEC's Comments on CEP Delivery, pp. 5-6.
[59] *See, e.g.*, Hr. Ex. 166 (Ihle), pp. 10-24.
[60] COSSA/SEIA's SOP, p. 3.

49. Thus, PPA solar, solar plus storage, and storage projects may receive a maximum price increase of one percent in Stage 1. The PPA wind project may receive up to a six percent price increase. This Stage 1 price relief flexibility for the PPAs is supported by the record evidence including the Company's testimony during the evidentiary hearing and especially the highly confidential updated pricing information contained in Hearing Exhibit 166, Attachment JWI-17, Rev. 1.

50. To receive the Stage 1 price increase, PPA developers must present to Public Service affidavits signed by corporate officers providing narrative descriptions supporting the requested increase and agreeing to the bidirectional nature of Stage 2 and the fact that Stage 1 and Stage 2 relief is considered in the aggregate. In other words, projects that receive a Stage 1 price increase could be subject to a price decrease in Stage 2.[61] Additionally, any Stage 1 price increase counts against the 15 percent cap on price increases possible in Stage 2. Thus, if a project obtains a six percent price increase in Stage 1, it would only be eligible for an additional nine percent price increase based on change of law in Stage 2. Projects that move forward without Stage 1 price relief would still be eligible for Stage 2 price increases but would not be subject to any Stage 2 price decreases. This strikes the balance of allowing bidders to move forward with contracts immediately if they currently have no price increase needs but allows for them to return if there is a change of law that significantly impacts their ability to deliver the project at the bid price. For clarity, and consistent with Staff's position, backup projects may also utilize the Stage 1 price relief mechanism but only after full efforts have been made to move forward with the approved projects and after the approved backup bid selection process is employed.

[61] This is directionally consistent with CIEA's initial proposal in which developers would "agree to the terms of a 'bidirectional' claw back of Stage 1 increases in its PPA, as well as liability for fraudulent statements." (CIEA's Comments, p. 17).

51. We recognize the arguments from CEC, UCA, and Climax that across-the-board price increases risk unnecessarily increasing costs to ratepayers and might constitute an unreasonable windfall for developers at ratepayer expense. However, a lengthy project-specific review might also unnecessarily increase costs through additional delay and threaten the viability of multiple clean energy projects, which could raise additional resource adequacy concerns. The cap on Stage 1 price increases together with the bidirectional nature of Stage 2 and the aggregate 15 percent cap for Stage 1 and Stage 2 price increases help weigh these concerns and reduce the risk that projects will obtain an unnecessary price increase in Stage 1. Further, our decision to defer consideration of the requested price increases for utility-owned projects until the CPCN proceedings as discussed below is consistent with arguments that there must be a project-specific review of each price increase.

b. Utility-Owned Projects

52. Given the differences between utility-owned projects and PPA projects, the Commission finds it appropriate to adopt a different Stage 1 approach for utility-owned clean energy projects. Contrary to Public Service's request, we defer granting a presumption of prudence for the proposed price increases or modifying the CtC PIM baselines until the appropriate CPCN proceedings. The Commission and interested stakeholders will be able to evaluate the validity of the requested price increases during the CPCN proceedings in much the same way that Public Service initially anticipated the IA would evaluate price increases. Because Public Service must still obtain CPCNs for the clean energy projects for which it now seeks price relief, withholding approval of the price increases until the CPCN proceedings will not result in any meaningful delay nor the associated concerns about additional price increases and resource adequacy related to further delay, making this distinct from the procedural path for PPA projects.

Moreover, it appears that Public Service is prepared to file CPCN filings for its wind projects in the near future. During the hearing, the Company represented that CPCNs for Bid 1015 and Bid 1024 should be filed about a week after hearing, while the CPCN for Bid 1029 would be filed in early December.[62]

53. Our decision to defer consideration of the requested price increases for utility-owned clean energy projects is similar to the requests of Staff and CEO for the Commission to defer consideration of price increases for the Company's thermal units,[63] and is directionally consistent with Public Service's alternative proposal for those thermal projects.[64] As determined in the respective CPCN proceedings, costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and operational PIM baselines. For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing may potentially constitute extraordinary circumstances within the terms of the CtC PIM (*i.e.*, unforeseen costs that could not have been known at the time the bid was made), subject to future adjudication by the Commission following development of the relevant project. Similarly, although potentially less applicable, the same would be true for the operational PIM. Moreover, prudently incurred costs associated with each of the projects will be eligible for recovery; provided, however, that this in no way impacts the application of the PIMs. For instance, the Company may earn a disincentive under the CtC PIM regardless of whether the underlying costs are imprudent.

54. In addition to the above findings, we clarify that utility-owned clean energy projects are subject to the same price cap as the respective PPA projects. Thus, the Company-owned wind

[62] Hr. Tr. November 7, 2024, pp. 138-39.
[63] Staff's SOP, p. 9; Hr. Ex. 1204 (CEO Response Testimony), pp. 20-21.
[64] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 19.

projects are only eligible for up to a six percent Stage 1 price increase in the CPCN proceedings, consistent with the Company's SOP,[65] and the utility-owned storage project would only be eligible for up to a one percent Stage 1 price increase in the CPCN proceeding. Importantly, this maximum six percent increase and maximum one percent increase shall be applied to the NPV of the respective projects, consistent with the price increases permitted for PPAs, and not on the CtC as the Company requests.

55. On this last point, we find Staff's arguments persuasive. Public Service's proposal to apply the percentage price increase to the project's construction costs for utility-owned clean energy projects but only to the NPV for PPA projects puts utility projects and PPA projects on an unlevel playing field. This unequal treatment could result in utility-owned projects receiving a larger price increase than an otherwise equivalent PPA project.[66] Public Service's own filings demonstrate the issue. A six percent increase on the construction cost of a wind project "translates to a higher percentage increase when compared to the smaller PTC-adjusted cost."[67] More precisely: "the 'six percent of baseline' cost increase divided by a smaller denominator (the PTC cuts approximately half of the cost of the project) ends up at about 12 percent on the PTC-adjusted costs."[68]

56. Public Services raises several arguments against Staff's proposal to limit the percentage price increases to an NPV basis, none of which are persuasive. For instance, the Company argues there are material distinctions between utility-owned and PPA projects and that converting an NPV adjustment to a new CtC baseline is complex.[69] While we agree that material

[65] Public Service's SOP, p. 8.
[66] Hr. Ex. 2709 (Staff Response), p. 20.
[67] Hr. Ex. 166, Attachment JWI-16 (Supplemental Comments), p. 13.
[68] Hr. Ex. 166, Attachment JWI-16 (Supplemental Comments), p. 13.
[69] Hr. Ex. 166, Attachment JWI-19 (Reply Comments), pp. 9-10; Public Service's SOP, p. 7.

differences exist between utility-owned and PPA projects, the Company has not established how any of these differences justify additional price flexibility for utility-owned projects. Public Service knew of these differences and presumable accounted for them when the Company formulated its Phase II bids that now serve as the baseline for the Company's projects. As for the complexity of converting an NPV adjustment to a new CtC baseline, Staff asserts that the Company "grudgingly admits" that it could calculate the NPV for utility projects. According to Staff, all of the necessary information to perform this calculation is contained in the project-by-project updated revenue requirements that Staff obtained in discovery.[70] Moreover, interested parties and the Commission will be able to work through these details in the follow on CPCN proceedings.

57. In its Reply Comments, Public Service makes two alternative requests if the Commission adopts Staff's NPV approach. First, the Company states the NPV approach results in reduced CtC baselines and thus asserts the Commission should modify the methodology used to calculate the incentives and disincentives under the CtC PIM. Specifically, the Company requests the Commission adopt the progressive method as opposed to the landing spot method.[71] Second, the Company argues the Commission should "convert the maximum NPV increase (such as 6%) to a revised CtC for each project, thus setting a new baseline CtC now and avoiding the need for recalculating NPV in the future."[72]

58. We decline to adopt the Company's two alternative requests at this time. Regarding the first request, in the First RRR Decision we rejected the Company's request to switch to the progressive method on the basis that doing so would significantly reduce the level of potential incentives and disincentives under the CtC PIM.[73] In its CEP Delivery Motion filings, the

[70] Staff's SOP, pp. 6-7.
[71] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 11.
[72] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 10.
[73] First RRR Decision, ¶¶ 122-23.

Company does not address this shortcoming with the progressive method. Consistent with our earlier

First RRR Decision, in the CPCN proceedings Public Service may request to implement the progressive method in such a way that is supported and roughly maintains the respective amounts of incentives and disincentives.

59. Similarly, we defer the Company's second request to convert the NPV increase to a revised CtC baseline to the respective CPCN proceedings. In the CPCN proceedings, the Commission and parties can evaluate the actual reasons behind the Company's price increases and the appropriate amount of price relief. The Company's suggestion may be reasonable, but it is unnecessary and premature to rule on the proposal at this time.

E. Component 1, Stage 2

1. Party Positions

60. As proposed, Stage 2 of Component 1 would allow developers to seek additional price relief based on changes of federal law. The Stage 2 process would be initiated by a motion filed by the Company, Staff, or by the Commission on its own motion, describing the change in law and explaining why Stage 2 relief is appropriate. After considering responses to the motion, the Commission would determine whether to initiate a Stage 2 relief process. After Stage 2 is initiated, any requests for relief must be completed through submittal to the IA no later than December 31, 2025, or 18 months prior to the project's commercial operation date ("COD"), whichever is later.[74] In addition, bidders would be required to submit requests and documentation to the IA within 30 days of any Commission decision approving Stage 2 relief. After the IA makes its verification, it would then submit all materials to the Commission. The Commission would

[74] Hr. Ex. 166 (Ihle), p. 52.

have 21 days to review the IA's verification and, at the Commission's discretion, suspend the requested relief. If the Commission suspended the requested price relief, then there would be a 10-day intervenor comment period, a seven-day Company and bidder response period, and a Commission decision to approve or reject the requested relief within 14 days after the Company response.[75]

61. Stage 2 relief would provide up to a 15 percent total price increase, inclusive of any prior approved increase in Stage 1.[76] Stage 2 is also bidirectional. For example, if PTC/ITC benefits increase, or if current tariffs are repealed, the Company could file for a reduction to the underlying PPA rates (for IPP bids) and CtC PIM baseline costs (for self-build and build-transfer bids).[77]

62. In the event the Commission or the IA rejects all or a portion of a requested and verified Stage 2 increase, a project with an executed PPA would be able to terminate the PPA and receive a 75 percent refund of its Security Fund under Article 11 of the Model PPA if it so elects within 14 days of the Commission decision. Similarly, a build-transfer project could terminate its contract with the Company by paying 25 percent of the Termination Payment.[78] Public Service proposes to implement the Stage 2 process by incorporating the proposed PPA language in Hearing Exhibit 166, Attachment JWI-20.

63. Although Public Service proposes to eliminate the IA in Stage 1, in its SOP the Company continues to support the Stage 2 IA process as initially presented. Public Service reasons that the IA concept "continues to have merit in Component 1, Stage 2, where the time pressures may not be as acute as the current ones and where the required assessments would be more discrete

[75] Hr. Ex. 166 (Ihle), pp. 43, 53.
[76] Hr. Ex. 166 (Ihle), p. 51.
[77] Hr. Ex. 166 (Ihle), p. 51.
[78] Hr. Ex. 166 (Ihle), p. 53-54.

and less subjective."[79] Public Service "requests approval of a Stage 2 process for all PPA and [utility-owned] projects with the same timing and triggers as proposed in the CEP Delivery Plan."[80]

64. In its SOP, Public Service argues the Stage 2 price relief mechanism "would not cover all potential changes in law, such as a full and immediate repeal of the Inflation Reduction Act ("IRA") or repeal of relevant tax credits made available or extended by the IRA."[81] The Company states it is committed to working with developers to address such scenarios, including how posted security is treated under these types of circumstances. In addition, Public Service requests guidance from the Commission as to whether it anticipates using an IA for determining price changes in the event Stage 2 is triggered. The Company asserts an IA could assist the Commission in confirming the project-specific impacts of changes of law in an objective, expedient manner that would significantly reduce the burden on the Commission.[82]

65. In Staff's SOP, Staff largely agrees with the Stage 2 price relief concept. Staff argues that whether Stage 2 price relief is permitted and the level of that price relief should be at the Commission's discretion, up to a maximum of 15 percent inclusive of Stage 1 relief. Consistent with CIEA's initial recommendation, Staff argues that Stage 2 price relief should be bidirectional, except for those projects that agree to go forward with only a one percent increase in Stage 1. For those projects, Stage 2 price relief should only be upward.[83] CEO likewise generally supports the Company's proposed process for Stage 2 pricing relief.[84]

66. In its SOP, CIEA argues for a more generous Stage 2 price relief structure. CIEA reasons the election has changed the calculus regarding the likelihood and scope of potential

[79] Public Service's SOP, p. 6.
[80] Public Service's SOP, p. 14.
[81] Public Service's SOP, p. 14.
[82] Public Service's SOP, p. 16.
[83] Staff's SOP, p. 16.
[84] Hr. Ex. 1204 (CEO Response Testimony), p. 17.

changes of law. According to CIEA, projects that move fast may lock-in existing PTCs, but further delays risk changes of law.[85] While CIEA continues to support the general concept of an IA review of change of law impacts in Stage 2, it argues that several modifications are now necessary. CIEA states it is "imperative" that the Commission allow developers to recover 100 percent of their security payments if projects must withdraw due to a change in law that causes cost increases of over 15 percent for any project. CIEA asserts that if the PTC/ITC is repealed, costs could rise by 100 percent. CIEA similarly argues that even short of a full repeal, partial repeals or changes in tax credit values or tariff amount could all devastate clean energy projects.[86]

67. If the PTC/ITC is repealed or a change in law results in a price increase of more than 15 percent, CIEA also asks that the Commission request full repricing from all CEP projects without the 15 percent Stage 2 limit.[87] CIEA further asks that the Commission extend by one year the December 31, 2025, deadline for bidders to request Stage 2 price relief. CIEA states that changes in law are likely to pass in 2026, so the deadline should be December 31, 2026.[88] CIEA does not oppose the bidirectional nature of Stage 2 but argues developers should be allowed to defend against a downward Stage 2 reduction by showing that their projects did not benefit from a price reduction.[89] Finally, CIEA provides redlined modifications to Public Service's proposed PPA language in Hearing Exhibit 166, Attachment JWI-20. CIEA makes it clear that it "does not request Commission approval of such modified language but provides the redline as an example to demonstrate IPP concerns about potential large, more structural changes of law that now must be taken into account."[90]

[85] CIEA's SOP, pp. 14-15.
[86] CIEA's SOP, p. 16.
[87] CIEA's SOP, p. 5.
[88] CIEA's SOP, pp. 5, 15.
[89] CIEA's SOP, p. 5.
[90] CIEA's SOP, p. 5.

68. In its SOP, COSSA/SEIA strongly supports the Stage 2 price relief for changes in law. COSSA/SEIA further supports retaining an IA to review any requests for Stage 2 price relief, reasoning that "there will be more time for successful bidders to request price relief, for the IA to review the request, and for the Commission to approve that price relief."[91] Nevertheless, COSSA/SEIA does request changes to the Stage 2 process. COSSA/SEIA asks for an appeals process in which a developer could request Commission review of a price increase that is denied by the IA. COSSA/SEIA asserts the appeal should take place in a separate Commission proceeding so that individual developers could seek Commission review of an unfavorable IA decision.[92] COSSA/SEIA also argues against the PPA language Public Service proposes in Attachment JWI-20. COSSA/SEIA asserts the Company's current language forces developers to bear all the risk, including losing their security deposit, if the IA or the Commission denies the requested price relief. COSSA/SEIA does not propose specific changes but asks that the Commission "adopt language that directs the Company to renegotiate bid security terms in any situation where Stage 2 price relief is denied by the Commission."[93]

69. More generally regarding PPA provisions, COSSA/SEIA argues the Commission "should refrain from making any determinations regarding the reasonableness or acceptability of any particular PPA provision."[94] COSSA/SEIA particularly cautions against any Commission finding related to the security provisions in Hearing Exhibit 166, Attachment JWI-21. COSSA/SEIA argues that PPA terms cannot be viewed in isolation but must be seen in the context of the larger give-and-take negotiation.[95]

[91] COSSA/SEIA's SOP, pp. 3-4.
[92] COSSA/SEIA's SOP, p. 4.
[93] COSSA/SEIA's SOP, p. 4.
[94] COSSA/SEIA's SOP, p. 6.
[95] COSSA/SEIA's SOP, p. 5.

70. Interwest argues that quick decision making and a fair and robust opportunity for project developer level input is critical if there are any future changes in law or tariff.[96]

71. In its SOP, UCA recommends the Commission approve the Company's plan for a potential 15 percent price increase in Stage 2.[97] UCA opposes, however, the Company's proposal to partially refund security deposits or other walk-away provisions. UCA reasons that security deposits provide a substantial incentive for developers to go forward with their projects or to minimize the requested price increase. UCA argues that developers knew their security deposits were at risk when they submitted their bids, and the security deposits should not be reduced or lost.[98]

2. Findings and Conclusions

72. The general concept of a Stage 2 process to addresses changes in law has widespread party support and appears to be critical for most, if not all, of the clean energy projects.[99] The Company's proposed Stage 2 process is a useful structure that will encourage developers to move forward with projects even though future tariffs or changes to tax credits might impact the projects' financials. Therefore, the Commission adopts the Company's proposed Stage 2 process for both PPA and utility-owned projects, subject to the below modifications and clarifications.

73. Although a project-specific IA review in Stage 1 is inappropriate for the reasons discussed above, we agree with several of the parties that an IA review in Stage 2 appears useful and efficient. We find persuasive the Company's arguments that an IA review has merit in Stage 2, "where the time pressures may not be as acute as the current ones and where the required

[96] Interwest's SOP, p. 3.
[97] UCA's SOP, p. 9.
[98] Hr. Ex. 509 (UCA Testimony), pp. 26-27.
[99] Hr. Ex. 166, Attachment JWI-17, Rev. 1.

assessments would be more discrete and less subjective."[100] Consistent with the Company's request in its SOP for more guidance regarding the role of the IA, we clarify that the IA will ideally provide independent analysis of the documentation provided by the various developers and will produce initial determinations as to whether price modifications are appropriate. The methodology underlying these determinations should be consistent across all relevant projects, regardless of technology or ownership type.

74. To ensure the IA is ready and available if and when needed, Public Service shall confer with Staff and UCA on the selection of an IA and development of a scope of work. The Company must submit a motion to approve the proposed IA together with an IA scope of work no later than March 31, 2025. Public Service's proposal to defer costs associated with the IA and recover them through the ECA seems reasonable, but Public Service must set forth the specifics of its proposed cost recovery mechanism in the March 31, 2025 motion. Parties to this Proceeding would have 14 days to file any responses to the Motion. Establishing this process at the outset will hopefully save time if and when Stage 2 is triggered.

75. Consistent with CEC's arguments for additional transparency, the Commission finds that certain modifications to the proposed IA review process are necessary. First, intervenors should have an opportunity to review and comment on the IA's Stage 2 determinations prior to a Commission decision. Intervenors shall have 21 days to review the IA's initial determination. Public Service and any impacted developer would then have seven days to file response comments. The IA's determination would not go into effect until the Commission decision, which would be issued in due course.

[100] Public Service's SOP, p. 6.

76. We generally agree with the Company that any requests for Stage 2 relief should be submitted to the IA no later than December 31, 2025, or 18 months prior to the project's COD. We empathize, however, with concerns from CIEA that changes in law might occur in 2026. Thus, while we adopt the Company's proposed deadline at this time, parties may petition for an extension as necessary.

77. Consistent with our discussion above, we emphasize that the Stage 2 process is bidirectional for any projects that received Stage 1 price relief. Projects that did not pursue and receive Stage 1 price relief are still eligible for Stage 2 relief, but only in the upward direction.[101] We agree with CIEA that pricing relief obtained in Stage 1 would be "[s]ubject to downward adjustment in Stage 2."[102] We further agree with CIEA, however, that developers are permitted to argue via the established Stage 2 process that their projects should not be subject to a price reduction.

78. We recognize the importance of clarifying the consequences if a developer does not obtain the requested Stage 2 relief or if such relief is insufficient to address the change in law. The Commission adopts the Company's initial approach in which developers could terminate the PPA/build-transfer agreement if their Stage 2 price relief was denied and only pay 25 percent of the security deposit/termination payment, so long as the developer elects to do so within 14 days of the Commission decision. Adopting the contrary approach supported by CIEA and COSSA/SEIA and allowing developers to terminate their contracts with no financial consequences if any portion of their Stage 2 request is denied would incentivize all developers to request the full 15 percent price relief and would put significant pressure on the IA and Commission to approve

[101] Public Service's SOP, p. 15.
[102] CIEA's SOP, p. 6; *see also*, CIEA's Comments, p. 17.

the Stage 2 requests without modification. In contrast, requiring developers to pay at least 25 percent of the security deposit/termination payment incentivizes developers to move forward with the projects at or below the 15 percent price cap. PPA provisions that allow bidders to renegotiate bid security terms or walk away with more than 75 percent of the security deposit/termination payment if any portion of a bidder's Stage 2 request is denied would be contrary to this Decision.

79. While the Commission empathizes with UCA's request that developers be required to pay 100 percent of their security deposit if they withdraw, the Company's 25 percent threshold is a more balanced approach. UCA's request ignores the substantial uncertainty that future changes in law pose to CEP projects. Allowing developers to recover 75 percent of their security deposit/termination payment will encourage serious projects to execute PPAs/build-transfer agreements, despite the uncertain future.

80. A related issue is CIEA's argument that developers be allowed to recover 100 percent of their security payments if projects must withdraw due to a change in law that causes cost increases of over 15 percent for any project. In the event there is an established change of law that exceeds the 15 percent cap, we agree that developers should be allowed to terminate their PPAs and recover 100 percent of their security payments. Allowing this type of flexibility in the event of a significant change in federal law will again encourage developers to execute PPAs and attempt to develop their projects. To be clear, this full return of the security payment would not be allowed whenever a developer claims that a change in law increased prices by more than 15 percent. Rather, this option would only be available after a developer establishes to the

Commission's satisfaction that a project experienced a legitimate price increase of more than 15 percent and this price increase is directly caused by a change in law.[103]

81. We decline from approving at this time CIEA's request that the Commission request repricing from all CEP projects without the 15 percent Stage 2 cap if there is a significant change in federal law. At some point, the Commission may be better off allowing impacted CEP projects to fail and relying on the JTS to reestablish the market price for clean energy projects.

82. Finally, we find COSSA/SEIA's request to establish a separate appeals process for bidders to be unnecessary and duplicative of existing avenues. Under the Stage 2 process established above, bidders already have an opportunity to provide input in the seven-day response period.[104] With the established Stage 2 IA process and the Commission's existing provisions for third parties to file a complaint to initiate a new proceeding, we do not see the need to create an additional appeals process per COSSA/SEIA's request.

F. Other Component 1 Issues

1. Selection of Additional Solar and Solar Plus Storage Bids

83. In addition to its other arguments regarding Component 1, UCA argues the Commission should consider selecting additional solar and solar plus storage bids. UCA asserts the large increase in future capacity need shown in the Company's initial JTS filings in Proceeding No. 24A-0442E supports taking additional capacity in this Proceeding.[105] UCA recommends the Company investigate whether the lowest-cost solar and solar plus storage projects are able to go

[103] For purposes of determining whether a project can recover 100 percent of its security deposit, the 15 percent threshold is based on the project's initial as-bid price, even if a project obtains a price increase in Stage 1. For instance, if a project received a six percent price increase in Stage 1, the developer would still be required to show more than a 15 percent price increase due to a change of law—even though the project would only be eligible for a nine percent price increase in Stage 2.

[104] *Supra* ¶ 75.

[105] UCA's SOP, pp. 4-5.

ahead under the proposed price increases proposed in Component 1. UCA specifically focuses on Bids 0718, 0649 and 0651 (all solar projects) and Bid 0567 (a solar plus storage).[106]

84. The Commission denies UCA's requests to investigate whether additional solar and solar plus storage projects can move forward under the Component 1 price relief mechanism. It is far from clear on this record that the additional bids UCA flags could move forward under Component 1 or that there should be a presumption of prudence for their acquisition. For instance, it is uncertain whether the interconnections for these new projects could be timely achieved. While we ultimately deny UCA's recommendation, we note that Public Service could always seek authorization to pursue such additional projects outside of the JTS Proceeding, especially if the Company sees a potential cost-savings or reliability benefit.

2. Presumption of Prudence for Incremental Cost Increases

85. CEC raises the additional argument that any incremental cost increase in Component 1 should not be afforded the presumption of prudence per Rule 3617(d). CEC reasons the proposed Component 1 cost increases "would occur outside of the Commission's competitive solicitation rules" and thus any approved cost increases should be subject to prudence challenges.[107] CEC further argues that escalating CEP costs were foreseeable and predicted by the Independent Evaluator Report.

86. We reject CEC's argument regarding the application of Rule 3617(d). Given the competitive bidding process underlying the initial selection of these bids, the evidence put forth regarding the need for price increases, and the process and protections inherent in the Stage 1-Stage 2 mechanisms, price increases awarded under Component 1 will carry a presumption of prudence

[106] UCA's SOP, p. 6.
[107] CEC's SOP, p. 3.

per Rule 3617(d). This will help provide Public Service the regulatory certainty it needs to quickly pursue these clean energy projects and avoid future delays and cost increases.

G. PPA Execution and Requests for Rule Variances

1. Party Positions

87. In its CEP Delivery Motion, Public Service seeks variances from Rule 3613(i) and Rule 3613(j). Under Rule 3613(i), a utility must execute contracts for resources within 18 months after the utility's receipt of bids to receive the presumption of prudence per Rule 3617(d). This deadline was September 1, 2024. Public Service seeks a six-month extension so that the new regulatory deadline to execute contracts is March 1, 2025. [108] Under Rule 3613(j), a utility must file a proposal within 14 months after the receipt of bids that addresses the public release of all confidential and highly confidential information related to bids. The deadline for this filing was May 1, 2024. Public Service proposes to extend this deadline by at least 11 months to April 1, 2025. Public Service states that the bids are in a very sensitive state and may change based on the relief contemplated in the CEP Delivery Motion.[109]

88. CIEA, COSSA/SEIA, and Interwest all argue the Commission should act to prevent further delays in executing PPAs. CIEA asserts Public Service's delay in PPA executions is a contributing factor for the need for price increases and that Public Service appears to be "understaffed and overwhelmed."[110] In its Response Comments, Interwest states that "timeliness" is the most critical factor in achieving the goals of the CEP and that the available time to complete

[108] CEP Delivery Motion, p. 14.
[109] CEP Delivery Motion, p. 15.
[110] CIEA's CEP Delivery Comments, p. 20.

projects and meet CODs is becoming prohibitively short.[111] Interwest further asserts there have been significant delays during contract negotiations due to the Company's own action.[112]

89. To prioritize PPA execution going forward, CIEA recommends the Commission require Public Service to submit by December 31, 2024, a filing updating the Commission on all PPA negotiations, and every month thereafter. CIEA also suggests the Commission direct the Company to prioritize quicker PPA execution over holding the line on withdrawal "outs" and penalties for IPPs. That said, CIEA expressly asks that the Commission take no action on the specific terms of PPAs presented by Public Service at this time.[113]

90. COSSA/SEIA critiques the Company's requested variance of Rule 3613(i) in the context of delayed PPA execution. COSSA/SEIA argues that Rule 3613(i) puts pressure on the Company to execute PPA and build-transfer contracts swiftly. According to COSSA/SEIA, granting the Company's requested variance would reward "the bad behavior and foot-dragging that occurred from the Company not executing contracts in a timely manner."[114] COSSA/SEIA recommends the Commission deny the requested variance and reserve its decision to grant or deny the presumption of prudence until after the CEP Delivery bids are finalized.[115] In the alternative, COSSA/SEIA argues that if the Commission grants the variance, the revised deadline for compliance should be as short as possible and a firm deadline that is not subject to additional delays. COSSA/SEIA suggests the extended deadline should be December 31, 2024. COSSA/SEIA also asks that the Commission confirm that bid prices will become public on that date.[116]

[111] Interwest's Comments, pp. 2-3.
[112] Interwest's Comments, p. 6.
[113] CIEA's SOP, p. 7.
[114] COSSA/SEIA's SOP, p. 9.
[115] COSSA/SEIA's SOP, p. 9.
[116] COSSA/SEIA's SOP, pp. 9, 12.

91. In its Reply Comments, Public Service asserts it is negotiating in good faith with all bidders and warns the Commission against relying on the unattributed statements from COSSA/SEIA and CIEA. Public Service asserts several PPA are in near-final draft form and that this demonstrates the Company's ability to reasonably negotiate with IPPs. For other bids, Public Service says there are issues outside of the Company's control, such as a developer's need for price relief or insistence on receiving a Component 1, Stage 2 relief mechanism.[117] The Company states that negotiations of long-term, multi-million-dollar contracts are always challenging and that while it agrees on the importance of executing PPAs, the timeframe for these negotiations is not atypical.[118] The Company asserts that no IPP developers were able to execute a PPA given the need for either direct pricing relief or assurances of relief in the event of future changes in tariffs or the availability of tax credits.

92. Ultimately, Public Service proposes to submit monthly reports, beginning in January 2025, on the status of negotiations for all PPA and IPP build-transfer projects. The Company states that these reports will be similar in form to Table 1 in the Company's October 4 Supplemental Filing, Hearing Exhibit 166, Attachment JWI-16HC. The Company commits to continue this monthly reporting until all PPAs for the CEP are executed.[119]

2. Findings and Conclusions

93. The Commission agrees that timeliness is a critical factor for the CEP's success. Indeed, this urgency is one of the main factors supporting our decision to eliminate the IA process in Stage 1 of Component 1 for PPA projects. Our decisions providing bidders and the Company

[117] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 30.
[118] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 28; Public Service's SOP, pp. 16-17.
[119] Public Service's SOP, p. 17.

more certainty regarding Component 1 price relief processes and the extent to which bidders can recover their security deposit should also help accelerate the negotiation process.

94. Nevertheless, the Commission denies CIEA's suggestion to direct Public Service to prioritize quicker PPA negotiations over penalties if IPPs walk away from the PPA. Apart from our earlier decisions regarding the recovery of security deposits, we see little value in issuing vague directives to focus on executing PPAs at the expense of other contested terms. As to CIEA's request that the Commission take no action on specific PPA terms, we agree that there is no need for the Commission to approve specific PPA provisions at this time.

95. Regarding CIEA's request for monthly updates from Public Service on all PPA negotiations, it appears that Public Service largely agrees with this concept. Consistent with the proposals from CIEA and Public Service, we direct the Company to submit monthly reports in this Proceeding on the status of negotiations for all PPA and IPP build-transfer projects. These negotiation reports shall be due on the fifth of every month,[120] and will continue until all PPAs and build-transfer agreements for the CEP are executed. Public Service shall confer with the individual bidders on the negotiation status that the Company intends to provide in the negotiation report. Conferral confirmation must be provided in the report to the Commission.

96. Turning to COSSA/SEIA's opposition to the Company's requested variance of Rule 3613(i), we agree that Rule 3613(i) ideally should incentivize Public Service to execute PPAs swiftly. We disagree, however, with COSSA/SEIA's primary recommendation to deny the variance and defer granting a presumption of prudence until after bids are finalized. Removing regulatory certainty in this way might cause additional delays. COSSA/SEIA's alternative

[120] The first report requirement shall commence the fifth of each month following issuance of this Decision, with an initial report for January of 2025 provided as soon as practicable following issuance of this Decision.

recommendation of a December 31, 2024 deadline is not feasible. Therefore, we grant the Company's requested variance and adopt the March 1, 2025 deadline the Company proposes in the CEP Delivery Motion. We clarify, however, that any request to extend the March 1 deadline must be accompanied with a detailed description of Public Service's efforts specific to each individual PPA and build-transfer agreement. Similar to the monthly negotiation reports but with more detail, Public Service shall confer with the individual bidders on the information the Company intends to provide regarding efforts to finalize PPAs, and conferral confirmation must be included.

97. We also grant Public Service's variance from Rule 3613(j) regarding the public release of bid information. We agree with the Company that the bids are in a "sensitive state" and it is too soon to publicly release confidential information regarding such as bid prices. The April 1, 2025 deadline is a reasonable amount of time for Public Service to submit a proposal for the public release of such information.

H. JTS Proceeding

1. Party Positions

98. Several parties recommend the Commission take certain actions regarding the ongoing JTS Proceeding in light of the challenges presented in the CEP Delivery Motion. For instance, Staff argues that in the JTS Proceeding, the Commission should consider consequences for bids that have failed in this process from reappearing in the JTS Proceeding. Such consequences could include higher bid fees or stricter walkaway provisions.[121] Staff suggests the Commission consider consequences for bids that have failed in this process that reappear in the JTS Proceeding (*e.g.*, higher bid fees or stricter walkaway provisions). Staff does not

[121] Staff's SOP, p. 17.

recommend setting such consequences here but encourages the Commission to inform bidders that withdrawing an approved bid submitted in this ERP only to re-bid the same project in the JTS Proceeding may result in heightened review or financial scrutiny.[122] CEO similarly suggests that bids that receive Component 1 price relief only to pull out of this process and bid into the JTS Proceeding could be subject to higher bid security fees, stricter walk-away provisions, or other measures that will increase the surety of future contracts.[123]

99. UCA opines that the Company and the Commission have been lax in ensuring that IPPs are not advantaging Colorado's ERP system. UCA recommends that any projects that pull out of this Proceeding from this point forward be ineligible to bid in the JTS Proceeding.[124]

100. COSSA/SEIA and CIEA make sweeping suggestions for how to reform the JTS Proceeding. For instance, COSSA/SEIA suggests setting a deadline in the JTS Proceeding for the expiration of bid pricing after which bidders would be allowed to refresh pricing.[125] One of CIEA's suggestions is for the Commission to consider a "best and final" pricing opportunity in the JTS Proceeding for IPPs to sharpen their pencils and adjust pricing after the levelized cost screening.[126]

101. Interwest states that the extended timelines in the Proceeding are putting investment at risk. Interwest warns that if development risks in Colorado are not reduced in future solicitations by trimming delays "the state may risk losing its appeal as a key focus for renewable project development."[127] According to Interwest, it is critical for the Commission to be able to fully investigate the Company's management of the CEP resource solicitation such that the problems in this Proceeding are not repeated in the JTS Proceeding and that "[the Company's] rhetoric be

[122] Hr. Ex. 2709 (Staff Response), p. 26.
[123] Hr. Ex. 1204 (CEO Response Testimony), p. 16.
[124] Hr. Ex. 509 (UCA Testimony), p. 11.
[125] Hr. Ex. 2202 (COSSA/SEIA Response Testimony), pp. 34-36.
[126] CIEA's Response Comments, pp. 26-27.
[127] Interwest's Comments, p. 3.

reviewed through a factual lens."[128] Interwest accordingly requests that the Commission make numerous changes to the JTS Proceeding. For instance, Interwest ask that Public Service be required to submit a separate filing in its JTS Proceeding with an analysis of every point in the CEP where any delay could have been avoided and suggestions for preventing similar delays in the JTS Proceeding.[129] Interwest also recommends the Commission require Public Service to include a bid price expiration deadline and to develop a PIM that would reward Public Service for conducting timely portfolio reviews and executing contracts efficiently.[130]

2. Findings and Conclusions

102. We reject the various suggestions to use this Proceeding to set new requirements for the currently ongoing JTS Proceeding. The intervenors in the JTS Proceeding are welcome to propose modifications in that proceeding, where they can be adjudicated by all parties in the JTS Proceeding.

103. We similarly deny suggestions from Staff, CEO, and UCA that there should be some type of predetermined consequence in the JTS Proceeding if a bidder abandons a project that was proposed in this Proceeding given all the difficulties, delays, and challenges that have occurred. That said, parties in the JTS Proceeding are free to argue that a particular bidder or a bidder's pricing is unreliable because of past actions. The Commission will consider such arguments as they come before us, but we decline from using this Proceeding to decide how bidders in the JTS Proceeding will be evaluated.

[128] Interwest's Comments, pp. 3-4.
[129] Interwest's Comments, p. 7.
[130] Interwest's Comments, pp. 8-9.

I. Replacement for Bid 0235

1. Party Positions

104. In the CEP Delivery Motion, Public Service seeks authorization to replace Bid 0235 (a 219 MW new-build PPA thermal resource that was included in the approved resource portfolio but is no longer available) with Bid 1000 (a Company-owned thermal resource). The Company separately seeks authorization to extend the PPA for Plains End (an existing 219 MW PPA thermal resource) to add additional capacity to its system.[131] Public Service argues the additional capacity it seeks in the CEP Delivery Motion is reasonable given the already tight summer capacity positions the Company is facing. The Company further reveals it has updated its methodologies for the planning reserve margin ("PRM") and effective load carrying capability ("ELCC") values and is developing a new base load forecast in advance of the JTS. Based on these new assumptions, the Company asserts it is facing real and substantial capacity needs in the coming years.[132]

105. CEO opposes the Company's proposal and recommends the Commission approve the Plains End PPA extension as the replacement for PPA Bid 0235. CEO notes that in the Phase II Decision, the Commission approved 669 MW of nameplate thermal capacity via Bids 0989, 0997, 0011, and 0235. Public Service now asks that the Commission approve 869 MW of nameplate thermal capacity via Bids 0989, 0011, and 1000, and by extending the Plains End PPA contract.[133] CEO argues that the Company does not need to secure an additional 200 MW of capacity at this time.[134] CEO asserts that the Commission's decision should be based on the facts that have been litigated in the instant proceeding.[135]

[131] CEP Delivery Motion, p. 9.
[132] Hr. Ex. 166 (Ihle), pp. 106-10.
[133] Hr. Ex. 1204 (CEO Response Testimony), pp. 21-22.
[134] Hr. Ex. 1204 (CEO Response Testimony), p. 22.
[135] Hr. Ex. 1204 (CEO Response Testimony), pp. 26-27.

106. WRA similarly recommends that the Commission approve the Plains End PPA extension as a replacement for Bid 0235 instead of Bid 1000.[136] WRA raises significant concerns about the Company's thermal proposals but notes that due to the nature of this filing and associated procedural schedule, the Commission and parties are unable to effectively investigate the Company's claims regarding resource adequacy issues. According to WRA, there are significant differences in the Company's capacity position if it is viewed through the lens of the currently approved ELCC and PRM conventions, as compared to the Company's new and unvetted methodologies.[137] WRA characterizes the issues as follows: "should the Commission approve the acquisition of additional thermal capacity to address resource adequacy concerns outside the RAP of this proceeding, that are based on ELCC and PRM methodologies that have not yet been litigated."[138]

107. WRA argues that with the updated ELCC/PRM methodologies, Public Service is attempting to justify its proposal to extend the Plains End PPA and pursue a larger self-build thermal bid. WRA observes that one factor influencing the capacity position shortage under updated methodologies appears to be the updated treatment of DR resources. Under current conventions, where DR is treated as a load reduction, DR contributes between 651 MW to 787 MW of load reduction, depending on the year. Under the Company's new methodologies, however, DR is included in the generation category, with capacities ranging from 335 MW to 372 MW. WRA reiterates its claim that the Commission and parties have extremely limited evidence about the factors driving the Company's resource adequacy claims and how these factors manifest in the loads and resources table.[139]

[136] WRA Comments on CEP Delivery, pp. 8-9.
[137] WRA Comments on CEP Delivery, p. 10.
[138] WRA's SOP, pp. 2-3.
[139] WRA Comments on CEP Delivery, p. 14.

108. Staff is more deferential to the Company's obligation to evaluate the reliability of its generating portfolio but ultimately notes the same issues that CEO and WRA raise. In its Response Testimony, Staff acknowledges that the Company retains the obligation to evaluate the reliability of its generating portfolio but states that Staff struggles to see the need for additional thermal capacity in 2028. Staff implores the Company to provide a robust discussion of this issue in its responsive comments and asserts that, without such complete explanation, Staff will not support the acquisition of an additional 200 MW of thermal generation.[140] Conversely, Staff states it will support the Company's position if it can fully demonstrate and explain the reliability concern necessitating the acquisition of the additional 200 MW of thermal capacity.

109. In its SOP, Staff references the load and resources ("L&R") table from Volume 2 of the JTS that Public Service provides in its Reply Comments (JTS Table 2.9-1) as illustrating a significant capacity shortfall through 2033 (e.g., 646 MW in 2025 and 534 MW in 2026). Staff moreover asserts that this L&R Table underestimates the capacity shortfall in that some of the assumed CODs have been pushed back and a solar bid has failed.[141] Nevertheless, Staff stops short of endorsing the Company's proposal.

110. If the Commission determines that the Company has not provided sufficient support for its reliability concerns, Staff states there are two options. First, the Commission could retain the two thermal projects currently in the approved resource portfolio (Bid Nos. 0989 and 0997) and simply add Plains End. Second, the Commission could replace both Bid 0989 and 0997 with Bid 1000 as well as Plains End. Staff's preference is the second option, given that Bid 1000 appears more economical than Bid 0989.[142]

[140] Hr. Ex. 2709 (Staff Response), p. 35.
[141] Staff's SOP, p. 15.
[142] Staff's SOP, p. 15.

111. In its Reply Comments, Public Service asserts that using the Plains End PPA extension as the replacement for Bid 0235 is untenable. Public Service proffers two arguments in support of is position. First, the Company asserts that replacing a new-build thermal asset with the existing Plains End unit does not work from a reliability perspective. Second, the Company argues that forgoing new thermal capacity now is not an option given anticipated resource needs.[143] More bluntly, Public Service states that "[t]he Company will not sign the [Plains End] extension if doing so is conditioned on removing Bid 1000—the best available option to replace Bid 0235—from the portfolio, as some intervenors suggest."[144]

112. Regarding the need for a new-build combustion turbine ("CT") from a reliability perspective, Public Service asserts that it undertook the alternatives analysis the Commission required in its First RRR Decision for the replacement of Bid 0235 and that the preferred result is acquiring Bid 1000 as the replacement for Bid 0235. "Public Service strongly believes that a full portfolio of *new* thermal assets, i.e., at or near 669 MW, is required to continue the energy transition in a reliable manner."[145] The Company asserts an extension of the Plains End unit, which is 20 years old, "is not a substitute for a new CT unit, which the Commission has already approved."[146] Public Service further alleges that "[t]he approval of the acquisition of three new CTs in the Phase II Decision to meet reliability needs is a closed issue," noting that "[n]o party challenged this need on [RRR]."[147] The Company references the Phase II Decision in which the Commission stated that it "cannot simply carve out from a modeled resource portfolio some or all of the firm dispatchable resources that Public Service maintains are necessary for reliability."[148]

[143] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 17-18.
[144] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 26.
[145] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18 (emphasis in original).
[146] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 21.
[147] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.
[148] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 24-25 (quoting Phase II Decision, ¶ 125).

Similarly, Public Services references its earlier arguments in its Response Comments to the 120-Day Report when it stated that "eliminating gas units or taking the shortcut of substituting suboptimal and questionable short-term PPA extensions . . . makes the plan less reliable and risks reliability."[149]

113. On the other hand, Public Service emphasizes that it is not arguing against the Plains End PPA extension. The Company states that Plains End is valuable to the Company from capacity, black start, and transmission support perspectives.[150]

114. As to its argument that foregoing additional thermal capacity is not an option, Public Service argues that a five-year extension of Plains Ends is temporary and creates a hole that will need to be filled when the PPA expires. The Company asserts that it cannot count on any capacity from Plains End after the five-year extension expires, making the PPA extension "an inferior option from a reliability perspective."[151]

115. Referencing its direct case in the JTS Proceeding, Public Service asserts that it has substantial and growing capacity needs due to projected load growth and its revised ELCC and PRM studies.[152] Public Service acknowledges interveners' concerns that the JTS L&R table has not been litigated. Public Service argues, however, that "the appropriate question is not whether the updated load forecasts and ELCC and PRM studies have been approved, but whether it represents the best information available to the Company when making choices in a challenging environment."[153] Referencing the recently-filed JTS Proceeding, the Company states it is "confident of substantial needs for new generation—including both new renewable generation and

[149] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 26 (quoting Public Service's Response Comments to the 120-Day Report, pp. 28-29).
[150] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 26-27.
[151] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.
[152] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 27.
[153] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 27.

new firm dispatchable generation—above and beyond anything we have seen in Colorado."[154] Based on this new modeling, Public Service argues that it is prudent to approve the Company's Component 2 portfolio and to extend the Plains End PPA to meet demand in a dynamic environment. Conversely, the Company argues it would be imprudent to simply ignore the best-available information and hope that capacity needs will remain flat.[155]

116. In its SOP, Public Service maintains its position, arguing that it has performed an analysis of all available thermal alternatives and "the Commission has approved the need to build a total of three new [CT] units" in addition to a thermal project in the San Luis Valley.[156] Public Service also states that "Plains End is not a substitute for the new thermal capacity the Commission approved in Phase II."[157]

2. Findings and Conclusions

117. As presented through this CEP Delivery Motion process, Public Service has failed to meet its burden of proof that Bid 1000 is the appropriate replacement for Bid 0235. We therefore deny applying the ERP presumption of prudence under Rule 3617(d) to the Company's proposed replacement for Bid 0235. Instead, the presumption of prudence is limited to the combination of the Plains End PPA extension, Bid 0011, and *either* Bid 1000 or Bid 989 (discussed further below). If the Company insists that the extension of the Plains End PPA, Bid 0011, Bid 0989, *and* Bid 1000 are all necessary for reliability, it can proceed with that option and retain its burden to show in subsequent proceedings the prudency for the incremental thermal capacity (*i.e.*, Bid 1000 or Bid 989) and any associated costs.

[154] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18.
[155] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 28.
[156] Public Service's SOP, p. 9.
[157] Public Service's SOP, p. 11.

118. The arguments Public Service puts forth for why the Plains End PPA extension cannot be used to replace Bid 0235 are unpersuasive. Starting with the Company's assertions regarding reliability of Plains End compared to a new-build thermal resource, we note the Company raises no concerns with the location of the Plains End unit compared to the Bid 0235 nor points to any known reliability issues with Plains End. Indeed, Public Service states that the Plains End PPA extension "is valuable to the Company from capacity, black start, and transmission support perspectives…."[158] Instead of raising specific reliability concerns with Plains End, Public Service seems to argue that anything less than three *new* CTs is per se unreliable. For instance, the Company asserts that "[t]he approval of the acquisition of three new CTs in the Phase II Decision to meet reliability needs is a closed issue,"[159] and that "Plains End is not a substitute for the new thermal capacity the Commission approved in Phase II."[160] These statements imply that the Commission found in the Phase II Decision that approximately 650 MW of *new-build* thermal resources is necessary for reliability.

119. We disagree with the Company's characterization of our findings regarding new-build thermal resources. While the thermal resources within the approved portfolio were admittedly all new builds, for reasons unknown to the Commission, the Company did not identify the potential to extend the Plains End PPA as an option until the CEP Delivery Motion. Public Service cannot now argue that failure to include such PPA extensions in the approved portfolio is a finding that such resources are inappropriate. Indeed, existing PPA units *were* included in the approved backup thermal portfolio, and Public Service never contested that these approved backup resources could not replace a new-build resource. In fact, in the First RRR

[158] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 26-27.
[159] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.
[160] Public Service's SOP, p. 11.

Decision we rejected Public Service's request to replace Bid 0235 with Bid 1000 because there was no analysis as to whether the existing PPA units such as Bid 1061, Bid 0510, and Bid 0514 could serve as the replacement.[161] Public Service never sought RRR on this point.

120. Contrary to the Company's assertion that the existing Plains End unit cannot be a substitute for the new-build thermal resources initially in the approved portfolio, we see existing PPA units such as Plains End as providing valuable ownership diversity and protection from additional costs. In our Phase II Decision, we noted that Company-owned thermal resources subject ratepayers to the risk of construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will become stranded. We found the approved resource portfolio more desirable than the Company's preferred portfolio in part because the approved portfolio contained a PPA thermal resources, which "reduces the risks that customers will be saddled with future costs associated with Company-owned gas resources."[162]

121. The Company's second argument regarding growing resource adequacy concerns is also unconvincing. We acknowledge the Company's new L&R Table put forth in the JTS shows significant capacity shortfalls through 2033. Ultimately, however, we agree with CEO and WRA that our decisions regarding resource adequacy should be grounded in the evidence that has been litigated in this Proceeding. The resource need projections on which the Phase II Decision relies have been thoroughly vetted throughout this long Proceeding. We are disinclined from adopting the Company's eleventh-hour change in its resource adequacy forecasts as a justification to acquire an additional 200 MW of thermal resources.

[161] First RRR Decision, ¶¶ 77-78.
[162] Phase II Decision, ¶ 108.

122. To be clear, we are not prohibiting the Company from moving forward with the requested incremental thermal resources. We simply conclude that Public Service has not earned a presumption of prudence in this Proceeding, particularly based on the relatively truncated and late-stage process associated with the CEP Delivery Motion. If the Company is convinced it needs additional thermal resources above those approved in this ERP Proceeding, it has other methods of obtaining regulatory certainty before construction, including through a CPCN proceeding. Public Service is ultimately responsible for ensuring reliability. In this vein, we encourage Public Service to continue moving forward with actions it reasonably believes are necessary to ensure the Company has the resources it needs to ensure reliability. This may include, for example, development and permitting work associated with all of its proposed thermal resources.

123. As for the thermal resources for which the Company does enjoy a presumption of prudence, we ultimately provide the Company discretion to pursue either of the two options put forth by Staff. In Option 1, Public Service would enjoy a presumption of prudence for the following thermal resources: the Plains End PPA extension, Bid 0989, Bid 0997, and Bid 0011. In Option 2, Public Service would enjoy a presumption of prudence for the following thermal resources: the Plains End PPA extension, Bid 1000, and Bid 0011.[163]

124. We agree with Staff that Option 2 appears more attractive given the cost advantages of Bid 1000. Moreover, Option 2 avoids the complexities associated with Bid 0989 as discussed below. Nevertheless, we acknowledge there are additional factors that might impact the appropriateness of the two options, such as the timing of when various resources can come online

[163] If, for example, the Company decides to move forward with the Plains End PPA extension, Bid 1000, Bid 0011, *and* Bid 0989, then Bid 0989 would be incremental to Option 2 and thus would not enjoy a presumption of prudence. The other thermal resources would enjoy a presumption of prudence.

and the locational differences of the various resources. Based on the record before us, Public Service is in the best position to determine which option is preferable.

J. Thermal Resource Price Increases

1. Party Positions

125. As part of the CEP Delivery Motion, Public Service seeks the ERP presumption of prudence per Rule 3617(d) that pursuit of the thermal units at the new revised cost levels is prudent. In addition, Public Service asks that the CtC PIM baseline for the utility-owned thermal facilities be adjusted upward to match the new cost estimates.[164]

126. Several intervenors disagree with the Company's request regarding the proposed price increases of the thermal units. For instance, Staff recommends that the Commission not grant the Company the specific price relief, arguing there is simply not enough time and information to ascertain whether the requested relief is reasonable.[165] Staff's strong preference would be for the Company to present its financial analysis in the CPCN proceedings to appropriately allow parties time to examine the Company's estimates, changed circumstances, financial accounting, *etc*. Such CPCN proceedings could appropriately re-establish the individual CtC baselines after careful consideration of the detailed information.[166]

127. In its SOP, Staff argues that the "the Commission must insist upon properly vetting the significantly increased cost projections" and reiterates its recommendation to do so in follow-on CPCN proceedings.[167] Staff argues that Public Service provides little more than the "limited and cursory explanations for the increases in the right-hand column of Hearing

[164] Hr. Ex. 166 (Ihle), pp. 57-58.
[165] Hr. Ex. 2709 (Staff Response), p. 39.
[166] Hr. Ex. 2709 (Staff Response), p. 40.
[167] Staff's SOP, p. 9.

Exhibit 2718HC."[168] Staff further asserts that neither the Commission nor any of the intervenors have had an adequate opportunity to vet the reasons the Company gives for the surges in projected costs. [169]

128. In its Response Testimony, CEO similarly argues that Public Service has not provided detailed information demonstrating which costs have increased, by how much, and why. Without this information, CEO argues, the Commission cannot reasonably determine if the new baseline costs the Company proposes are reasonable. CEO asserts that more detailed cost comparisons and explanations should be provided in future CPCN proceedings, where any prudency requests can be addressed.[170]

129. Interwest recommends that the Commission require Public Service to treat all projects equally in the CEP Delivery Plan to ensure fairness, transparency, and system reliability. According to Interwest, utility-owned projects should be treated in the exact same manner as IPP owned generation, and thermal generation should be treated in the exact same manner as renewable generation. [171]

130. CEC and UCA argue the Commission should retain the project-specific CtC PIMs with no adjustment to the baseline. CEC asserts that modifying the CtC PIM at this juncture would fundamentally disrupt the purpose of the CtC PIM and set a precedent that utilities can simply dodge PIM disincentives if project costs increase. According to CEC, customers should be protected from the cost increases that the IE Report predicted.[172] UCA similarly argues the CtC

[168] Staff's SOP, p. 8.
[169] Staff's SOP, pp. 8-9.
[170] Hr. Ex. 1204 (CEO Response Testimony), pp. 20-21.
[171] Interwest's Comments, pp. 6-7.
[172] CEC's Comments on CEP Delivery, pp. 8-9.

PIM is intended to protect customers against price increases and thus it would be unreasonable to adjust the baseline for a CtC incentive for a price increase.[173]

131. In its Reply Comments, the Company continues to argue that application of Rule 3617(d) and its presumption of prudency to the updated costs for Bid 0989, Bid 1000, and Bid 0011 is appropriate. The Company reasons that it has presented updated pricing with more detail and background than is typically provided in a Phase II process, and this is an ERP where Rule 3617(d) applies to projects receiving approval. Public Service states that a presumption of prudence would provide the Company regulatory certainty to move forward with CPCN filings for these units where the costs can be examined in more detail and a final determination regarding the costs for the project, including the CtC baseline, can be established by the Commission. [174]

132. Nevertheless, the Company acknowledges that several intervenors raise concerns with this concept.[175] If the Commission declines to apply Rule 3617(d), the Company proposes an alternative pathway that it states is responsive to the proposals from Staff and CEO to use the CPCN proceedings reestablish the individual CtC baselines. The Company alternative proposal is for the Commission to make the following findings:

> Finding 1: Prudently incurred costs associated with each of the projects will be eligible for recovery.
>
> Finding 2: Costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and Operational PIM baselines, as determined in the CPCN proceeding.
>
> Finding 3: For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing are—if established by the utility to have cost impacts on the project as delivered compared to the CtC baseline—extraordinary circumstances within the terms of the CtC

[173] Hr. Ex. 509 (UCA Testimony), pp. 27-28.
[174] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 18-19.
[175] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18.

> PIM, subject to future adjudication by the Commission following development of the project in question. Similarly, although potentially less applicable, the same would be true for the Operational PIM.[176]

133. Public Service states that, in the absence of a Rule 3617(d) application to the updated cost estimates, making the above three findings offers an alternative path forward.[177]

134. In its SOP, Public Service does not discuss the alternative approach of making certain findings prior to CPCNs. Instead, Public Service argues the Commission should move forward with the Company's primary recommendation to approve CtC baseline adjustments consistent with the Company's presentation in the CEP Delivery Motion. The Company asserts that intervenors "have conducted extensive discovery relating to these projects over the last two months, and will have an opportunity for additional review in future proceedings as the projects are brought online."[178]

2. Findings and Conclusions

135. We agree with Staff and CEO that the requested cost increases for the thermal resources should be examined in follow-on CPCN proceedings before deciding whether the incremental costs are entitled to a presumption of prudence or warrant adjustments to the CtC PIM baseline. The Commission finds unpersuasive the Company's arguments that it has presented updated pricing with more detail and background than is typically provided in a Phase II process and thus is entitled to Rule 3617(d)'s presumption of prudence. In a typical Phase II process, there is competitive tension and various resource options. These elements are largely lacking in the context of the CEP Delivery Motion's requested price increases for thermal units. Moreover, it is

[176] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 19.
[177] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 20.
[178] Public Service's SOP, p. 9.

far from clear that Public Service has presented detailed information regarding the requested price increases; Staff's assertions support the opposite conclusion.[179]

136. On the other hand, we disagree with CEC and UCA's suggestions to decide in this Proceeding that no adjustments to the CtC baselines are warranted. Public Service appears to raise legitimate claims that thermal generating equipment has seen significant increases in demand and cost. If established in follow-on CPCN proceedings, such cost increases may warrant adjusting the CtC PIM baseline. Similarly, we decline from adopting at this juncture Interwest's position that thermal resources should be treated the same as renewables.

137. In connection with our decision to evaluate the proposed cost increases in the follow-on CPCN proceedings, we largely agree with Public Service's alternative proposal to make certain findings regarding how such cost increases will be evaluated going forward. The thermal projects that have earned a presumption of prudence in this Proceeding will advance to the CPCNs with this presumption of prudence intact as to the project's as-bid amounts. In the CPCN proceedings, the Commission could determine the incremental costs above the project's as-bid amounts potentially constitute extraordinary circumstances and accordingly adjust both the CtC baseline and the level of costs that carry a presumption of prudence.

138. For clarity, we adopt the Company's three requested findings, with the below modifications. As determined in the respective CPCN proceedings, costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and operational PIM baselines. For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing may potentially constitute extraordinary circumstances within the terms of the CtC PIM (*i.e.*, unforeseen costs that could not have been known at the time the bid was

[179] Staff's SOP, p. 8.

made), subject to future adjudication by the Commission following development of the relevant project. Similarly, although potentially less applicable, the same would be true for the operational PIM. Moreover, prudently incurred costs associated with each of the projects will be eligible for recovery; provided, however, that this in no way impacts the application of the PIMs. For instance, the Company may earn a disincentive under the CtC PIM regardless of whether the underlying costs are imprudent.

K. Bid 0989

1. Party Positions

139. As part of the CEP Delivery Motion, Public Service requests Commission approval to remove the SCR system from Bid 0989.[180] The Company argues the SCR system is not required for environmental permitting and that its removal will result in cost savings and operational advantages.[181]The Company explains that it initially assumed the unit would need an SCR to meet environmental permitting requirements. After further examination, based on permitting requirements, projected capacity factor and operating characteristics, Public Service now maintains that the SCR is not necessary and the unit can be permitted and operated without it. Public Service acknowledges that removing the SCR will likely lower the unit's permitted capacity factor, but the Company states that the lowered capacity factor is still above the range it expects to need for this unit.[182]

140. Public Service states it needs certainty from the Commission on this point in order to commence the air permitting process with the Colorado Department of Public Health and the Environment ("CDPHE"). Public Service asserts that if the Commission defers deciding whether

[180] CEP Delivery Motion, p. 9.
[181] Hr. Ex. 166 (Ihle), p. 75.
[182] Hr. Ex. 166 (Ihle), pp. 75-76.

to remove the SCR, the Company would need to proceed with the SCR for permitting reasons, which would result in "unnecessary costs to customers."[183]

141. In its SOP, Public Service clarifies that the Company is not asking the Commission to either approve anything regarding the permitting of Bid 0989 or approve operational characteristics for Bid 0989. Instead, "the Company simply requests the Commission acknowledge that moving forward without the SCR is permissible in light of the fact that this is a difference from the as-bid configuration."[184]

142. Staff argues the Commission should proceed with caution regarding the removal of the SCR device. Staff notes that the Company's Phase II modeling and bid assumed that an SCR would be installed for this unit. Staff is particularly concerned about the Company's representations regarding the capacity factor at which the unit can operate without the SCR. Staff argues the Commission should find a way forward in which it can quickly vet the Company's cost-reduction claims as well as to verify potential operational concerns associated with removing the SCR. To do this, Staff suggests the Commission direct parties to address the removal of the SCR as part of an operational PIM proceeding.[185]

2. Findings and Conclusions

143. We share Staff's concern that removing the SCR from Bid 0989 might change how Public Service can operate the unit as compared to the Phase II modeling. Public Service has testified, however, that the lowered capacity factor the unit would have without the SCR is not expected to change Public Service's use of the plant and that there is insufficient time to fully

[183] Hr. Ex. 166 (Ihle), p. 76.
[184] Public Service's SOP, p. 10.
[185] Staff's SOP, p. 11; Hr. Ex. 2709 (Staff Response), p. 44.

evaluate the operational changes before Public Service must initiate the permitting process with CDPHE.

144. Based on the Company's representations in testimony, the Commission grants the Company's clarified request in its SOP and acknowledges that moving forward without the SCR is permissible even though doing so is different than the as-bid configuration. Public Service has put forth evidence that removing the SCR will save ratepayers considerable money without interfering in the planned operation of the unit nor the value it is expected to provide ratepayers. CDPHE is tasked with determining the exact impacts that removing the SCR will have on the plant's operations.

145. Nevertheless, if Public Service moves forward with Bid 0989, the issues surrounding the SCR device will need to be more closely examined in the follow-on CPCN proceeding. Public Service's position that the SCR device is unnecessary is based on assumptions regarding how the Company will use the unit. However, there are several uncertainties that might impact the planned use of the unit, including developments with beneficial electrification, large new loads, and the potential entry into a regional market. If such changes alter the calculus for whether the additional operational flexibility granted by use of the SCR device is beneficial, the Commission will scrutinize whether any incremental costs should fall on Public Service's ratepayers.

146. Similarly, we intend to examine in any future CPCN for Bid 0989 whether there should be a mechanism (*e.g.*, a PIM) to ensure the accuracy of the Company's representations regarding the capacity factor of the unit and the role the unit has in the system. One of the primary purposes of thermal units such as Bid 0989 is to help ensure Public Service has the capacity it needs when the system is peaking. If the Company's removal of the SCR device were to impact

the unit's ability to serve its purpose, we would have significant concerns as to whether ratepayers are receiving the intended benefits of the unit and may find the need to guard against this eventuality at the onset of the project.

L. Bid 0011

1. Party Positions

147. Bid 0011 is a 50 MW thermal resource in Alamosa County. The project is being developed and built by Mainspring, but as bid, Public Service would purchase, own, and operate the unit. As with the other thermal units in the approved Alternative Portfolio, Public Service now seeks price flexibility regarding Bid 0011.[186] However, unlike the other thermal units, Bid 0011 claims designation as a "Section 123 resource" as explained in the Phase II Decision.

148. UCA recommends the Commission reject Bid 0011. UCA asserts the life of the Mainspring generators is unknown given that the Mainspring's first commercial units were deployed in 2020. UCA also points to hearing questions that show Mainspring only has about 20 MW of projects in the field.[187] UCA goes on to assert that the price of Bid 0011 is excessive and not competitive with other projects, especially if Bid 0011 fails to qualify for ITC tax benefits. As an alternative, UCA recommends the Commission approve extending the life of the existing Alamosa CTs as a bridge to the JTS.[188] UCA also suggests that some of the Plains End units could be moved to the San Luis Valley to replace the capacity from Bid 011 at a much lower cost.[189]

149. Mainspring submitted testimony that Bid 0011 would reduce CO2 emissions compared to the existing plants in Alamosa County by approximately 59 percent and NOx

[186] Hr. Ex. 166 (Ihle), pp. 27-28; CEP Delivery Motion, p. 9.
[187] UCA's SOP, pp. 6-7.
[188] UCA's SOP, pp. 7-8.
[189] Hr. Ex. 509 (UCA Testimony), pp. 20-21.

emissions by approximately 99 percent on a per MWh basis.[190] Mainspring further asserts that its linear generator technology has the ability to switch between various gaseous fuels, including, but not limited to, natural gas, hydrogen, propane, and biogas. The linear generator uses a low-temperature reaction without a spark or flame, which results in near-zero emissions of nitrogen oxides. [191] With its project's fuel flexibility and ability to seamlessly change fuels without hardware or software updates, Mainspring argues the project does not have stranded asset risk of traditional thermal units. [192]

150. Mainspring notes that when it developed its bid, it did not expect that Public Service would require a third-party engineering study, and the associated cost and schedule impacts were not reflected in the bid. Mainspring argues there are similar requirements related to Bid 0011's status as a Section 123 resource that have forced Mainspring to reasonably deviate from its bid assumptions and associated pricing.[193]

151. In its SOP, Mainspring reiterates the positive attributes of Bid 0011 and notes that due to the plant's new, clean technology, it is a Section 123 resource, to which the Commission must give the "fullest possible consideration to the cost-effective implementation" of the project.[194] Mainspring additionally argues that Bid 0011 will not unreasonably shift risk to ratepayers. Mainspring asserts it has the necessary experience deploying its linear generators, noting the other projects its development team has done and the fact that the Department of Energy recently awarded Mainspring an $87 million grant to build a manufacturing facility to produce its linear generators.[195] Mainspring also states the Commission and parties will be able to evaluate

[190] Hr. Ex. 3001 (Igo Testimony), p. 5.
[191] Hr. Ex. 3000 (Hennessy Testimony), pp. 4-5.
[192] Hr. Ex. 3000 (Hennessy Testimony), p. 8.
[193] Hr. Ex. 3001 (Igo Testimony), pp. 8-9.
[194] Mainspring's SOP, p. 7.
[195] Mainspring's SOP, p. 10.

the build-transfer agreement with Public Service in the CPCN proceeding. According to Mainspring, a core component of the negotiations with Public Service has been reducing risk for ratepayers. Mainspring further notes that it has made substantial investments in the project that will not be recoverable if the Commission ultimately does not approve Public Service's acquisition of Bid-0011.[196]

152. In addition, Mainspring argues that advancing Bid 0011 is the best available option to meet the needs of the San Luis Valley. If the Commission removes Bid 0011 in place of other options that were not competitively bid, Mainspring argues it would undermine the entire Phase II process and potentially chill future competitive solicitations in Colorado. Such a result would also arguably violate Commission Rule 3605(h)(II)(A), which provides that in an ERP proceeding, a Phase II decision "shall establish the *final* cost-effective resource plan."[197] Mainspring specifically critiques UCA's recommendation to move some of the Plains End units to the San Luis Valley as a replacement for Bid 0011. Mainspring asserts there is no analysis on the feasibility of this option and, because Plains End will emit more emissions than the linear generator, such a move would be contrary to the Commissions statutory obligation to account for and help correct the historical inequities faced by disproportionately impacted communities in Colorado.[198] Mainspring also adds the record does not support extending the life of the existing Alamosa CTs.

153. Although Staff initially recommended eliminating Bid 0011 due to its price increase, Staff changed its position after reviewing Mainspring's testimony. In its SOP, Staff now asserts the Commission "should no longer consider dropping Bid No. 0011."[199] Staff recommends the Commission vet the projected cost increases in the CPCN proceeding, arguing that determining

[196] Mainspring's SOP, p. 10.
[197] Mainspring's SOP, p. 13 (emphasis in original).
[198] Mainspring's SOP, pp. 13-14.
[199] Staff's SOP, p. 9.

whether the price increase drivers truly constitute justifiable projected cost increases is an ideal topic for a CPCN proceeding.[200]

154. In Public Service's SOP, the Company continues to recommend moving forward with Bid 0011 at the requested price increase. The Company appreciates Staff's recognition of the importance of Bid 0011. Public Service states that the alternative—life extensions of the existing units at Alamosa—is not preferable, given that they leave the same location-specific capacity hole after 2030.[201]

2. Findings and Conclusions

155. The Commission generally agrees with Public Service, Staff, and Mainspring. Consistent with the other approved thermal resources, Public Service may advance Bid 0011 to the CPCN proceeding, and Rule 3617(d)'s presumption of prudence will remain intact as to the project's as-bid amounts. The Commission will evaluate in the CPCN proceeding whether the incremental costs of the project also warrant a presumption of prudence and whether the CtC PIM baseline for the project should be adjusted as set forth above.

156. We reject UCA's recommendation to use the existing CTs as a bridge until new resources can be acquired in the JTS. The existing thermal resources in Alamosa are aging, and Public Service raised reliability concerns with these plants in the 120-Day Report. UCA's recommendation simply delays when a replacement thermal resource is constructed in Alamosa, with no guarantee that future thermal resources would be more cost effective. We likewise reject UCA's suggestion to move some of the Plains End units to the San Luis Valley. There is insufficient record support for this proposal.

[200] Staff's SOP, p. 10.
[201] Public Service SOP, p. 11.

157. Although Public Service may move forward with Bid 0011 consistent with the other approved thermal resources, we are concerned about the price and size of Bid 0011 and the associated risks to ratepayers. At the same time, we continue to acknowledge the potential fuel flexibility associated with this plant and the potential for benefits in that regard. Accordingly, we direct Public Service to present in the CPCN proceeding as a potential alternative an approach in which the size and costs of the project are reduced. As an example of this alternative option, the Company could consider structuring the build-transfer agreement more as a purchase option and pre-construction development asset with Mainspring. Under such an approach, the Company might have a unilateral option to purchase the project at an agreed upon matrix of prices, with flexibility to adjust the final size of the project. In return for this option, and in addition to the purchase price, the Company could compensate Mainspring for all of its verifiable reasonable third-party development costs at the time the option was signed. Public Service may be able to request accelerated cost recovery of these expenses through the electric commodity adjustment. We encourage the Company to explore and negotiate further this and other potential options regarding Mainspring, with the overarching intent of reducing costs and limiting risks to ratepayers.

M. Purchase of Plains End

1. Party Positions

158. In the CEP Delivery Motion, the Company states that its preferred approach is to extend the Plains End PPA. As a secondary approach, the Company suggests it could pursue purchasing the unit.[202]

[202] Hr. Ex. 166 (Ihle Testimony), p. 115.

159. In their Answer Testimony, Staff and UCA initially both urged the Commission to direct Public Service to purchase Plains End, arguing that purchasing the unit provides substantial cost advantages. UCA in particular characterized the cost-benefit of owning the plant as "massive."[203]

160. In its Reply Comments, however, Public Service argues that requiring the Company to immediately purchase Plains End is not a prudent path. The Company reasons that before purchasing an asset like Plains End, the Company would need to conduct extensive due diligence. Public Service states that it "could not commit to purchasing the unit prior to conducting due diligence without strong and unambiguous assurances that any unforeseen issues … would not be a basis for intervenor disallowance recommendations."[204] If the Company's preferred approach is approved, the Company proposes to report annually, beginning in the March 2025 ERP annual report, on the status of a potential acquisition of Plains End. [205]

161. After reviewing the Company's Reply Comments, UCA and Staff both change positions regarding the purchase of Plains End. In its SOP, Staff now argues against requiring Public Service to purchase Plains End. Staff instead recommends the Commission adopt the Company's preferred approach in which it extends the PPA. In connection with this recommendation, Staff argues the Commission should (1) require Public Service to carry out due diligence regarding the potential acquisition of the unit, and (2) direct the Company to seek Commission approval to purchase or decline from purchasing Plains End in an application filing that contains the Company's due diligence.[206]

[203] Hr. Ex. 2709 (Staff Response), pp. 29-30; Hr. Ex. 509 (UCA Testimony), pp. 16-17.
[204] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 22.
[205] Public Service's SOP, p. 12.
[206] Staff's SOP, p. 13.

162. UCA similarly recommends that Public Service extend the PPA and perform due diligence on the condition of the plant and the costs for the Company to operate it. Depending on the results of the due diligence, UCA recommends the Company purchase Plains End as soon as possible.[207]

2. Findings and Conclusions

163. We approve the Company's preferred approach of extending the Plains End PPA and then conducting due diligence into a potential acquisition of the unit. To be clear, as argued here, we find that the Company has met its burden and extending the Plains End PPA is entitled to a presumption of prudence.

164. Consistent with the Company's position, Public Service shall report annually, beginning in the March 2025 ERP annual report, on the status of a potential acquisition of Plains End. We also adopt Staff's additional proposal and require Public Service to carry out the due diligence and direct the Company to seek Commission approval to purchase or decline from purchasing Plains End in an application filing that contains the Company's due diligence.

165. While we ultimately agree with Public Service's preferred approach regarding Plains End, the Company's decision to wait until September 2024 to seek regulatory approval regarding Plains End is incredibly frustrating. If the Company would have brought Plains End to the Commission earlier, there might have been additional options for cost savings for ratepayers. There is insufficient information to address that concern raised by parties here. While the Company's preferred approach appears to be the only prudent presented option moving forward based on this record and at this very late stage, our determination only addresses prudency of extension given the record before us. In a subsequent proceeding stakeholders may argue whether

[207] UCA's SOP, p. 2.

Public Service fails to demonstrate the prudency of its decisions to delay seeking regulatory approval regarding Plains End.

N. Alternative Thermal Proposals

1. Party Positions

166. In its Response Testimony, UCA puts forth an alternative thermal proposal that includes Bid 1000 but then adds a another two CTs at an existing gas-fired generator station. UCA argues that adding CTs at this existing site provides important transmission support as an existing gas-fired generator, Cherokee 4, retires. UCA asserts that its thermal proposal provides 1,019 MW of economical thermal capacity.[208]

167. UCA continues to advance its alternative thermal proposal in its SOP, reiterating the importance of adding additional generation at Cherokee. Relatedly, UCA asks that the Commission direct Public Service to delay the Cherokee 4 retirement date by a year. UCA argues that delaying the retirement will improve the reliability of the Company's system and help address the projected capacity shortfall in 2028.[209]

168. CEC offers a similar, but broader, recommendation that the Commission consider extending existing thermal generation capacity as necessary to meet load growth and maintain reliability in the face of lost capacity from withdrawing clean energy projects. CEC asserts that Xcel Energy affiliate Southwestern Public Service Company has turned to extending thermal generating units as it transitions its generation fleet to meet New Mexico's emissions reduction goals. CEC argues the Commission should require Public Service to explore similar opportunities here.[210]

[208] Hr. Ex. 509 (UCA Testimony), pp. 20-21.
[209] UCA's SOP, p. 3.
[210] CEC's Comments on CEP Delivery, p. 8.

169. Another alternative proposal from UCA is that the San Luis Valley should have enough capacity to allow it to be "islanded" if the two transmission lines connecting the San Luis Valley are lost. UCA asks the Commission to direct Public Service to provide summer and winter load and gas-pipeline capacity data for the San Luis Valley, with the load data also showing how much load could be curtailed in case the transmission lines are lost. UCA recommends Public Service provide a plan for how much capacity, including gas, storage, and demand management, is needed to island the San Luis Valley if the transmission lines are lost.[211]

2. Findings and Conclusions

170. The Commission denies UCA's alternative thermal proposal and recommendation to require Public Service to delay the retirement of Cherokee 4. There is insufficient record support for UCA's proposals. We likewise decline CEC's recommendation to require Public Service to explore extending the lives of existing thermal units. Public Service is responsible for reliability and should already be evaluating all potential options to ensure resource adequacy.

171. We also do not support UCA's recommendation to require Public Service in this Proceeding to submit an analysis of the amount of additional capacity that would be necessary to island the San Luis Valley. UCA can always advocate for such an analysis in the JTS if it wishes to do so.

O. Expansion of ISOC Incentives

1. Party Positions

172. Public Service seeks authorization to increase the incentives under the ISOC program to encourage more DR capacity. Public Service argues that expansion of this program is most likely to produce incremental growth in short term DR. The ISOC program uses direct-load

[211] UCA's SOP, pp. 8-9

control and provides a minimum of ten minutes notice to customers prior to controlling the customer's load. Legacy or "grandfathered" customers receive a foundational bill credit of $15.97/kW-mo, but new customers currently receive a bill credit of only $11.27/kW-mo. At this lower incentive, however, Public Service states that only one customer has enrolled in the program since 2019.[212] The Company asks that the Commission increase the "new" program incentive to match the "legacy" incentive of $15.97/kW-mo through 2028.

173. CEO supports increasing the ISOC incentive back to its legacy level on a pilot basis with additional reporting. CEO reasons this will allow the Company to gather information about the willingness of customers to enroll in the ISOC program at the adjusted incentive level. CEO recommend the Commission direct Public Service to provide any learnings and data collected from the pilot both in its 2026 Demand Side Management ("DSM") Strategic Issues proceeding to assess the potential capacity impacts of the ISOC incentive and in its annual DSM Status Report.[213]

174. In its Response Testimony, UCA recommends the Commission reject the Company's proposal to expand the ISOC program, arguing Public Service has not provided enough information to enable the Commission to perform an adequate evaluation of its proposal. UCA specifically asserts Public Service has not provided the additional capacity that could be expected nor provided the additional cost of increasing program incentives.[214]

175. Staff likewise recommends rejecting Public Service's ISOC proposal. Staff argues the ISOC proposal does not belong in this Proceeding. Staff further asserts that since modifying the ISOC program requires changing the Company's interruptible service tariff, an advice letter filing is the proper vehicle for Public Service to seek approval of its ISOC proposal.[215]

[212] Hr. Ex. 166 (Ihle), pp. 118-19.
[213] Hr. Ex. 1204 (CEO Response Testimony), p. 30.
[214] Hr. Ex. 509 (UCA Testimony), p. 24.
[215] Staff's SOP, p. 14 (citing Hr. Tr. November 7, 2024, p. 261).

176. Public Service continues to advocate for its ISOC proposal in its SOP, reiterating that the ISOC proposal would increase incentives for "new" load from participants to match the "legacy" incentive rate of $15.97/kW-mo through 2028. Public Service anticipates that approximately 10 additional MW of ISOC capacity could become available if the legacy pricing is expanded.[216]

177. The Company argues that Staff's suggestion to evaluate the ISOC proposal through a separate advice letter filing could take an additional eight months and would not be an efficient use of the Commission's, the Company's, or intervenors' resources. Public Service argues the proposed change is incremental, the legacy pricing rate has already been vetted and approved, and the change would only be in effect through 2028 when all ISOC pricing can be reevaluated. Public Service also notes it has committed to reporting on the results of its proposal in the ISOC annual reports. Instead of a new advice letter proceeding, Public Service argues the Commission should approve the proposal here and implement it through a compliance advice letter filing.[217]

2. Findings and Conclusions

178. Although the potential for additional DR capacity is attractive and aligned with the Commission's broader intent, we ultimately deny Public Service's ISOC proposal. In this relatively abbreviated process associated with the CEP Delivery Motion, Public Service has not adequately supported its proposal. For instance, there has been insufficient evidence regarding the projected costs and benefits of the Company's proposed modifications to the ISOC program. For these reasons, Public Service will need to present a more fleshed out version of its proposal in a standalone advice letter proceeding.

[216] Public Service's SOP, pp. 15-16.
[217] Public Service's SOP, p. 16.

179. Public Service complains that requiring a separate advice letter proceeding could take an additional eight months. Based on the record in this Proceeding, however, the Company has not established that an eight-month delay in acquiring perhaps an additional 10 MW of capacity warrants deviating from the Commission's standard regulatory process. We direct Public Service to file its ISOC proposal as a separate advice letter as soon as reasonably practicable.

II. ORDER

A. The Commission Orders That:

1. The Motion to Approve Clean Energy Plan ("CEP") Delivery Plan and for Variances from Certain Commission Rules and Decisions filed by Public Service Company of Colorado ("Public Service") on September 6, 2024, is granted, in part, and denied, in part, consistent with the discussion above.

2. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

3. This Decision is effective immediately upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING December 16, 2024, and December 20, 2024.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-166
Tri-State January 2026 Press Release

Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order

tristate.coop/tri-state-makes-craig-generating-station-unit-1-available-operate-compliance-doe-emergency-order

01/23/26

(January 23, 2026 – Westminster, Colorado) To comply with an emergency order from the U.S. Department of Energy (DOE) under Section 202(c) of the Federal Power Act, Tri-State Generation and Transmission Association and the other co-owners of the Craig Generating Station took the necessary steps this week to make Unit 1 available to operate.

On Dec. 30, 2025, owners of the Craig Station received the emergency order from the DOE identifying an energy emergency in the Western Electricity Coordinating Council Northwest area and directing Tri-State to keep Unit 1 available to operate at the direction of either the Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, for the next 90 days.

Unit 1 went into an outage on Dec. 19, 2025, due to a mechanical failure of a valve. Tri-State and the other co-owners took the necessary steps to repair the valve in a timely manner and as noted, the unit was available to operate by Tuesday, Jan. 20, 2026.

Retaining Unit 1 in compliance with the order will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs. Tri-State continues to evaluate how best to comply while limiting the costs to its members, and the impacts to its employees and operations. Tri-State is not providing estimates at this time for the costs that may ultimately be necessary for compliance, including recent repairs, as it is working to prepare filings in support of cost recovery.

Craig Units 1 and 2 are part of the Yampa Project, jointly owned with multiple utility services providers including Tri-State, Platte River Power Authority, PacifiCorp, Xcel Energy and Salt River Project, with Tri-State as the operating entity. Tri-State owns 100% of Unit 3. Craig Unit 1's capacity is 427 megawatts. Unit 2, with a capacity of 410 megawatts, and Unit 3, with a capacity of 448 megawatts, are scheduled to retire in 2028.

Since 2016, Unit 1 has been scheduled for retirement by Dec. 31, 2025, for economic reasons, and to comply with numerous state and federal requirements. This retirement decision has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit's retirement.

About Tri-State

Tri-State is a power supply cooperative, operating on a not-for-profit basis, serving electric distribution cooperatives and public power district member-owners in four states. Together with our members, we deliver reliable, affordable and responsible power to more than a million electricity consumers across nearly 200,000 square miles of the rural West. Visit www.tristate.coop.

Contact

Amy Robertson, 303-254-3743, amy.robertson@tristategt.org

Mark Stutz, 303-254-3183, mark.stutz@tristategt.org

Certain information contained in this press statement are forward-looking statements including statements concerning Tri-State's plans, future events, and other information that is not historical information. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including those described from time to time in Tri-State's filings with the Securities and Exchange Commission. Tri-State's expectations and beliefs are expressed in good faith, and Tri-State believes there is a reasonable basis for them. However, Tri-State cannot assure you that management's expectations and beliefs will be achieved. There are a number of risks, uncertainties and other important factors that could cause actual results to differ materially from the forward-looking statements contained herein.

A Touchstone Energy® Cooperative 

©2026 Tri-State Generation and Transmission Association, Inc. Power supplier to the rural west.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

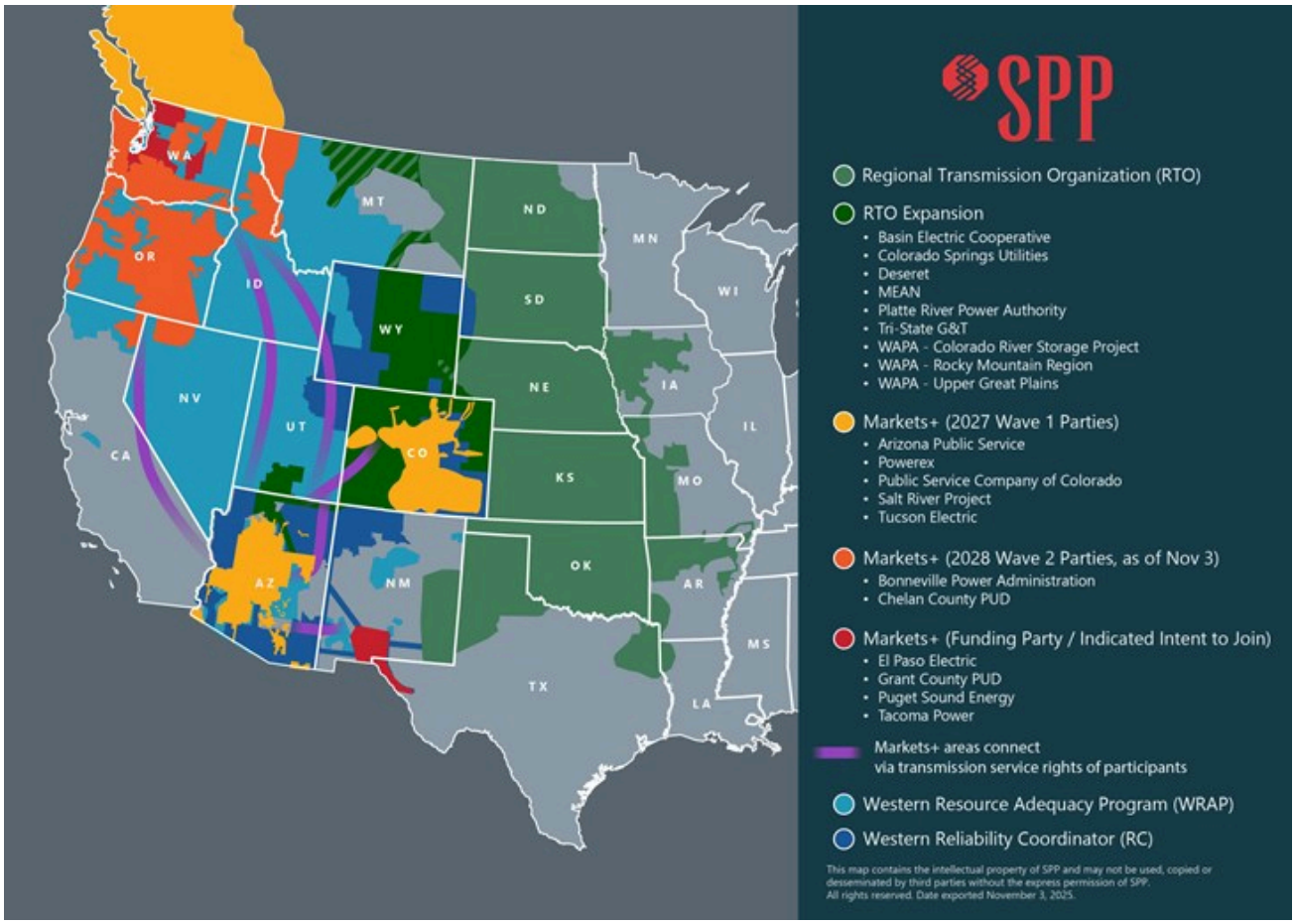
Exhibit 2-167
SPP Markets+ Website

Markets+ - Southwest Power Pool

www.spp.org/marketsplus

MARKETS+

Markets+



Markets+ is more than just a day-ahead market offering. It's a bundle of services that will centralize day-ahead and real-time unit commitment and dispatch and pave the way for the reliable integration of a rapidly growing fleet of renewable generation.

Working together, we've developed a market design that goes beyond current imbalance market service offerings, enhances reliability, increases participant value, equitably compensates participants and incorporates their diverse perspectives.

The Markets+ program has entered Phase Two – Implementation. Potential participants are encouraged to submit an RMS ticket promptly to begin the registration and onboarding process. Indicating intent to participate by the following key registration deadlines is essential to ensure inclusion in the October 2027 go-live:

- Balancing Authorities: September 1, 2025
- Transmission Service Providers: October 1, 2025
- Market Participants: April 1, 2026

Participants seeking to join after October 2027 are still welcome to submit an RMS ticket to express their interest in Markets+.

Markets+ Phase Two Funding Entities:
As of October 27, 2025

- Arizona Public Service
- Bonneville Power Administration
- Chelan County PUD
- Grant County PUD
- Powerex
- Puget Sound Energy
- Salt River Project
- Tacoma Power
- Tri-State G&T
- Tucson Electric Power
- Xcel/Public Service Company of Colorado

For a list of participants, click here.

Quick links:

- **Visit the Markets+ Stakeholder page** for events and materials related to the Markets+ stakeholder groups
- **Markets+ Tariff**

- To receive emails related to Markets+ groups and task forces, subscribe to each group's exploder. For general Markets+ information, subscribe to the SPPMarkets+ Exploder on your **account page. (Learn more about Exploders here.)**
- **Market+ Project Timeline**

Latest Markets+ Phase Two News:

- February 14, 2025 | Markets+ phase two development confirmed with western market commitments
- January 16, 2025 | SPP's Markets+ tariff receives FERC approval
- July 31, 2024 | FERC requests additional information regarding Markets+ tariff filing; SPP coordinating response
- June 5, 2024 | SPP files expanded regional transmission organization tariff to include western entities
- April 15, 2024 | Western utilities express support for continued Markets+ development
- April 1, 2024 | Southwest Power Pool completes and files Markets+ tariff with collaboration and support from western stakeholders

WESTERN SERVICES

- › Western Newsroom
  - Press Releases
  - COVID-19
  - 2021 Winter Storm Review
  - Holistic Integrated Tariff Team
  - Stakeholder Report
- Western Events
  - Calendar
  - Registration
- › Markets+
  - Markets+ Initiative Requests
  - Join Markets+
- › RTO Expansion
  - New Member Integration
  - RTO Expansion Program Documents
  - Southwest Power Pool Current List - RTO Expansion Project 20240412
  - RTO Expansion Revision Requests
- Western Resource Adequacy Program
- › Western RC Services
  - WIT Administration
  - Modification Oversight Process

- Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP)
- › WEIS
    - WEIS Revision Requests

RELATED DOCUMENTS

- Help Guide: Get Involved in Markets+ on SPP.org
- Markets+ Service Offering
- Final Markets+ Tariff - April 18
- Exhibit 1 Phase 2 - 11.10.25
- Markets+ History & Phase One Participants
- Markets+ Protocols Production

RELATED DOCUMENT GROUPS

- Markets+ Documents
- Markets+ Program Materials
- Markets+ Initiative Requests

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-168
Tri-State Extreme Weather Event Modeling Assumptions

Colorado PUC E-Filings System

Extreme Weather Sensitivity

A dispatch sensitivity is modeled to simulate Extreme Weather Event (EWE) impacts and duration, and to evaluate system reliability. The following modeling inputs will be used to simulate EWEs:

Table 1: EWE Modeling Inputs

Assumption Item	Phase I Description	Phase II Description
Load	Gross up the extreme weather week by using the change in temperature and precipitation from actual storm event months compared to 10-year weather normalized load. Apply the monthly increase to the EWE week using the historical EWE weather patterns/shapes from the event, adjusted for known Member departures. Weather and patterns are calculated at the planning region level.	Continued approach of Phase I storm event load stress methodology during the Resource Acquisition Period (RAP), through 2031. For Post-RAP period, starting in 2032, selection of events from applicable EWE Database[1] Tier 2 or 3 events (identified below). The winter stress will continue to utilize the modeling approach used in Phase I. The summer EWE event utilizes the base load forecast, rather than reflecting the Phase I EWE load stress methodology to ensure a reasonable resource stress.
Load Forecast and EWE Period	EWE dates in January and July aligned the date of peak load in the storm shape with the peak load in the base forecast.	EWE dates in January and July will be selected to align the day of week of the storm shape with the day of the week of the load forecast. The EWE dates will be chosen such that the 168-hour EWE events modeled will overlay the date of the forecasted monthly peak for the base load forecast for the Western Interconnect.

[1] In 2024, Tri-State procured a third-party (Astrape) "EWE Study" and database of historical EWE events ("EWE Database") to inform the EWE simulation.

Assumption Item	Phase I Description	Phase II Description
Gas Prices	Winter EWE gas prices range from $5 to $200/MMBtu which reflects Winter Storm Uri (Feb. 11-17, 2021) pricing. Summer EWE gas prices range from $6 to $8/MMBtu which reflects Summer EWE event (July 17-23, 2022) pricing.	No change.
Power Prices	The historical purchase and sales hourly weighted average price of all zones and take the highest hourly price between purchase and sales. For hours with neither a historical purchase nor sale, the highest price between transactions was used. Maximum price during Winter events (Feb. 11-17, 2021) is $800/MWh and the maximum price during summer events (July 17-23, 2022) is $258/MWh.	No change.
TOT 3	Derated to 75% of maximum capacity for all hours of three days in the winter EWE period. Derated to 75% of maximum capacity for hours ending 16-21 during the summer EWE period.	No change.
Wind and Solar Resource – Net Availability	Stressed profiles were created for existing, under contract, bid, and generic resources. • *Winter Stress:* Observed data from Winter Storm Uri, actual generation used for existing units, representative irradiance and wind data used for generic and new generation not yet online. Additional stress of 50% for ECO, 80% for WCO, WYO, and NM for a 72-hour period during days 2-4 of the stressed period. • *Summer Stress:* Observed data from summer 2022 heat wave actual generation used for existing units, representative	2026-2031: • *Winter Stress:* Observed data from Winter Storm Uri, actual generation used for existing units, representative irradiance and wind data used for bid and new generation not yet online. Additional stress of 50% for ECO, 80% for WCO, WYO, and NM for a 72-hour period during days 3-5 to better align with peak during EWE event considering member departures. • *Summer Stress:* No change.

Assumption Item	Phase I Description	Phase II Description
	irradiance and wind data used for generic and new generation not yet online. Additional stress on solar profiles of 50% for ECO, WCO, and NM. Additional stress on wind profiles of 50% for ECO and NM and 80% for WYO for a 72-hour period during days 1-3 of the stressed period.	2032-2043: Stressed profiles were selected from the EWE Database for existing, under contract, bid and generic resources. • *Winter Stress:* Observed data from 1/8/2011-1/14/2011 Tier 3 Extreme Load Event. • *Summer Stress:* Observed data from 7/25/18-7/31/18 Tier 2 Net Load Event.
Dispatchable Resources	• *Winter stress:* Outages and derates for existing thermal coal and gas units will match the 2/11/2021 to 2/17/2021 event. • *Summer stress:* Outages and derates for existing thermal coal and gas units will match the 7/17/2022 to 7/23/2022 event.	2026-2031: No change. 2032-2043: • *Winter stress:* Derates of 9% applied to existing gas units for hours of EWE where system-weighted temperatures are below 0F degrees. • *Summer stress:* Derates of 1% applied to existing gas units for hours of EWE were system-weighted temperatures are above 95F degrees.
Market Depth (Purchases)[2]	Determined hourly purchase volumes for EWEs, at the market area level, based on historical activity; allowing market purchases during limited hours and markets of EWEs as follows: • Winter – NM Market allowed HE2-HE6; HE11-HE15; all other markets are closed for purchases. Hourly market depth of 60 MW.	No change.

[2] Market sales are open in the modeling.

Assumption Item	Phase I Description	Phase II Description
	○ Day 4 of EWE event, no purchase market available • Summer – ECO, WCO, WYO Markets allowed HE2-HE13; NM market closed for purchases. Hourly market depth of 70 MW. ○ Day 1 of EWE event, no purchase market available	

Summary of EWE Stress

Key features of RAP-period EWE Events:

- 168-hr event:
  - Winter EWE based on Storm Uri (Feb. 11-17, 2021).
    - Additional stress on resources 50% for ECO, 80% for WCO, WYO, and NM for a 72-hour period during days 3-5.
  - Summer EWE based on prior event (July 17-23, 2022).
    - Additional stress on solar profiles of 50% for ECO, WCO, and NM; and
    - Additional stress on wind profiles of 50% for ECO and NM and 80% for WYO for a 72-hour period during days 1-3.
- The dates of the storm shape are inclusive of the peak load in the base forecast for both Winter and Summer EWE. Summer peak loads are highest on days 1-3 and 5-6. Day 6 has the highest peak EWE load, but since the three-day period of days 1-3 have higher peak loads than a three-day period including Day 6, the additional renewable stress is on Days 1-3.

Key features of Post-RAP period EWE Events:

- 168-hr event:
  - Winter EWE based on Tier 3 Extreme Load Event (Jan. 8-14, 2011).
  - Summer EWE based on Tier 2 Net Load Event (July 25-31, 2018).
- Aligned the date of the forecasted monthly peak for the base load forecast for the Western Interconnect to fall within the storm shapes for both Winter EWE and Summer EWE.

Stressed Resource and Load Profiles for EWE Sensitivity Analysis

The adjustments made to create simulated EWE "stressed" profiles for existing, under contract, bid and generic resources, load, and transmission are described herein.

The EWEs for each portfolio were assumed to be one week (168 hours) in January and one week (168 hours) in July of each year, from 2026 to 2043.[3] The specific 168 hours were selected to align the day of the week between the forecast calendar and the storm shape, while overlapping with the monthly peak load for the Western Interconnect in the forecast in each modeled storm event.

Level II reliability target checks were performed on each portfolio's EWE sensitivity result, including:

- ≤ 12 loss of load hours combined during all EWEs in 2026-2031 (the resource acquisition period)
- ≤ 3 loss of load hours per year without available capacity
- EUE must be ≤ 20% of load in any hour
- Evaluation of market purchases vs remaining hourly available dispatchable capacity to ensure that EUE was not avoided through the use of market purchases as capacity.

Level II reliability metrics for each portfolio are identified in Attachment E.

Load Stress

To simulate the load stress that may occur during an EWE event, actual monthly energy by planning region for the storm month will be compared to weather normalized load values for the month in which the historical event occurred on the Western Interconnect. The weather normalization model specification includes precipitation and heating- and cooling-degree-days. Monthly increases in energy are derived from these statistical models and the differences are applied to the EWE week using the corresponding historical weather event shape by region and season for each forecasted 168-hour EWE event. In the summer EWE forecasts for the post-RAP period, the load reflects base weather normalized load to ensure the EWE stress is not unreasonably low, below the base load forecast. The historical shapes are adjusted to reflect the expected departures of Members on the Western Interconnect.

The load stress approach for the EWE sensitivity is both reasonable and robust. It is reasonable because it is using actual weather events to estimate load changes and align load and resource shapes. It is robust because it is assumed that differences in the weather models over a one-month period are correlated to extreme weather in the 168-hour period. The methodology utilized is consistent with the EWE load stress modeling approach in 2023 ERP Phase I. For the summer post-RAP period, we retain base, weather normalized shapes to prevent the extreme load stress from being unreasonably low in order to support a reasonable stress.

[3] Tri-State modeled the EWE Sensitivity across 2026-2043, with 2024 having already concluded and being already into 2025, with those years also being outside of the Resource Acquisition Period (RAP).

Gas Prices

Tri-State utilized gas price index data from its Energy Trading and Risk Management system for applicable events to arrive at pricing. See Table 1 above.

Power Prices

Tri-State utilized transactional data from its Energy Trading and Risk Management system for historical EWE events to arrive at stressed power pricing. Actual purchase and sales price data during historical EWE events was analyzed. The weighted average price between the following zones was calculated for each hour: FOURCORNER345, CRG, BOZ, AU, SPRINGER345, SJ345, SGW, DJ, and MIDWAY. These zones represent the four market areas in the EnCompass model: Eastern Colorado (ECO), New Mexico (NM), Western Colorado (WCO), and Wyoming / West Nebraska (WY/WNE). A weighted average was calculated for both purchases and sales. The maximum purchase/sale price was used for the EWE interval price. For hours where there were no transactions, a price based on the higher of the pre- or post- non-transaction hours was used. Each market area has the same market price for the hour to prevent arbitrage between the markets. See Table 1 above.

Transmission Stress

TOT3 is derated to 75% of maximum capacity for all hours of three days in the Winter EWE period. TOT3 is derated to 75% of maximum capacity for hours ending 16-21 for seven days in the Summer EWE period. The winter derate is based on patterns seen during Storm Uri. The summer derate is based on typical unscheduled flow impacts during high load, hot summer days.

Wind and Solar Stress Levels

The wind and solar resource capacity was modified in the EWE periods modeled to represent an assumed change in renewable unit performance anticipated during an extreme weather event across the Tri-State system. The stressed profiles are reflective of unit performance that were the result of the impacts of extreme weather previously observed through the historical data, as well as recognizing the statement made in Commission Decision No. C23-0437 (Proceeding No. 20A-0528E) in Paragraph 57, "…history may not be fully predictive of future weather extremes..." The historical extreme weather events used during the resource acquisition period (RAP) for renewables modeling were Winter Storm Uri in February 11-17, 2021 and a heat wave event that occurred in July 17-23, 2022. During the RAP an additional stress was applied for wind and solar in summer and winter, for a 72-hour period. Post-RAP renewable shapes are applied as defined in the EWE Database for the applicable timeframe defined in Table 1. The renewable stresses reflect system diversity by applying unique assumptions for each planning region.[4]

Wind

Severe weather can have a detrimental impact on wind generation, caused by factors such as low wind, icing, or maintenance issues. To ensure that the wind profiles accurately reflect extreme weather

[4] Wind is not modeled in as a resource in WCO.

conditions on the system, Tri-State utilized actual observed generation and weather conditions as a baseline for the EWE, where available.

RAP Period

For wind generation facilities that were online during the historical extreme weather events, Tri-State used actual metered generation output recorded in its SCADA system. In cases where generation had been contracted but not yet online, and for generic wind units, Tri-State relied on regional weather and wind data to estimate the output from facilities and then applied an additional stress to that output. To obtain the wind data, Tri-State used Visual Crossing data for a representative site in each generation area, and then applied a power curve developed by the National Renewable Energy Laboratory (NREL) based on data from two commercially available onshore IEC Class I machines to convert wind speed data into hourly generation.

Post-RAP Period

Tri-State used applicable profiles as defined in the EWE Database.

Winter

During the RAP, for a 72-hour period within the EWE, the WY/WNE and NM planning regions' wind resource profiles are stressed down by 80% and stressed down by 50% in the ECO planning region, as shown in Attachment E-1. Post- RAP Tri-State used applicable profiles as defined in the EWE database which was observed data from 1/8/2011-1/14/2011 Tier 3 Extreme Load Event.

Summer

During the RAP, for a 72-hour period within the EWE, the WY/WNE planning region wind resource profile is stressed down by 80%; and stressed down by 50% in NM and ECO planning regions, as shown in in Attachment E-1. Post-RAP, Tri-State used applicable profiles as defined in the EWE Database, which was observed data from 7/25/18-7/31/18 Tier 2 Net Load Event.

12Solar

During winter months, solar capacity profiles tend to decrease due to limited daylight, and weather conditions such as prolonged cloud cover can also have an impact.

During the RAP, to illustrate the effect of historical extreme weather on solar generation, Tri-State utilized actual generation data as recorded by SCADA and retained in OSIsoft PI for existing solar units and then applied an additional stress. In cases where generation had been contracted but not yet online, and for generic solar units, Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) irradiance data were used to estimate expected solar generation. Tri-State obtained this solar data from Visual Crossing and the NREL National Solar Radiation Database, and then used the NREL System Advisory Model (SAM) to simulate hourly power generation from photovoltaic (PV) arrays. Representative sites were selected from each planning region for this analysis. Post-RAP, Tri-State used applicable profiles as defined in the EWE Database.

Winter

During the RAP, WCO and NM planning regions' solar resource profiles are stressed down by 80% and stressed down by 50% in ECO planning region. Post-RAP, Tri-State used applicable profiles as defined in the EWE Database, which was observed data from 1/8/2011-1/14/2011 Tier 3 Extreme Load Event.

Summer

During the RAP, for a 72-hour period within the EWE, WCO NM and ECO planning regions' solar resource profiles are stressed down by 50%. Post-RAP, Tri-State used applicable profiles as defined in the EWE Database, which was observed data from 7/25/18-7/31/18 Tier 2 Net Load Event.

Dispatchable Resources

During the RAP, outages and derates for existing thermal coal and gas units reflect the 2/11/2021-2/17/2021 event for the Winter EWE. Outages and derates for existing thermal coal and gas units reflect the 7/17/2022-7/23/2022 event for the Summer EWE. Post-RAP, Winter EWE reflects derates of 9% applied to existing gas units for hours of EWE where system-weighted temperatures are below 0F degrees; and Summer EWE reflects derates of 1% applied to existing gas units for hours of EWE were system-weighted temperatures are above 95F degrees.

Market Depth Purchases

Tri-State reviewed transactional activity system for applicable events in its Energy Trading and Risk Management to determine likely hours with availability of market power for purchasing by planning region and related market depths. See Table 1 above.

While Day 6 of the EWE is the peak load day in the summer, no market purchases are on Day 1 of the EWE. Day 4 is the peak load day in the winter; therefore, Tri-State assumed that during the height of the EWE that no market purchases would be possible due to operational constraints likely occurring for all utilities in the region.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
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PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-169
Colorado PUC Press Release, Feb. 18, 2026

Select Language

COLORADO

Department of Regulatory Agencies (/)

Public Utilities Commission

Home (/) Colorado Public Utilities Commission Approves New Energy Resources for Xcel Energy

Colorado Public Utilities Commission Approves New Energy Resources for Xcel Energy

February 18, 2026 - The Colorado Public Utilities Commission (PUC) today approved up to 4,100MW of new energy generation for Xcel Energy. The ten projects approved include a mix of solar, storage, wind, and natural gas. A final, written decision will be issued in the coming weeks.

These projects were approved as part of a stand-alone expedited process, termed the Near Term Procurement or NTP, Proceeding No. 21A-0141E, which was established to take advantage of expiring federal tax credits. In 2025, Congress passed H.R. 1 Act which set new, earlier expiration dates for renewable energy projects.

“Today’s action locks in cost savings for Xcel customers as we work to replace aging coal plants and meet growing energy demand,” said Rebecca White, Director of the Public Utilities Commission. “This was an extraordinary effort on the part of multiple stakeholders to bring these projects forward quickly in order to leverage expiring tax credits and save ratepayers billions. The Commission, in turn, closely reviewed these projects on a very tight timeline to ensure the best mix possible for ratepayers.”

In September of 2025, the Utility Consumer Advocate, Colorado Energy Office and Public Utility Commission staff joined Xcel Energy in proposing projects for accelerated review by the Commission. Today’s approval moves 3,200 MW in projects immediately forward with a potential of an additional 600-900 MW. Three of the projects approved today will be located in “just transition” communities impacted by the planned closure of coal-fired power plants.

The Commission’s approval is part of a broader effort across State Government to streamline and accelerate the development of eligible clean energy projects to provide reliable, affordable energy.

More information on Proceeding No. 21A-0141E can be found in E-Filings (https://www.dora.state.co.us/pls/efi/EFI.homepage).

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-170
Colorado PUC Feb. 2026 Decision

Decision No. C26-0117

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0141E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN.

COMMISSION DECISION ADDRESSING APPLICATIONS FOR REHEARING, REARGUMENT, OR RECONSIDERATION OF COMMISSION DECISION NO. C26-0081

Issued Date: February 23, 2026
Adopted Date: February 18, 2026

TABLE OF CONTENTS

I. BY THE COMMISSION 2
A. Statement 2
B. Procedural History 2
C. RRRs 4
1. State Agencies 4
2. Interwest 5
3. CIEA 6
4. Public Service 7
D. Findings and Conclusions 9
II. ORDER 14
A. The Commission Orders That: 14
B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING February 18, 2026. 15

Colorado PUC E-Filings System

I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission addresses the Application for Rehearing, Reargument, or Reconsideration ("RRR") of Decision No. C26-0081 that Trial Staff of the Commission, the Colorado Energy Office, and the Colorado Office of the Utility Consumer Advocate (collectively the "State Agencies") jointly filed on February 9, 2026, as well as the RRRs filed on February 13, 2026, by Public Service Company of Colorado ("Public Service" or the "Company"), Interwest Energy Alliance ("Interwest"), and Colorado Independent Energy Association ("CIEA").

B. Procedural History

2. On August 22, 2025, the State Agencies and the Company filed a Joint Motion to Initiate a Near-Term Procurement ("Motion to Initiate NTP").

3. Through Decision No. C25-0652-I, issued September 8, 2025, the Commission granted, with modifications, the Motion to Initiate NTP.

4. Public Service filed its NTP Motion and the accompanying NTP Report on December 5, 2025.

5. The Commission held the technical conference on December 18 and 19, 2025.

6. On January 12, 2026, several parties filed timely responses or comments to the NTP Motion and NTP Report.

7. Public Service filed its Unopposed Motion for Leave to File Reply Comments and Reply Comments on January 23, 2026.

8. The Commission deliberated on this matter at the January 28, 2026 Commissioners' Weekly Meeting ("CWM").

9. In response to the Commissioners' deliberations at the January 28 CWM, but prior to issuance of the Commission's written decision, the State Agencies and Interwest filed an Emergency Motion Requesting Decision Approving Near-Term Procurement Resources ("Emergency Motion") on February 3, 2026. At a high level, the Emergency Motion asked the Commission to change the outcome of its oral deliberations and approve either the State Agencies' proposed NTP portfolio or the Company's proposed NTP portfolio.

10. The Colorado Solar and Storage Association and Solar Energy Industries Association ("COSSA/SEIA"), the Natural Resources Defense Council and Sierra Club (collectively, "Conservation Coalition"), and Public Service, respectively, filed responses in support of the Emergency Motion on February 3, 2026.

11. Through Decision No. C26-0081, issued February 5, 2026, the Commission granted, in part, and denied, in part, the Motion to Acquire NTP Resources ("NTP Decision").

12. The State Agencies jointly filed a RRR of Decision No. C26-0081 on February 9, 2026.

13. Through Decision No. C26-0095, issued February 11, 2026, the Commission denied the Emergency Motion as untimely and procedurally inappropriate.

14. In our NTP Decision, as it relates to the projects included within the approved NTP portfolio of resources, the Commission approved the following for immediate contracting and procurement: Bid 053, Bid 054, Bid 034, Bid 135, Bid 099, and Bid 113. However, the Commission deferred selecting among Bid 046, Bid 055, Bid 094, Bid 089, Bid 003, Bid 118, and Bid 056 for inclusion in the approved NTP portfolio until after Public Service provides additional clarity regarding the business case for moving forward with these various projects. The Commission set a deadline of March 2, 2026, for Public Service to provide this additional

analysis, which includes a 10-year forecast when the key Denver Metro substations comprising the

Denver Metro transmission constraint are projected to be fully loaded. In addition, the Commission conditioned approval of Bid 127 until after the Company filed updated Encompass modeling on April 2, 2026.[1]

15. On February 13, 2026, Public Service, Interwest, and CIEA each filed a RRR to the NTP Decision.

C. RRRs

1. State Agencies

16. In the State Agencies' RRR, they ask the Commission to reconsider the NTP Decision to require additional new analysis and instead approve a final resource portfolio at the Commissioner's February 11, 2026 CWM. They argue that each passing day without a final decision increases the risk that projects will not be able to qualify for the federal tax credits.

17. The State Agencies further argue the NTP Decision creates an unnecessary new process that was not contemplated by the Motion to Initiate the NTP. They cite the Commission decision approving, in part, the Motion to Initiate NTP and argue that if the Company had known in advance that the Commission desired to see a spreadsheet analysis of the benefits of locating bids inside versus outside the Denver Metro Area, it could have provided this analysis as part of its NTP Report. Because the Commission did not request this analysis in advance, the State Agencies assert the Commission should reconsider how its belated request will cause timeline delays and ultimately risk the procurement of tax-advantaged projects.[2]

[1] Decision No. C26-0081 at ¶ 80.
[2] State Agencies RRR at p. 11.

18. The State Agencies similarly argue the Commission's directives regarding Bid 127 are contrary to the Motion to Initiate the NTP, which contemplates that Public Service will not conduct additional EnCompass modeling given the timing. They also argue the Commission failed to establish what criteria it would use to determine if the results of the EnCompass modeling warrant approving Bid 127.

19. As for the requested spreadsheet analysis, the State Agencies warn the Company may be unable to provide the requested analysis on hourly transmission constraints without additional modeling. The State Agencies note that such transmission modeling was not provided in Proceeding No. 24A-0560E, which evaluated a proposed transmission investment to help address the Denver Metro constraint.[3]

20. Regardless, the Stage Agencies argue that even if the Company is able to timely provide the requested analysis, it will still take time for the Commission to analyze the results, make decisions, and process any subsequent RRR that may arise. They argue that each delay makes it more difficult for developers to qualify for tax credits.

21. The State Agencies ultimately recommend the Commission unconditionally approve the State Agencies' NTP portfolio or the Company's Tier 1 portfolio. The State Agencies only recommend additional analysis if the Commission first approves the State Agencies' preferred portfolio but also wants to enlarge the portfolio with additional projects.[4]

2. Interwest

22. Like the State Agencies, Interwest requests that the Commission expeditiously approve as large of an NTP portfolio as possible, which could include the remaining projects in

[3] State Agencies RRR at p. 12.
[4] State Agencies RRR at pp. 16-17.

either the State Agencies' or the Company's NTP portfolio. According to Interwest, there is no evidence that the Commission's requested analysis exists or can be created, and on what timeline. Interwest argues that the uncertainty at this late stage is sending the exact opposite signal to the market that the NTP was designed to send and that developers will prioritize projects wherever certainty exists.

23. Interwest warns that that "billions of dollars" of expiring tax credits are at stake, and the Commission risks losing out on the benefit of the tax credits and spending more on the same or similar projects in future solicitations.[5] Interwest adds that the analysis of which projects can reliable retire the coal plants is better suited for the Just Transition Solicitation ("JTS") procurement in Proceeding No. 24A-0442E, as the NTP is designed to maximize cost effective, tax credit eligible resources in a one-time opportunity that is quickly expiring.

3. CIEA

24. CIEA likewise argues the Commission should quickly approve Public Service's full Tier 1 portfolio. Among other points, CIEA argues it is far from certain that the additional analysis thee Commission requested will even be available or accurate on such an expedited timeline. CIEA adds that the rushed timeframe of the additional analysis will likely not allow for party feedback. According to CIEA, "if the Commission allows locational factors such as the Denver Metro Constraint to be analyzed in the NTP, it cannot do so without allowing scrutiny of the Company's analytical methods given that the Company has now seen the available bids, and heard them discussed by the Commissioners."[6] CIEA adds the NTP was not initiated for the sole purpose of grid optimization, it was also aimed at a just transition and that the Commission should

[5] Interwest RRR at p. 3.
[6] CIEA RRR at p. 10.

not disregard siting projects in just transition communities in favor of projects within the Denver Metro constraint.[7]

25. More generally, CIEA argues that a prolonged proceeding risks the underlying goal of quickly acquiring clean energy resources. CIEA reiterates how this goal was set forth in the Motion to Initiate the NTP that Public Service and the State Agencies initially filed as well as the August 1, 2025 letter from Governor Polis.[8] CIEA argues that with additional delays, developers may repurpose safe-harbored equipment to other states. The possibility of losing the expiring tax credits outweighs the benefits of attempting further optimization. CIEA adds that it "reserves its right to file subsequent [RRR] seeking relief associated with project delays if the Commission's decision approving a final portfolio is issued significantly later than the date expected by [developers] when formulating bids and tax credit qualification strategies."[9]

26. CIEA avers that one of its members has reported that for at least two projects being actively considered by the Commission, the levelized energy cost that could be offered for the same projects in the JTS would immediately increase by more than 50 percent if the projects lose eligibility for tax credits.[10]

4. Public Service

27. In its RRR, Public Service states that it continues to support the full Tier 1 NTP portfolio. The Company asserts the resources included in the Tier 1 portfolio are necessary to serve load under any forecast if the Company is to continue to make progress reducing overall emissions consistent with State policy.[11] The Company notes broad support for the full NTP portfolio and

[7] CIEA RRR at pp. 9-10.
[8] CIEA RRR at p. 3.
[9] CIEA RRR at p. 6.
[10] CIEA RRR at p. 8.
[11] Public Service RRR at p. 2.

states the independent power producer trade associations and environmental advocates "recognize the need for action now to avoid unnecessary project price increases and to secure tax benefits for customers before they expire."[12] According to Public Service: "If the State, the Company and our customers are going to seize upon huge tax benefits, the Commission must act under some uncertainties and without perfect information, just as in any other business environment."[13]

28. Public Service raises concerns with the delayed approval of certain resources, warning that any delay will likely increase costs, compromise commercial operation dates ("CODs"), and threaten project viability. The Company asserts that just because some projects may be able to safe harbor does not mean that they will remain available in a later solicitation, much less at the same price. On this point, the Company provides confidential bidder feedback indicating that certain renewable resources that were not included in the approved NTP portfolio will likely be more expensive in the future, delayed, and potentially unavailable.[14]

29. Regarding the Commission's stated transmission concerns, Public Service asserts that "there will be no way to solution the combined NTP/JTS Base portfolio to eliminate significant transmission infrastructure additions and improvements."[15] The Company references the JTS Direct and Rebuttal Testimony and NTP Reply comments for the point that additional transmission investments will be needed under all scenarios to continue integrating renewables onto the system to meet the 2030 statutory goal and beyond.

30. In addition to its concerns regarding the NTP portfolio, Public Service seeks clarification of the Commission's directive for additional analysis by March 2, 2026.

[12] Public Service RRR at p. 3.
[13] Public Service RRR at p. 5.
[14] Public Service RRR at p. 4.
[15] Public Service RRR at p. 3.

The Company states it will provide the requested spreadsheet analysis incorporating the $191/kW transmission constraint credit as soon as possible and will use such analysis to inform the business case analysis the Commission has requested. However, the Company asserts it cannot provide the 10-year forecast of the Denver Metro constraint because this "is not an off-the-shelf product."[16] The Company estimates that providing the 10-year transmission forecast the Commission requested "would require significantly more time - likely several months of detailed planning and analysis to complete." [17]

31. Nevertheless, the Company states it will provide the information it can by March 2, 2026, to help inform the Commission's conversation and that it is also analyzing other constraints, such as the constraint impacting the transmission corridor known as total of transmission ("TOT") 5. Public Service requests clarification that its plan for the March 2, 2026 filing is acceptable.

D. Findings and Conclusions

32. We grant, with modifications, in part, and deny, in part, the RRRs set forth above. We reiterate the difficulties of making such large investment decisions without better analysis regarding things like transmission investments, curtailments, and the optimal mix of resources. However, the arguments put forth in RRR have convinced us to move forward now with certain additional resource procurements. While we are disappointed the Company is unable to quickly provide the 10-year forecast of the Denver Metro constraint, we nevertheless appreciate the parties filing the RRRs as quickly as they did. The Commission is working to flexibly balance the need

[16] Public Service RRR at p. 6.
[17] Public Service RRR at p. 6.

for quick regulatory processes with the reality that these are complex decisions regarding large investments.

33. Specifically, we now include Bid 089 (a 500 MW power purchase agreement ("PPA") solar),[18] Bid 046 (a 400 MW PPA solar plus storage), and Bid 055 (a 200 MW PPA solar plus storage) within the approved NTP portfolio. All three of these projects are included within both the State Agencies' recommended portfolio as well as the Company's recommended portfolio. While we will continue to try to optimize the selection of generation resources in ways that can potentially reduce other system costs such as additional transmission investments and curtailments, we find it unlikely that these three projects will not be valuable to the system. Given the need for significant amounts of new generation, the favorable pricing of these projects, and the likelihood that their costs will increase in the near future, we find it appropriate to immediately include these projects in the approved portfolio.

34. At the same time, we defer including Bid 127 (a 608 MW Company-owned wind project) in the approved NTP portfolio until we are better able to compare it to Bid 094 (a 450 MW Company-owned solar plus storage project). While Bid 127 is included within the State Agencies' and the Company's recommended portfolios, we question whether this large wind project should be replaced with Bid 094, a large solar plus storage project. Bid 094 is included in the Company's Tier 2 backup portfolio, has a higher accredited capacity than Bid 127,[19] and is located within the Denver Metro constraint. Although Bid 127 has a lower scoring levelized cost

[18] While voting to unconditionally approve Bid 089, Chair Blank's first preference would be to conditionally approve Bid 094 instead, which would provide 450 MW of solar and 450 MW of storage within the Denver Metro constraint. Chair Blank is concerned about the Company's ability to rely on Bid 089 during periods of peak load because the 500 MW solar project is located outside of the Denver Metro constraint.

[19] *See* State Agencies' Response to NTP Motion, Attachment JPSA-1.

than Bid 094, the Company has indicated that without Encompass modeling it is difficult to compare the levelized cost of solar plus storage projects with other types of technologies.[20] Replacing Bid 127 with Bid 094 may also be warranted based on the pricing shifts experienced for wind projects as opposed to solar and storage projects. Similar to arguments the State Agencies make regarding excluding the four highest-cost wind projects from the NTP portfolio, computer-based modeling might show that a 450 MW solar plus storage resource is more valuable than a 608 MW wind resource.[21]

35. In addition, we remain concerned that the selection of Bid 127 does not account for the additional transmission investments that will be necessary to deliver the power into the Denver Metro constraint. While we acknowledge the Company's assertion that more transmission investment is likely necessary under any scenario, Bid 094's location within the Denver Metro constraint could reduce those transmission costs. After factoring in the $191/MW Denver Metro transmission credit, Bid 127 may be a higher cost than Bid 094.

36. In the upcoming March 2, 2026 analysis, Public Service will provide, among other things, a spreadsheet analysis incorporating the Denver Metro transmission constraint credit into the Scoring Levelized Energy Cost metric. This is the type of additional analysis that will better allow us to decide which project to include in the approved NTP portfolio. After we receive this analysis, the Commission will decide whether to select Bid 094, Bid 127, or whether to wait until the Commission has the April 2, 2026 EnCompass modeling.

37. As for Bid 118 (a 400 MW PPA storage project), the Company's arguments regarding transmission concerns do not persuade us to remove Bid 118 from the approved

[20] NTP Report at p. 40.
[21] *See* Decision No. C26-0081 at ¶¶ 65-67.

portfolio.[22] The NTP Report has several examples of bids being excluded from the Tier 1 and Tier 2 portfolios because of transmission concerns.[23] Moreover, the Company clarified in its Reply comments that it marked bids as "Failed" either when a project had insurmountable flaws for the NTP (like transmission development/interconnection risk) or for projects that would be better suited to the JTS Request for Proposals.[24] None of these concerns are set forth in the NTP Report for Bid 118. Rather, Public Service includes Bid 118 in its Tier 2 portfolio for which it sought Commission approval.

38. Public Service first discussed transmission concerns regarding Bid 118 at the technical conference. In addition to the transmission concerns regarding TOT 5, Company witness Mr. Landrum stated the storage project would use scarce interconnection capacity in that area and that it would be better to wait until the JTS when there is more competitive tension for those interconnection resources.[25] Given the NTP was an open source solicitation, we find the Company's arguments to wait for more competitive tension to be confusing.

39. In its Reply comments, Public Service provides more detail with respect to its transmission concerns regarding Bid 118, including statements it marks as highly confidential regarding its transfer rights in TOT 5.[26] These new details are again confusing given that Public Service will have the ability to choose when and how to charge and discharge Bid 118.

[22] The State Agencies include Bid 118 in their recommended portfolio. While the State Agencies position Bid 113 (a 300 MW PPA storage project) as an alternate to Bid 118, both projects have attractive pricing and locations (Bid 118 is located in a just transition community, and Bid 113 is located within the Denver Meto constraint). Given these positive attributes and the fact that our approved NTP portfolio has fewer wind resources than the Company's Tier 1 portfolio, we find it appropriate to include both Bid 113 and Bid 118 in the approved portfolio.

[23] *See, e.g.*, NTP Report at p. 51.

[24] Public Service Reply comments at p. 14.

[25] Hr. Tr. December 18, 2025, pp. 103-04.

[26] Public Service Reply comments at p. 18.

Moreover, Public Service's Reply statements appear to contradict the Company's written testimony in the JTS.[27]

40. While we are unpersuaded to defer Bid 118 until Phase II of the JTS, we do not ignore Public Service's concerns. Bid 118 is included in the approved portfolio subject to the additional transmission analysis the Company argues is necessary.[28] If, after additional analysis, the Company cannot move forward with the project, it can make an appropriate filing explaining its determination. Fortunately, given Bid 118's relatively early COD and low price, there is headroom for COD and price flexibility to allow the Company more time to analyze the transmission impacts. Public Service shall account for this flexibility during PPA negotiations with the developer of Bid 118. Finally, we encourage the Company to also provide the estimated property tax contributions from Bid 118, as such property taxes will be a material benefit to both the Routt County communities and Public Service ratepayers.

41. As for the Company's requested clarification regarding the additional analysis it must provide by March 2, 2026, we affirm the Company's plan as set forth in its RRR is acceptable, including the fact that it will not be able to provide the 10-year transmission forecast of the Denver Metro constraint. Given our RRR rulings set forth in this Decision, however, we further clarify that the March 2, 2026 analysis is only required for Bid 094, Bid 127, and Bid 118.[29]

42. In the NTP Decision, we asked Public Service include Bid 056 (a 200 MW PPA storage project) in the March 2, 2026 analysis. Bid 056 is intriguing given it is one of only a few

[27] Hr. Ex. 101, Attachment JWI-2, Volume 2, pp. 106-07 in Proceeding No. 24A-0442E.

[28] While voting to include Bid 118 in the approved NTP portfolio, similar to Bid 089 Chair Blank's first preference would have been to include Bid 118 as a backup and focus on Bid 094, which is located within the Denver Metro constraint.

[29] We recognize that Public Service may not be able to complete all of the required transmission analysis for Bid 118 by March 2, 2026, but look forward to whatever additional information the Company can provide consistent with its indications in RRR. (Public Service RRR at p. 7).

eight-hour storage projects as well as its price relative to gas units. Given our other RRR rulings and the fact that Bid 056 has not undergone the same due diligence review as other available options, however, we no longer are considering including Bid 056 in the approved NTP portfolio. Nevertheless, we remain intrigued about the apparent benefits of eight-hour storage projects, which have high effective load carrying capability values. In the 120-Day Report that will be filed in Phase II of the JTS, we encourage Public Service to discuss how eight-hour storage projects are comparable to thermal projects.

43. In conclusion, through this Decision we add Bid 089, Bid 046, and Bid 055 to the approved NTP portfolio. We include Bid 118 in the approved NTP portfolio subject to the additional transmission analysis the Company argues is necessary. After Public Service provides additional analysis, we may also include Bid 127 or Bid 094 in the approved NTP portfolio. When accounting for the projects included via Decision No. C26-0095, the approved NTP portfolio consists of the following bids: Bid 089, Bid 046, Bid 055, Bid 118, Bid 053, Bid 054, Bid 034, Bid 135, Bid 099, and Bid 113. The Company should immediately begin contracting and procurement associated with these projects. The Commission will determine whether to also include Bid 127 or Bid 094 in the approved NTP portfolio in a subsequent decision.

II. ORDER

A. The Commission Orders That:

1. The Application for Rehearing, Reargument, or Reconsideration ("RRR") of Decision No. C26-0081 that Trial Staff of the Commission, the Colorado Energy Office, and the Colorado Office of the Utility Consumer Advocate jointly filed on February 9, 2026, is granted, in part, with modifications, and denied, in part, consistent with the discussion above.

2. The RRR that Public Service Company of Colorado filed on February 13, 2026, is granted, in part, with modifications, and denied, in part, consistent with the discussion above.

3. The RRR that Interwest Energy Alliance filed on February 13, 2026, is granted, in part, with modifications, and denied, in part, consistent with the discussion above.

4. The RRR that the Colorado Independent Energy Association filed on February 13, 2026, is granted, in part, with modifications, and denied, in part, consistent with the discussion above.

5. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

6. This Decision is effective immediately upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING February 18, 2026.

(S E A L)

THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

ATTEST: A TRUE COPY

Rebecca E. White,
Director

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-171
Colorado PUC March 31, 2026 Decision

Decision No. C26-0200

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24A-0442E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2024 JUST TRANSITION SOLICITATION.

COMMISSION DECISION ADDRESSING APPLICATION FOR REHEARING, REARGUMENT, OR RECONSIDERATION OF COMMISSION DECISION NO. C26-0121

Issued Date: March 31, 2026
Adopted Date: March 25, 20226

Colorado PUC E-Filings System

I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission addresses the Application for Rehearing, Reargument, or Reconsideration ("RRR") of Decision No. C26-0121 filed on March 16, 2026, by Public Service Company of Colorado ("Public Service" or the "Company"). Consistent with the discussion below, we grant, in part, the Company's RRR.

B. Background

2. We have previously detailed the background and procedural history of this case in Decision No. C25-0747, issued November 6, 2025 (the "Phase I Decision") and Decision No. C26-0121, issued February 24, 2026 (the "First RRR Decision"). Here, we provide only the background necessary for this Decision addressing Public Service's RRR of the First RRR Decision.

3. On November 26, 2025, Public Service, the East Metro Area Business Coalition ("EMABC"), the Coalition for Community Solar Access ("CCSA"), and several other parties filed RRR regarding the Commission's Phase I Decision. Among other topics, these RRRs sought reconsideration on the Commission's directives regarding the inclusion of new large load customers in the load forecast, updated Phase I modeling, and the calculation of the Denver Metro transmission credit.

4. In the First RRR Decision, the Commission denied as premature the RRR proposal from Public Service and EMABC to pursue a "TG Window" approach for new large loads. Under their proposed RRR TG Window concept, Public Service could contract with large load customers by signing updated electric service agreements ("ESA") and interconnection agreements ("IA") without the fair notice provision.

5. We denied this RRR request as premature, citing cost and risk allocation issues. The Commission found that, "until the adjudication of the large load and clean transition tariffs, there is considerable risk that new large loads will impose additional costs on the grid that necessitate changes in rates."[1] In addition, the Commission set forth three directives for the upcoming large load tariff filing. First, the Commission directed the Company to include in its direct case "an alternative that assumes that these new large loads constitute a separate, unique rate class responsible for the costs they impose on the system in addition to any proposal that the Company may choose to submit."[2]

6. Second, in paragraphs 43 and 44 of the First RRR Decision, we ordered the Company to present in the large load tariff "an evaluation of the costs of the proposed large load

[1] First RRR Decision at ¶ 47.
[2] First RRR Decision at ¶ 42.

tariff assuming that the large new loads required a new [combustion turbine ("CT")] plus a reserve margin to be built as calculated based on the most recent gas CT bid prices received."[3] The Commission reasoned the simplest and most transparent way of quickly estimating the incremental system costs that new large loads impose is likely to assume that the capacity requirements of these customers are met by new CTs plus a planning reserve margin.

7. Third, the Commission directed Public Service to include an alternative structure that would reward new large load customers who locate outside the Denver Metro area or flexibly reduce their demand during critical system peak hours.[4]

8. In the First RRR Decision, the Commission also issued directives regarding the Denver Metro transmission credit. In its direct case, Public Service proposed a $191/kW modeling credit for resources interconnecting to the transmission system within the Denver Metro constraint. In the Phase I Decision, we largely approved of this transmission credit but directed the Company to perform additional comparative transmission modeling to fix certain deficiencies in the calculation of the credit.[5]

9. In the First RRR Decision, the Commission agreed with CCSA's contention about an error in the calculation of the Denver Metro transmission credit. The Company had calculated the $191/kW modeling credit by evaluating the change in modeled transmission costs between two fictional but plausible portfolios of generic resources—one with only 150 MW of distributed energy resources ("DERs") and one with 900 MW of DERs. The difference in costs between these two portfolios was divided by the difference in DER MW to arrive at the $191/kW modeling credit. CCSA's RRR argument, which we found convincing, was that 15 percent of the DER in the

[3] First RRR Decision at ¶ 42.
[4] First RRR Decision at ¶ 45.
[5] Phase I Decision at ¶ 366.

Company's modeling was located outside of the constraint, so the denominator in the credit calculation should be only 85 percent of the incremental DER that was actually modeled as being located within the constraint. We granted CCSA's RRR but also agreed with the Company's concern about false precision in the calculation.[6]

10. Separately in the First RRR Decision, the Commission granted, in part, the Company's RRR request to extend the time to submit updated Phase I modeling. At the same time, the Commission refined the requirements for the updated Phase I modeling, including by requiring Public Service to incorporate the $191/kW Denver Metro transmission credit into the modeling. The Commission directed Public Service to file the updated Phase I by April 2, 2026.

C. Discussion

1. Large Load Tariff Filing Requirements

a. Public Service's RRR

11. In its RRR, Public Service now seeks reconsideration of the Commission's requirement to present in the large load tariff filing an evaluation of the costs of serving new large loads based on the price of new CTs. Public Service first argues that attempting to "tag" new generation units and allocate all associated costs to a particular rate class is inconsistent with how the Company runs its system, the State's emissions reduction goals, and accepted methods of cost allocation. Public Service argues that customers draw power from the grid as a whole, and thus the Company does not attempt to assign the costs of particular generation units. According to Public Service, "[t]he Commission has long approved this approach, which is the standard for

[6] First RRR Decision at ¶ 142.

utility rate setting nationwide."[7] The Company adds it has serious concerns about the workability and legality of a rate design that assigns the costs of particular generation units.

12. Second, Public Service argues the Commission's directive to assume that new large loads will be served exclusively by new CTs is contrary to State, Company, and customer emissions reduction goals. Public Service acknowledges new gas units will be needed to reliably serve increasing load but asserts that assuming the large load customers will be served exclusively by CTs is contrary to the emissions reduction goals. Public Service asserts that assigning only CTs to the large load class, instead of a diverse resource mix from the entire system, would inherently be less efficient, sustainable, and cost effective. Instead, the Company argues large loads should be served holistically as part of the Company's overall system needs. Public Service asserts that this is the approach currently used by the Company's sister operating companies within Xcel Energy.[8]

13. Finally, Public Service states there is insufficient time to conduct the additional modeling before the April 2, 2026 filing deadline for the large load tariff proceeding. The Company asserts it has already developed its modeling for the large load tariff based on the Phase I decision, reflecting the traditional approach to building generation portfolios. Public Service asserts that updating its transmission modeling or re-optimizing the modeling of generation portfolios to reflect a CT-only approach would take "at minimum several additional weeks" and further delay the large load tariff filing.[9]

[7] Public Service Second RRR at p. 2.
[8] Public Service Second RRR at p. 3.
[9] Public Service Second RRR at p. 3.

b. Findings and Conclusions

14. We grant, in part, Public Service's RRR on this point. At the outset, we are confused by the Company's statements that the additional analysis will require transmission modeling or re-optimized modeling of generation portfolios. Our directive was for Public Service to present an evaluation of the costs of serving new large loads based on the assumption that the capacity costs are $25/kw-month, consistent with the actual costs of new CTs in the Near-Term Procurement in Proceeding No. 21A-0141E.[10] It is unclear how this analysis requires additional transmission modeling or re-optimization of generation portfolios. Regardless, given the impending April 2, 2026 deadline for the large load tariff,[11] we waive the First RRR Decision's requirement to include this additional analysis as part of the Company's direct testimony. That said, we stop short of eliminating this requirement entirely. This analysis will be submitted at some point in the large load tariff proceeding. In its direct testimony filed in the large load tariff proceeding, Public Service shall specify when it will be able to provide this analysis, which shall be no later than the typical time period for supplemental direct testimony.

15. In addition to the timing issues, Public Service asserts that allocating the costs of particular generation units to a single rate class is inappropriate and that assuming large loads will be served exclusively by CTs contravenes emissions reduction goals. Resolution of such arguments will take place in the actual large load tariff proceeding. For purposes of this JTS Proceeding, however, we stand by our findings that allowing new large loads onto the system under the current rate structure may result in existing customers unfairly subsidizing the higher

[10] First RRR Decision at ¶ 43.

[11] Through Decision No. C26-0155 issued in Proceeding No. 26V-0048E (March 11, 2026), the Commission granted Public Service's request for variance from Paragraph 81 of the Phase I Decision and extended the deadline for the Company to file the large load tariff from January 31, 2026, to April 2, 2026.

costs of serving these large loads. The Company has not shown that its large load proposals are in the public interest.

2. Calculation of the Denver Metro Transmission Credit

a. Public Service's RRR

16. In its RRR, Public Service also asks the Commission to allow the Company to use the unrevised calculation of the Denver Metro transmission credit in its updated Phase I Modeling.[12] The Company states that this modeling was already underway following the original Phase I Decision and that the Company does not have sufficient time to redo the transmission modeling by the April 2, 2026 deadline for the updated Phase I modeling.

17. Public Service notes that it does not contest the reasoning for changing the Denver Metro transmission credit calculation and that the Company will apply the revised modeling credit in Phase II of this Proceeding.

b. Findings and Conclusions

18. We grant the Company's RRR on this issue. Given the Company's representation that there is insufficient time to redo the updated Phase I modeling to incorporate the changes in the Denver Metro transmission credit that we directed in our RRR Decision, using the unrevised calculation is appropriate. As Public Service notes, the revised calculation will be used for purposes of Phase II modeling.

[12] Public Service Second RRR at p. 4.

II. ORDER

A. The Commission Orders That:

1. The Application for Rehearing, Reargument, or Reconsideration of Decision No. C26-0121 that Public Service Company of Colorado filed on March 16, 2026, is granted, in part, consistent with the above discussion.

2. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

3. This Decision is effective upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING March 25, 2026.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-172
Tri-State 2026 Annual Resource Adequacy Report

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

2026 ELECTRIC RESOURCE ADEQUACY ANNUAL REPORTS	)))))	**PROCEEDING NO. 26M-0028E**

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.'S NOTICE OF 2026 RESOURCE ADEQUACY ANNUAL REPORT

Tri-State Generation and Transmission Association, Inc. ("Tri-State"), pursuant to §40-43-104(1)(a), C.R.S., respectfully submits this Notice of 2026 Resource Adequacy ("RA") Annual Report informational filing.

I. BACKGROUND

On or before April 1, 2026, Tri-State, as a load serving entity ("LSE"), is required under §40-43-104(1)(a), C.R.S., to provide the Colorado Public Utilities Commission ("Commission") a RA Annual Report identifying the generating resources and accredited capacity used to serve its Utility Members.[1] On January 1, 2026, the Commission opened Proceeding No. 26M-0028E to receive these reports.

II. TRI-STATE'S 2026 RA REPORT

Tri-State has complied with this requirement with Figure 1 and Table 1.[2] Tri-State's 2025 RA Annual Report has also been made available on Tri-State's website, here: https://tristate.coop/resource-planning.[3]

[1] The Colorado Resource Adequacy Act of 2023 became effective August 7, 2023 (House Bill 23-1039).
[2] Colorado Energy Office ("CEO") has requested that entities subject to §40-43-104, C.R.S. also complete a "Resource Adequacy Spreadsheet" to be returned to CEO by April 30, 2026. Tri-State intends to voluntarily respond to this request.
[3] On January 11, 2025, Tri-State received guidance from CEO (pursuant to §40-43-104(3), C.R.S.) requiring each LSE to make its RA annual report available on its website and searchable by including "Resource_Adequacy_2026."

Colorado PUC E-Filings System

FIGURE 1 –LOAD AND RESOURCES

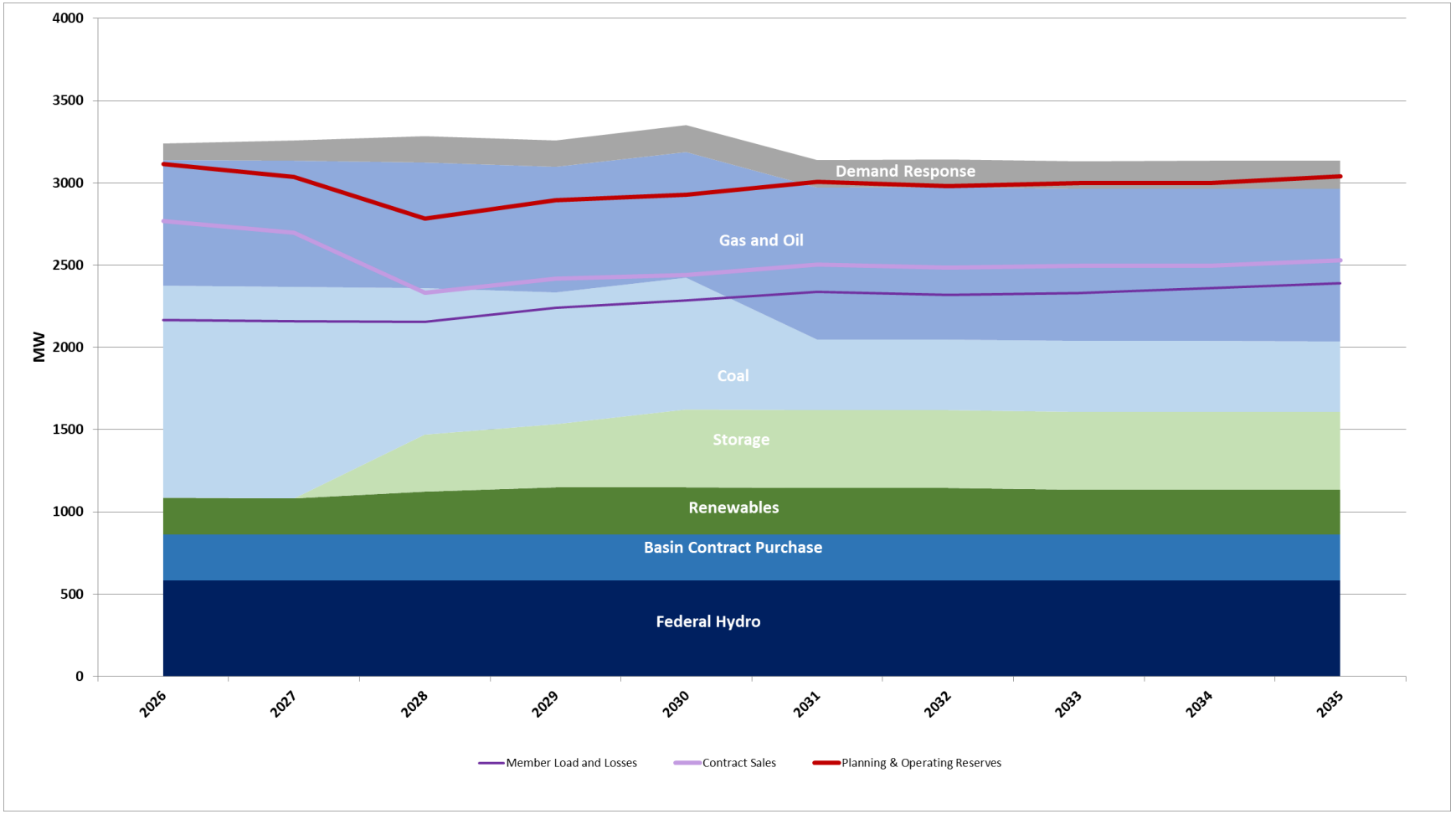

TABLE 1 – LOAD AND RESOURCES

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Federal Hydro	584	584	584	584	584	584	584	584	584	584
Contract Purchases	278	278	278	278	278	278	278	278	278	278
Renewables[4]	226	222	260	286	286	281	281	272	273	271
Demand Response	100	124	161	162	164	165	167	169	170	172
Coal Generation[5]	1287	1286	888	800	800	431	432	431	432	431
Gas & Oil Generation[6]	765	765	765	765	765	925	925	925	925	925
Storage[7]	0	0	349	383	474	474	474	474	474	474
Total Resources	3239	3257	3285	3259	3351	3138	3141	3132	3136	3135
Member Load and Losses[8]	2166	2160	2156	2241	2284	2337	2317	2332	2358	2390
Planning & Operating Reserves	348	341	451	476	489	505	498	502	502	511
Contract Sales	601	537	177	177	155	166	166	166	139	139
Total Obligations	*2001*	*1971*	*1781*	*1865*	*1906*	*1957*	*1936*	*1949*	*1948*	*1978*
Excess Resources	**123**	**219**	**501**	**364**	**422**	**131**	**160**	**133**	**136**	**95**

[4] Capacity is based on applying the effective load carrying capability by renewable technology to the nameplate of renewable resources.
[5] Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.
[6] Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.
[7] Capacity is based on applying the effective load carrying capability for storage to the nameplate of storage resources.
[8] Western Interconnection Load.

Tri-State's report covers its Utility Members as LSEs, for the portion of their loads served by Tri-State,[9] pursuant to §40-43-104(2), C.R.S.

In accordance with §40-43-104(1)(c), C.R.S., Tri-State understands that the Colorado Energy Office will, by July 1, 2026, utilize Tri-State's report and that of other LSEs to create an aggregated statewide report.

Submitted this 17th day of March, 2026.

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[9] Tri-State expects that certain Utility Members that are exiting Tri-State membership may supply separate RA Annual Reports, to the extent applicable.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-173
2024 NREL Lessons from Renewable Integration Studies



Maintaining Grid Reliability – Lessons from Renewable Integration Studies

Paul Denholm, Ilya Chernyakhovskiy, and Lauren Streitmatter

National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
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Maintaining Grid Reliability – Lessons from Renewable Integration Studies

Paul Denholm, Ilya Chernyakhovskiy, and Lauren Streitmatter

National Renewable Energy Laboratory

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Technical Report
NREL/TP-5C00-89166
April 2024

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Table of Contents

1 Introduction 1
1.1 Three Key Issues To Maintaining Bulk System Reliability With Increased Wind and Solar 1
1.2 Summary of Findings 2
1.3 How Have We Studied the Evolving Grid? 3
1.4 Study Geography 4
1.5 Studies Considered 5
2 Meeting the Ramp: Lessons From Variability Studies 7
3 Meeting the Demand: Lessons From Resource Adequacy Studies 10
4 Keeping the Grid Moving: Lessons From Frequency Stability Studies 13
4.1 Frequency Stability – Summary of the Issue and Study Approach 13
4.2 Study Findings 13
5 From Study to Practice: Where Are We Now and Where Are We Going? 16
5.1 Incorporating High Levels of Variable Generation in Utility Planning 16
6 Conclusions 18

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1 Introduction

In 2023, clean energy resources (including renewables and nuclear power) provided about 41% of electricity in the United States, with more than 16% of total generation provided by wind and solar—called "variable" renewable energy sources because of their daily and seasonal fluctuations in availability (U.S. Energy Information Administration 2024). The bulk power system, which supplies and transmits electricity, maintained high reliability throughout the year, showing that grid reliability is achievable as deployment of wind and solar has increased.

Wind and solar contributions to the nation's electricity mix are projected to grow significantly—Gagnon et al. (2024) project that wind and solar could provide more than 60% of national electricity generation by 2035 under existing polices. Maintaining high reliability in the bulk power system while increasing renewable resource deployment is a critical priority for electric grid planners, operators, and regulators.

The U.S. Department of Energy (DOE) and other organizations have sponsored numerous research studies over the last two decades to examine the effect of increased wind and solar deployment on grid reliability, including a number of studies that examine grids deriving more than 50% of annual energy from wind and solar. Here, we discuss key findings from both the research body of knowledge and real-world practice related to grid reliability, and we demonstrate how to plan for and achieve continued reliability in the future as wind and solar deployment increase.

1.1 Three Key Issues To Maintaining Bulk System Reliability With Increased Wind and Solar

Maintaining bulk system reliability requires balancing the supply of electricity with demand at various timescales, from less than a second to hours, days, and beyond.[1] Maintaining reliability with increased deployment of wind and solar at scale presents issues that can be summarized into three general categories:

1. **Responding to short-term variability of wind and solar generation.** The fluctuation of variable renewable energy supply was one the first concerns with wind and solar deployment. Output from these resources can vary over multiple timescales from seconds to hours with limited predictability. This variability and uncertainty can impact how the system is operated, so there has been considerable effort to study ways to mitigate these impacts.

2. **Ensuring enough generation to meet demand during all hours of the year.** Grid planners traditionally focused on meeting demand during peaks, like hot summer afternoons and cold winter nights. But with the growth of wind and solar, focus has shifted to maintaining an adequate mix of resources to meet demand in all hours, particularly where renewables are expected to replace traditional fossil-fueled generators.

[1] For additional discussion of the concept of power system reliability (including formal definitions of reliability elements), see North American Electric Reliability Corporation (2013).

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Planning is further complicated by the impact of new loads from electrification, which can also shift the timing of peak demands.

3. **Maintaining stability in the event of a grid disturbance.** One aspect of grid stability that relates to the deployment of wind and solar is frequency stability, or the ability to avoid large changes in frequency after a generator or transmission line failure. The concern is associated with the loss of traditional system inertia as renewable resources like wind and solar displace fossil-fueled resources, whose operating characteristics inherently provide inertia.[2]

1.2 Summary of Findings

Dozens of studies address various aspects of reliability with the increased deployment of renewable energy resources in regions across the United States. The studies examine contributions from renewables that range from 30% to 100% of total generation and show that these systems can achieve a desired level of reliability if appropriate measures are taken to change how the grid is planned and operated. These measures can be summarized in four categories:

1. **Short-term variability and uncertainty in renewable generation can be managed cost-effectively by increasing grid flexibility.** Many grid flexibility options have been deployed, including changing how the power system is scheduled, balancing supply and demand over larger regions, using energy storage and other quick-ramping resources, and employing new operating reserve approaches.
2. **Demand for electricity during all hours of the year can be met through a portfolio approach.** A portfolio approach aggregates variable renewable deployment with dispatchable resources like energy storage, existing and new fossil resources, and new "clean firm" technologies. Studies highlight the benefits of combining solar and storage to meet summer peaks. These studies also demonstrate that significant renewable resource contributions and deep decarbonization can occur as existing (and new) fossil resources transition from sources that provide energy during many hours of the year to resources that operate primarily during periods of low wind or solar output. Systems studies that approach or reach 100% clean energy demonstrate how clean firm technologies can replace existing fossil resources that are acting primarily as capacity resources.
3. **Increased utilization of power electronics supports frequency stability.** Frequency stability studies have demonstrated that grids can maintain reliable operation with greatly increased use of wind and solar. Along with energy storage, wind and solar resources use power electronics that can react very quickly to faults and provide frequency support to the grid—which can offset the decline in inertia.

[2] While this list covers most of the important issues evaluated in renewable integration and reliability studies, it is not comprehensive. There are other important issues that have been studied and some that require further study. These include voltage control and stability, system strength, transient stability, and fault current. These issues are not discussed further in this report.

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4. **Expanded transmission networks are central to increasing reliability.** Capacity expansion and chronological operational studies generally conclude that increased utilization of existing transmission and new transmission expansion are needed to cost-effectively achieve high contributions of wind and solar across the United States. This includes building out local transmission networks to access the best renewable energy resources as well as expanding transmission capacity between balancing areas and interconnections to move power from where it is available to where it is most needed. This also acts to reduce variability of the aggregated supply of renewable resources across various timescales.

These findings have been incorporated into current utility practices, which has led to instantaneous contributions of wind and solar of over 80% in several regions of the United States (Millstein, O'Shaughnessy, and Wiser 2023). Current utility plans now incorporate various approaches to achieving increased economic deployments of wind and solar while maintaining reliability standards.

1.3 How Have We Studied the Evolving Grid?

Dozens of studies have been performed that examine one or more of the three key issues using a variety of tools and approaches, but they have some common elements.[3] They generally start with establishing the scenarios to be studied, including the generation mix in some future year. The scenarios can be developed manually or by using a capacity expansion model that identifies the optimal (least-cost) mix of resources that can meet the target grid conditions.[4]

Once the future resource mix and study conditions are established, a variety of tools may be used, depending on the study goal:

- **Variability studies** are used to evaluate how the mix of generation, storage, and transmission resources can respond to variations in supply from wind and solar.[5] Many of the earliest studies were designed to examine the avoided costs that result from reduced output from fossil-fueled plants. They often focus on the impact of variability on the existing fossil-fueled generation fleet to ensure the system can react quickly enough and provide adequate levels of operating reserves. The studies also often examine the impact on power plant costs as the plants spend more time varying output and more frequently stop and start. Variability studies use a production cost model that simulates the chronological operation of the grid at an hourly (or sub-hourly) resolution and calculates the cost of operating the system.[6] These studies typically evaluate reliability over a single year using historical weather patterns.
- **Resource adequacy studies** evaluate the probability that there will be unserved energy (power outages) that might result from some combination of insufficient supply of

[3] A more detailed description of study methods is provided in Katz and Chernyakhovskiy (2020).
[4] Capacity expansion models are not unique to renewable studies. They have been used as part of utility planning processes for decades. For additional discussion see Murphy and Weiss (1990) and Cole et al. (2017).
[5] While production cost models typically do not simulate the more rapid variations in supply in the regulation time frame, they do ensure adequate reserves can respond to more rapid variation.
[6] These tools use detailed datasets that include individual generator performance and how fast they can vary output.

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generation resources or higher-than-average demand.[7] These studies often include additional consideration of forecasted changes to demand patterns due to energy efficiency and electrification of end uses. The studies perform chronological simulations over at least one year of future grid conditions, examining in detail the potential shortfall of supply and potential mitigation measures during periods of high demand and during periods of lower renewable energy supply, often using the same production cost models as variability studies. However, resource adequacy studies may also use additional tools that consider uncertainty in resources over longer time periods and a broader set of possible weather conditions (or use a single tool that combines both chronological simulations with the probabilistic component).

- **Frequency stability studies** examine the ability of the grid to maintain system frequency within a tolerance. Unlike the previous studies that examine one or more full years, these studies typically only consider a few moments in time, often those where the system may be particularly vulnerable to a fault, such as periods where many thermal generators have been turned off and there is less inertia on the grid. They use a class of tool known as a power flow model to simulate the dynamic operation of the grid immediately following a fault and can identify conditions where frequency stability may be compromised.[8]

It is important to note that most studies are iterative in nature—they often discuss reliability concerns, identify one or more potential solutions, and evaluate the solutions to ensure the reliability target or standard is met. The process of studying the grid has also evolved as lessons from real-world experience have been incorporated and as modeling tools have improved with increased ability to examine variable and inverter-based resources. Historically, most studies have focused on large-scale transmission and generation-based options, but there is increasing recognition of the potential for distributed resources to provide grid services.

1.4 Study Geography

The studies vary across geographical scales, but there are two main types of geographical regions studied: balancing areas and interconnections. In the U.S. power grid, supply and demand are balanced in 66 balancing areas (Figure 1).[9] Therefore, many studies of variability and resource adequacy focus on individual balancing areas. Many studies also examine the potential benefits of improved coordination across multiple balancing areas, including the potential to import and export energy during periods of high system stress or excess renewable production. Balancing areas are electrically interconnected into one of three large, independent grids known as interconnections: Eastern Interconnection (EI), Western Interconnection (WI), and Electric Reliability Council of Texas (ERCOT).[10]

[7] This is an oversimplified definition of resource adequacy, which includes elements of addressing short-term variability. For additional discussion, see Energy Systems Integration Group (2021).
[8] These models are often referred to as power flow models because one of their main applications is to understand the flow of power along various transmission lines to ensure the lines are not overloaded.
[9] The number and size of balancing areas have changed over time.
[10] The EI and WI includes much of Canada and the WI includes a small part of Mexico.

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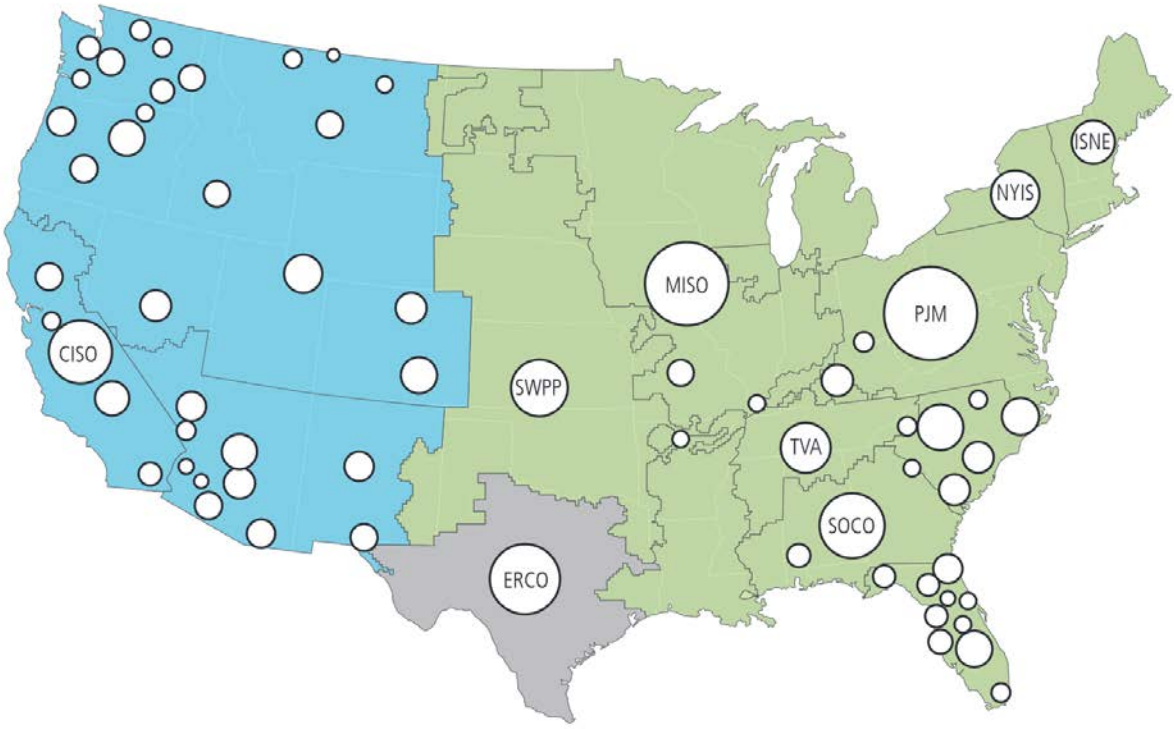

Figure 1. The U.S. power grid consists of 66 balancing areas and three interconnections (U.S. Department of Energy 2017).

1.5 Studies Considered

Table 1 lists variability and resource adequacy studies that examine annual renewable generation contributions of between 30% and 100% in various regions of the United States that we considered in this review. This table is not intended to be comprehensive and only lists studies that include detailed chronological simulations. Table 2 lists studies that focus on frequency stability.

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Table 1. Variability and Resource Adequacy Studies

Region	Cite	Renewable Contribution	Study Focus
WI	GE Energy 2010	35%	Variability
WI	Lew et al. 2013	33%	Variability
EI	Bloom et al. 2016	30%	Variability
EI and WI	Bloom et al. 2022	40%	Variability, Resource Adequacy
North America	Brinkman et al. 2021	70%–80% by 2050	Variability, Resource Adequacy
USA	Mai et al. 2012	80% by 2050	Resource Adequacy, Variability
California	Brinkman et al. 2016	56%	Variability
Los Angeles	Cochran et al. 2021	100% by 2035/2045	Variability, Resource Adequacy
New England	Boughan et al. 2022	95% carbon free	Resource Adequacy
Pacific Northwest	Ming et al. 2019a	60%–100% by 2050	Resource Adequacy
California	Ming et al. 2019b	100% by 2045	Resource Adequacy
California	Douglas et al. 2009	33% by 2020	Variability
PJM	GE 2014	30%	Variability
Midcontinent System Operator	Prabhakar et al. 2021	>50%	Variability
Southwest Power Pool	Southwest Power Pool 2016	60%	Variability
PJM	PJM 2021	50%	Variability, Resource Adequacy
New York	NYISO 2022	70%	Resource Adequacy
New England	Mettetal et al. 2020	60% renewable/ 70% clean	Resource Adequacy, Variability

Table 2. Frequency Stability Studies

Region	Year	Max. Instantaneous Inverter-Based Resource Contribution
WI	Miller and Pajic 2018	~60%
WI	Miller et al. 2014	53%
ERCOT	Miller et al. 2008	~20%
EI	Miller et al. 2013	25%
WI	Gevorgian et al. 2015	80%
WI	Tan et al. 2018	80%

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EI, WI, ERCOT	Liu et al. 2018	80%

2 Meeting the Ramp: Lessons From Variability Studies

Early studies of variability introduced several important concepts in power system planning and operation with increased use of renewable energy. One is the concept of net load, or load minus the contribution of renewables. Net load represents the energy that must be served by the balance of the system fleet. Figure 2 illustrates a large increase in net load in the late afternoon that occurs in a system with significant solar contribution.

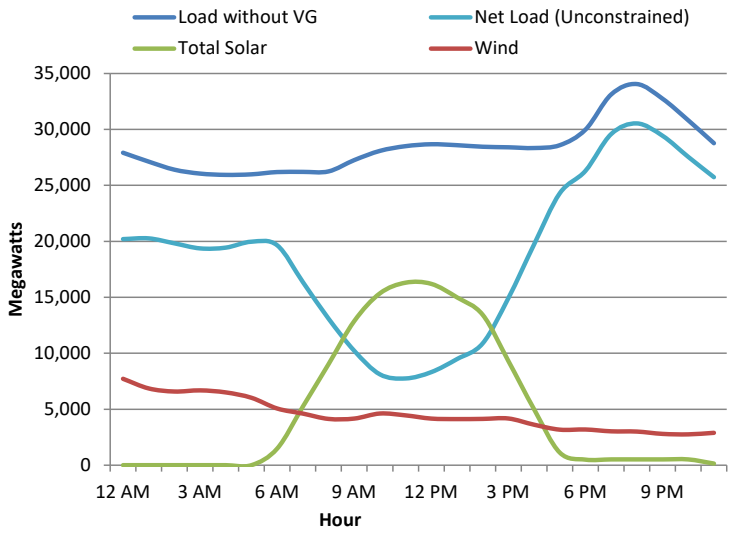

Figure 2. Concept of net load.

VG = variable generation

Another important concept introduced by these early studies is the "flexibility supply curve," which suggests that a variety of options should be considered for the grid to address the increased ramping requirements along with the uncertainty of renewable supply. Wind and solar can then be deployed at the lowest possible cost. Figure 3 shows an example flexibility supply curve; many of these options have been deployed in the past two decades and have helped achieve the levels of renewable deployment to date, discussed in Section 5.

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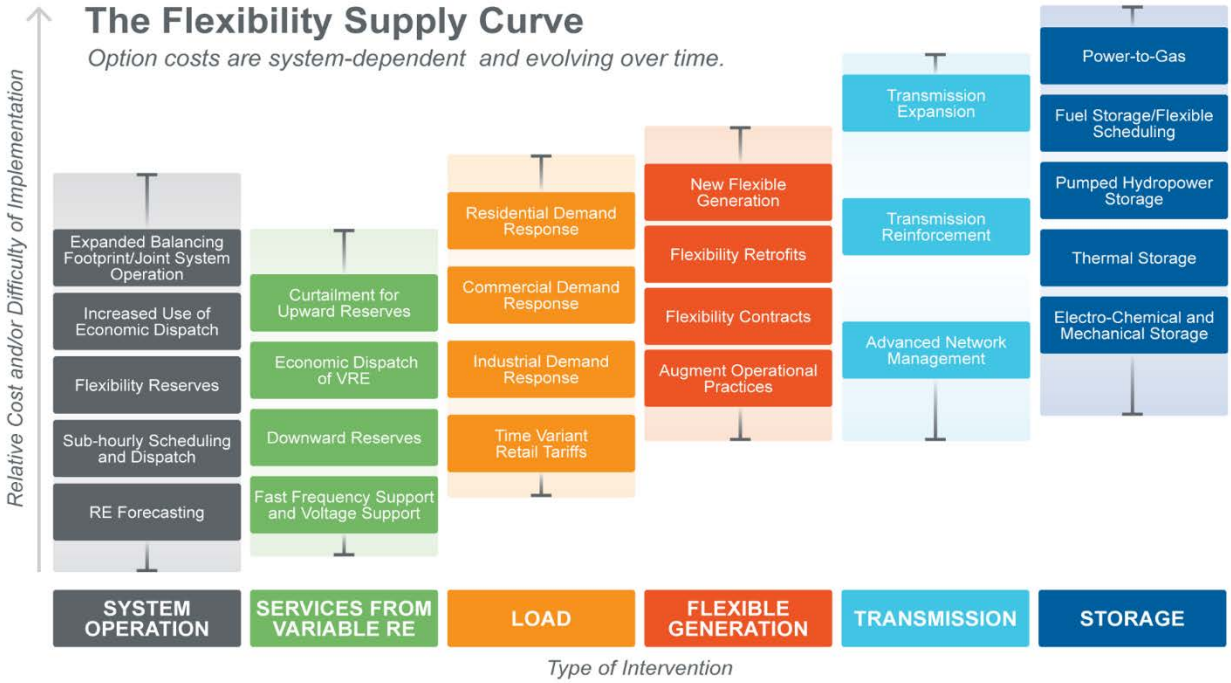

Figure 3. Example of a flexibility supply curve[11]

As an example, early variability studies identified the role of geographic diversity in reducing the variability of renewable resources. While the output of a single, small solar system can change rapidly due to passing clouds, the aggregated output of many, geographically dispersed systems is much smoother and can be better forecasted (Zhang, Hodge, and Florita 2013). Figure 4 shows an example comparing the variability of the solar resource at a single site vs. multiple sites and shows that variability typically occurs over longer timescales (minutes to hours), which reduces the potential need for expensive operating reserves. A similar benefit of aggregation occurs with wind generators.

By balancing supply and demand over larger regions (via improved balancing area coordination or creating larger balancing areas), the variability of renewables (and also of regional loads and other generation resources) is significantly reduced (Denholm and Cochran 2015). System operation costs have therefore been reduced, and the benefits of renewables in offsetting fossil fuel use have increased. Early assumptions about the need for "1:1 spinning backup" from fossil-fueled resources have largely been refuted, and studies (along with real-world experience) have demonstrated that the costs of increased fossil-fuel plant cycling are small compared to the fuel cost savings from reduced fossil fuel use (Lew et al. 2013).

[11] Note that this chart is intended to illustrate the concept of a supply curve; the order of the individual components is not definitive.

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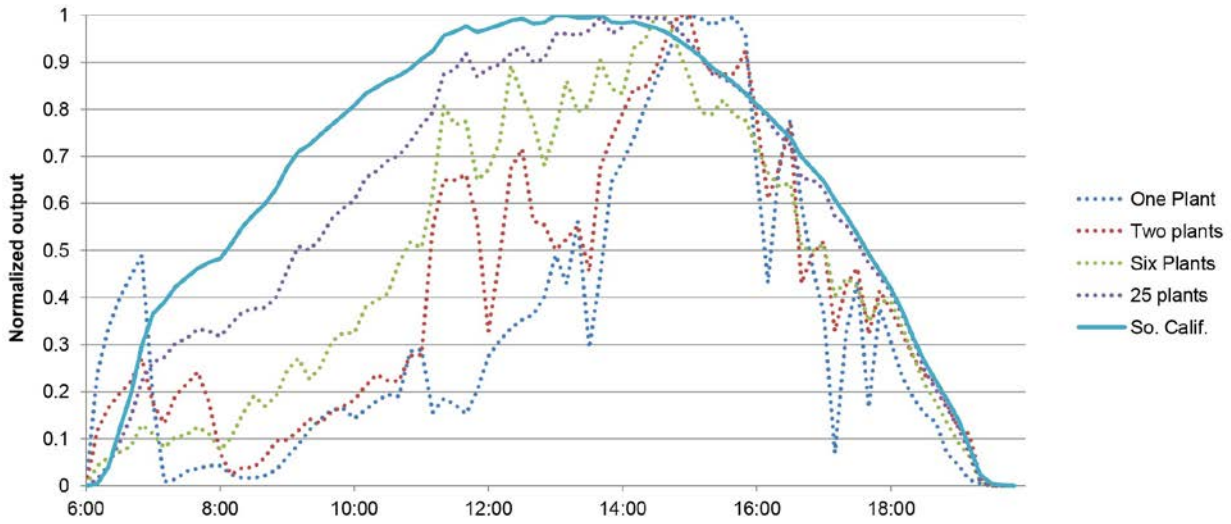

Figure 4. Normalized PV output for increasing aggregation of PV plants in Southern California on a partly cloudy day

Studies have also identified benefits related to improved renewable production forecasting and shorter-term generator scheduling in response to changing conditions. Several regions have introduced flexible ramping reserves specifically to address sub-hourly renewable variability. Flexible ramping reserves provide a lower-cost alternative to addressing solar and wind variability with higher cost regulating reserves, which may have response rates faster than are actually needed (Denholm, Sun, and Mai 2019). Several regions also now allow wind and solar to provide operating reserves, particularly during periods of very high renewable generation when the output of fossil fuel generators is substantially reduced.[12]

As a result of these actions, several regions have met or exceeded the levels of renewable deployment evaluated in the earliest studies, demonstrating the benefits of careful study and planning. Many forward-looking studies examining even greater renewable deployment have identified additional options to address growing variability. These options include greater use of storage and increased use of solar and wind dispatch, where the output of renewable generators is controlled to reduce ramp rates and to provide reserves by operating at partial output in a manner similar to the way in which conventional plants provide reserves.[13] More coordination across larger geographical areas can provide additional benefits—some studies suggest benefits related to coordinating grid operations across much larger regions, and potentially across the interconnections, through expanded transmission capacity.

[12] This is already common practice in several regions, most notably in Texas (Milligan et al. 2015; Chernyakhovskiy et al. 2019).
[13] This requires the wind or sun to be available, but if it is not, then variable generation does not add any reserve requirements during that period of time.

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3 Meeting the Demand: Lessons From Resource Adequacy Studies

With the growth in wind and solar deployment and the increase in fossil-fueled generator retirements, more recent studies have shifted focus to resource adequacy. These studies are often in the context of regional renewable and climate goals, and many are focused on renewable contributions greater than 50%. The studies all identified pathways to achieve high levels of renewable contributions while maintaining resource adequacy targets, which often aim for an expected loss of load of less than 0.1 days per year (Electric Power Research Institute 2022). The studies identify several important concepts:

1. Resource adequacy is a measure of the system as a whole, considering the total system demand and the combined contribution of all generators and the transmission network.

2. Resource adequacy should be considered at all hours of the year, not just during periods of traditional demand peaks.

3. Fossil resources will increasingly transition from acting as energy resources (that run frequently and serve much of the day-to-day demand for electricity) to acting as capacity resources (that run less frequently, mainly during periods of very high demand or low renewable supply).

4. Approaches to maintain resource adequacy vary depending on the level of renewable contribution, decarbonization targets, and how far in the future the study examines.

In most regions, wind and solar are being added to a much larger system, where existing hydropower and thermal plants provide the majority of capacity needed to maintain resource adequacy. As a result, ensuring resource adequacy in the near term means incremental additions are needed to replace retiring capacity or to address load growth. In addition to traditional generation resources, other options to provide resource adequacy include transmission, storage, and demand-side resources.

New approaches must be considered when evaluating the potential resource adequacy contributions of renewable resources. For example, combinations of wind, solar, and storage can contribute to resource adequacy, but unlike thermal and hydropower resources, these contributions depend on the amount of the resources already installed. For example, Figure 5 shows the peak summer load in Texas during two days in 2022, and the impact on net peak load after the contribution of solar energy on this day. In this example, there is a substantial reduction in net demand, reducing the need for fossil-fueled resources to maintain resource adequacy during the summer peak. However, the net load has been shifted to the early evening when solar output has fallen, and doubling the amount of solar (shown by the orange line) would provide no further reduction in net load. This is a significant limiting factor for solar to (by itself) provide resource adequacy in grids with even greater deployment of renewables. At the same time, the change in net load shape also makes it easier for storage to meet the remaining (shorter) summer peaks, demonstrating considerable synergy between the two technologies.

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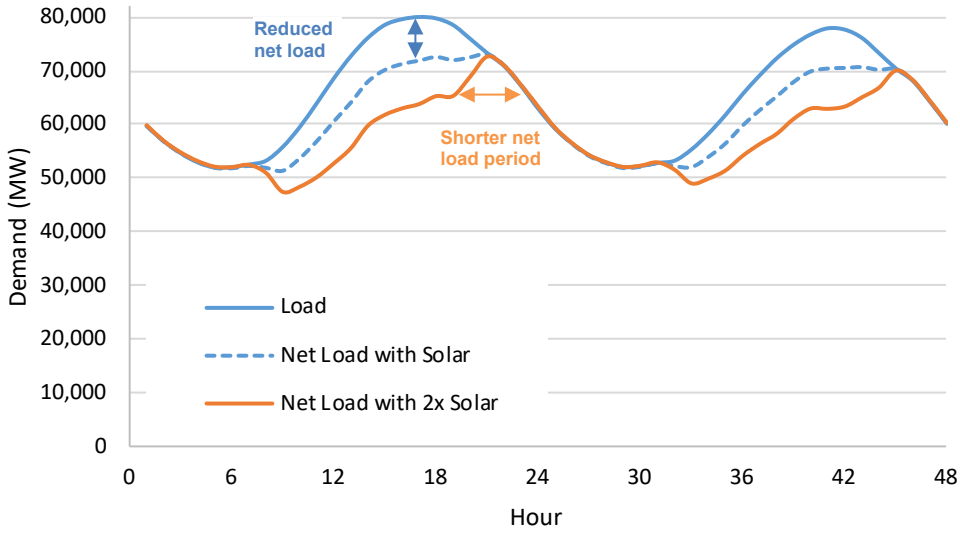

Figure 5. Example of the impact of solar on net load in ERCOT on July 20–21, 2022. The solar already installed has reduced the net load, providing resource adequacy benefits. Additional solar has limited ability to reduced net load but shortens the length of the net load peak, making it easier for shorter-duration energy storage (or demand response) to provide additional resource adequacy benefits.

The role of fossil-fueled resources in high renewable studies varies considerably, depending largely on renewable energy and decarbonization targets. For example, the results from one nationwide grid study in Figure 6 show the energy contribution (top) and contribution toward resource adequacy (bottom) provided by different resources under increasing levels of annual renewable contribution ranging from 57% to 100% (Cole et al. 2021). In many cases, keeping existing (or even building new) fossil-fueled resources is often identified as the least-cost approach to maintaining resource adequacy while transitioning to greater levels of decarbonization. For example, in the case of achieving 57% contribution from renewables, fossil-fueled generation provides about 30% of annual electricity generation (energy) but about 60% of firm capacity. Thus, as the contribution from renewables increases, fossil-fueled generators transition to act primarily as a source of capacity.

There is considerable interest in clean firm technologies that can meet demand during extended periods of lower wind and solar output such as seasonal storage.[14] However, studies have demonstrated that annual contributions of 80% can be achieved without significant deployments of new clean firm technologies by deploying a mix of renewable energy, storage, and potentially significant amounts of existing (or new) fossil-fueled generators. The fossil-fueled generators are maintained in the system primarily to provide resource adequacy (not energy); because they operate infrequently, they produce relatively few emissions. The study shown in Figure 6 does not deploy clean firm technology until annual renewable contribution exceeds 90%, (in part due to the assumption of nationwide coordination of the power grid and large-scale deployment of interregional transmission). This emphasizes the potential to get very deep decarbonization while

[14] While no technology is truly "firm" (having 100% capacity credit), the term clean firm refers to technologies that are both low emission and have high capacity credit.

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maintaining a large amount of fossil-fueled capacity used only during periods of extremely high demand or low wind and solar.

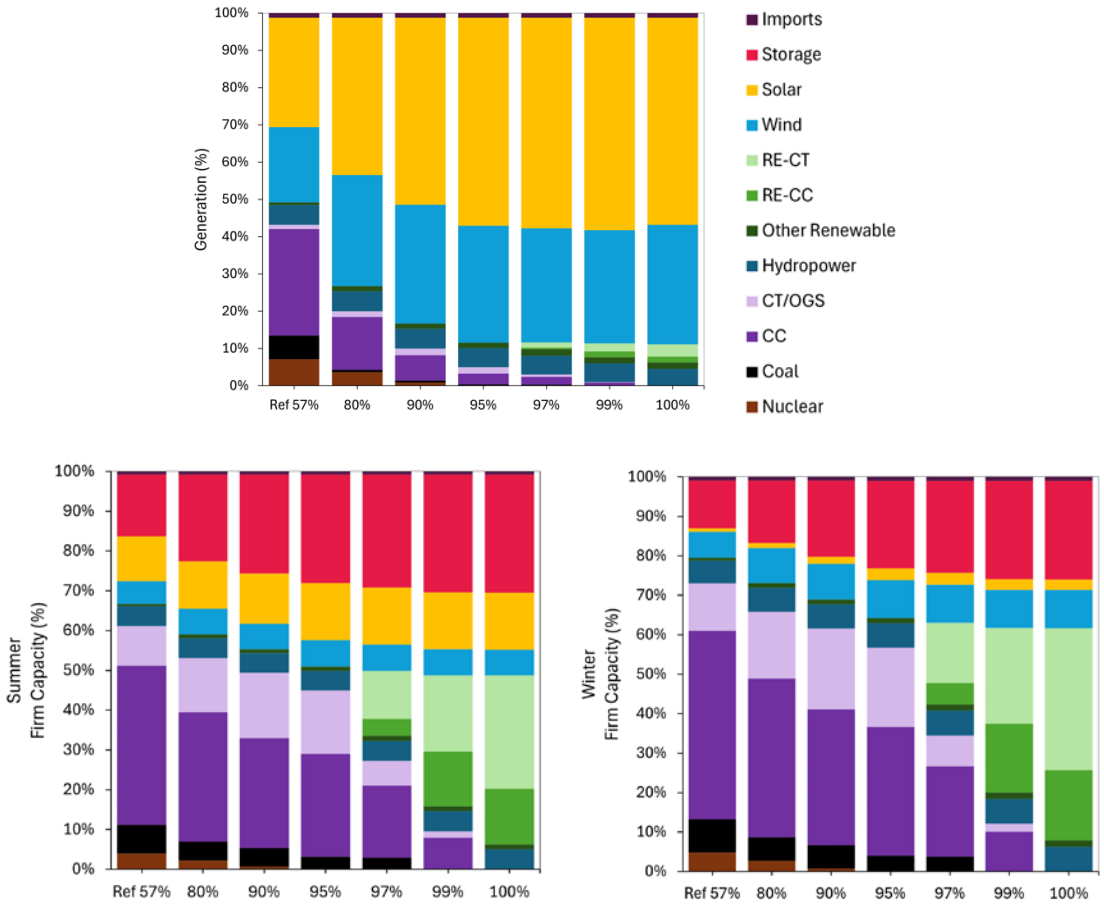

Figure 6. Example of an energy mix (top) and firm capacity (bottom) from one study of the evolution to 100% clean energy, where fossil fuels continue to provide a large amount of capacity but with a decreasing amount of energy (Cole et al. 2021).

There is considerable uncertainty about which technologies might be the most cost-effective to provide the mix of capacity that will likely be required in 100% clean energy systems. They would be required to provide reliable capacity during multiday periods in all seasons. Many of the proposed technologies envisioned in 100% clean energy scenarios (including carbon capture, hydrogen, or next-generation nuclear) have yet to be deployed at scale. Many of these technologies, particularly hydrogen, will require significant changes to infrastructure and are associated with changes to the entire energy system beyond the electricity grid.

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4 Keeping the Grid Moving: Lessons From Frequency Stability Studies

4.1 Frequency Stability – Summary of the Issue and Study Approach

Studies to date provide a strong indication that frequency stability can be maintained with understood technologies, including some technologies that have already been deployed at scale. The current grid relies largely on generators that spin at a nearly constant frequency. In the moments following a sudden loss of supply, such as a transmission line outage or generator failure, the supply/demand imbalance can result in a decline in frequency as the system slows down. But some of the inherent stored energy in existing generators (inertia) is injected into the grid automatically after a fault, which keeps the system from slowing down too fast and gives the system time to detect and respond to the loss of supply (Denholm et al. 2020).

Inertia is part of the more general category of "frequency response," which consists of several processes that detect and respond to changes in frequency and prevent frequency from dropping below a minimum level at which the system must initiate controlled blackouts to prevent damage to equipment. Frequency response has historically been provided by synchronous generators in thermal (fossil fuel and nuclear) and hydropower plants.

Wind, solar, and battery storage use power electronics (inverters) to provide grid-compatible electricity and do not behave the same way as synchronous generators. These inverter-based resources (IBRs) do not automatically provide frequency response in the seconds and minutes following a grid event or disturbance. As a result, replacing conventional generation with IBRs can reduce traditional frequency response, including real inertia, and can decrease the stability of the power system if no mitigating actions are taken. This means there is a need to study the impact of IBRs and develop methods to increase their use without compromising frequency stability.

4.2 Study Findings

There are several consistent themes among frequency stability studies to date. They all demonstrate that as IBRs are added, their contribution can lead to synchronous generators being turned off during very windy or sunny periods. This leads to a reduction in physical inertia and inherent frequency response.

Multiple solutions have been identified in these studies to mitigate the decline in physical inertia and maintain sufficient frequency response. The main approach studied is the use of fast frequency response (FFR), which exploits the ability of electronic devices to respond very rapidly to changes in frequency. Fast frequency response is obtained from multiple sources, including flexible loads that are paid to disconnect for very short periods of time or IBRs that can rapidly increase output. Energy storage, wind, and solar can reduce output during periods when there is available energy from wind and solar resources and then rapidly increase output in response to a fault. All of these devices can respond faster than conventional generators; this rapid response significantly decreases the amount of physical inertia required.

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The amount of mitigation required depends significantly on the size of the grid, the amount of IBRs deployed, and the makeup of the remaining generation fleet. The need is smallest in large grids that have a large contribution of low-carbon resources that use synchronous generators, including hydropower, nuclear, biomass, and geothermal. Even with significant deployment of IBRs, studies of the EI (serving about 70% of the nation's electricity demand), show that this grid can support extremely large amounts of renewable resources with small impact on frequency stability. The WI is smaller, but also has significant clean synchronous generation, and the need for FFR is relatively small, even with large contribution from IBRs (Denholm et al. 2020). Figure 7 shows an example during a period when IBRs are providing 60% of the WI's entire generation (Gevorgian, Zhang, and Ela 2015). This chart shows the frequency after the worst-case fault the system is expected to address. In cases where no FFR is deployed, the frequency falls below 59.5 Hz, where load shedding must occur. But the addition of FFR from wind generation avoids this large drop in frequency and maintains stable operation during a worst-case scenario.

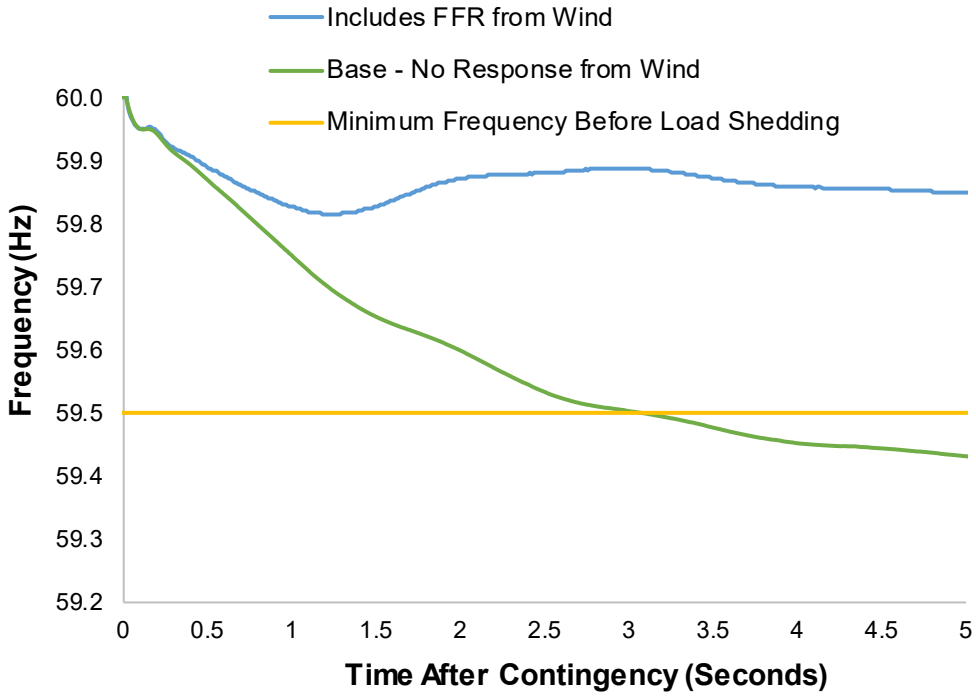

Figure 7. Example of a study demonstrating the benefit of fast frequency response from wind in a grid with decreased inertia (Gevorgian, Zhang, and Ela 2015).

The need to address the decline in inertia is greatest in the smallest of the three grids (ERCOT), which does not have significant hydropower, geothermal, or biomass combustion.[15] ERCOT has already made changes to system operation, including using FFR, largely from loads. ERCOT has also required IBRs to provide frequency response services.

[15] Additionally, ERCOT has a contingency size that is about the same as that of the WI, which increases the need for frequency response.

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IBRs are increasingly required by state and federal standards to provide grid services such as frequency response (FERC 2018). In addition to FFR, there are additional well-proven approaches that maintain physical inertia such as using clean energy resources that use synchronous renewable generators, or stand-alone devices that provide physical inertia without requiring a generator (synchronous condensers).

Finally, it is possible to operate grids without large amounts of physical inertia by using grid-forming inverters.[16] These devices have been deployed in smaller grids, but there have been limited studies of the potential use of these devices at the interconnection level, which is required to study system frequency stability.

Overall, multiple studies indicate that the use of measures such as FFR can mitigate the loss of synchronous generation due to the variable generation that will likely be deployed in the coming decade, especially in the larger EI and WI grids that serve more than 90% of the country. The biggest outstanding question is which combination of solutions might achieve the lowest cost.[17]

[16] While current inverters (known as grid-following inverters) can provide frequency response, they cannot inherently and independently create the alternating current waveform the grid uses as a reference. This is one of the main distinctions between these and grid-forming inverters, which create the waveform.

[17] There are a number of other reliability issues related to large-scale IBR deployment beyond frequency that are not discussed here. Many are discussed by NERC (2023).

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5 From Study to Practice: Where Are We Now and Where Are We Going?

While the U.S. power grid is well below 100% variable renewable energy on average, several regions in the country (and many around the world) have achieved very high contributions from renewable energy over shorter timescales. Figure 8 illustrates the average and maximum hourly contribution from wind and solar resources for several regions in 2023. The data in Figure 8 do not include the contribution of rooftop or other behind-the-meter (BTM) solar or other renewable or clean electricity resources; however, they demonstrate the ability of the system to remain reliable while addressing both variable supply and (in the case of ERCOT) high levels of IBR contributions.

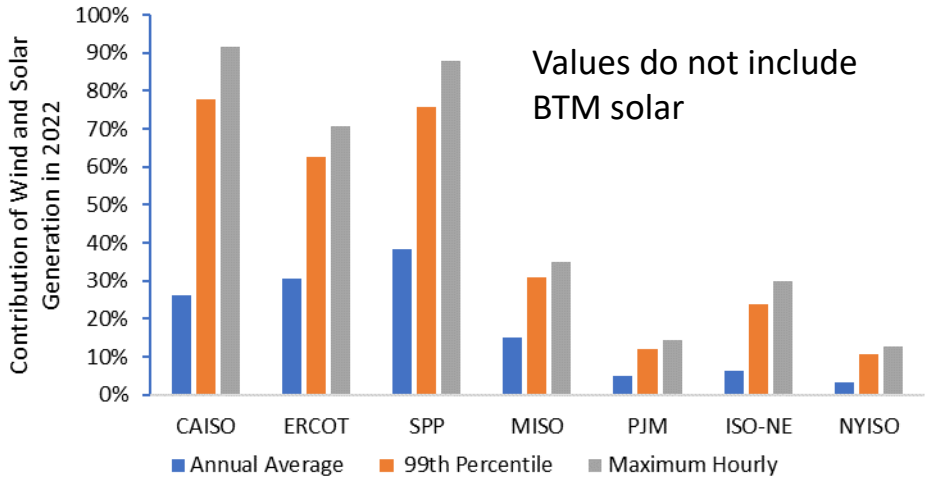

Figure 8. Average and maximum hourly contribution of wind and solar resources in 2023[18]

5.1 Incorporating High Levels of Variable Generation in Utility Planning

The lessons learned from studies and real-world experience is now being incorporated into utility planning for future growth in renewable energy. With wind and solar providing the lowest-cost source of new electricity, and with storage providing cost-effective peaking capacity, many utility resource plans include significant deployment of these technologies. Utility plans account for the low cost of energy from wind and solar, the limits of wind and solar to provide energy during peak periods, and the need to address the variability and uncertainty of these resources—it is well understood that 1 MW of variable generation capacity does not generally provide the same resource adequacy value as 1 MW of retiring fossil-fueled capacity.

[18] Data provided by Dev Millstein, available at https://emp.lbl.gov/renewables-and-wholesale-electricity-prices-rewep. It should be noted that all regions except ERCOT are interconnected to other grids which mitigates some of the challenges, and there are often other generation resources in these regions that are operating and exporting energy.

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Recent resource plans filed to regulatory agencies reflect the expectations that wind and solar can be part of the least-cost mix of resources while maintaining reliable electricity. These plans indicate corporate intentions to deploy the proposed generation capacity and the proposed mix of resources to meet reliability standards required by state and regional regulatory agencies. Table 3 lists five filed resource plans that achieve significant contribution of renewable energy while explicitly stating that the systems are expected to maintain reliability standards.

Table 3. Utility Resource Plans Demonstrating the Mainstream Nature of High Renewable Energy Contribution in Plans That Include Reliability Standards

Utility and Integrated Resource Plan Year (including link to study)	% Renewable Energy	Notable Reliability-Related Findings
Southern California Edison (2022)	90% by 2035, 95% by 2040	"Portfolio passes both the 1-in-10 LOLE reliability assessment and the feasibility and operability (emissions) check in PCM"a
Puget Sound Energy (2023)	85% by 2030, 100% by 2045	Scenarios satisfy PRM and include additional capacity for 5% LOLP a
Appalachian Power Company (2022)	53% by 2036, 100% by 2050	Scenarios achieve "reliability/reserve margin requirements as set forth by PJM"
Public Service Co of Colorado (2022)	83% by 2028	The plan "meets resource adequacy needs"
Indiana Michigan Power (2021)	~50%–55% by 2041	"The Preferred Portfolio includes additions that when added to the Company's current resources, … ensure the reliable supply of electricity while also maintaining PJM capacity requirements and supporting resource adequacy."

[a] LOLE = loss of load expectation; PCM = production cost model; LOLP = loss of load probability

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6 Conclusions

Over the past two decades, dozens of studies have been conducted to evaluate questions associated with maintaining reliability in power systems with an increased deployment of variable renewable energy (wind and solar). These studies have identified approaches to cost-effectively address the variability and uncertainty of solar and wind resources. Many of these approaches have been implemented, enabling a growing contribution of variable renewable energy resources in today's grid. These studies also identify pathways to accommodate future growth, including addressing the changing role of traditional generators from energy resources to capacity resources. Studies have also identified how new technologies can help maintain grid stability. These lessons can support current utility plans to develop large amounts of economic renewable energy deployments while maintaining state and federal reliability standards.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-174
2021 NREL North American Renewable Integration Study

NREL

The North American Renewable Integration Study: A U.S. Perspective





Gregory Brinkman,[1] Dominique Bain,[1] Grant Buster,[1] Caroline Draxl,[1] Paritosh Das,[1] Jonathan Ho,[1] Eduardo Ibanez,[2] Ryan Jones,[3] Sam Koebrich,[1] Sinnott Murphy,[1] Vinayak Narwade,[1] Joshua Novacheck,[1] Avi Purkayastha,[1] Michael Rossol,[1] Ben Sigrin,[1] Gord Stephen,[1] and Jiazi Zhang[1]

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The North American Renewable Integration Study:

A U.S. Perspective

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Preface

This report is one of four reports published as part of the North American Renewable Integration Study, or NARIS:

- *The North American Renewable Integration Study: A U.S. Perspective* (this report)
- *The North American Renewable Integration Study: A U.S. Perspective—Executive Summary*
- *The North American Renewable Integration Study: A Canadian Perspective*
- *The North American Renewable Integration Study: A Canadian Perspective—Executive Summary*

For more information about NARIS, see www.nrel.gov/analysis/naris.html.

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

Acknowledgements

The North American Renewable Integration Study (NARIS) was a multiyear, international effort on which many institutions collaborated and to which many individuals contributed. We would like to thank everyone who was involved in the study.

Members of the NARIS Technical Review Committee—which included experts representing approximately 50 utilities, grid system operators, and industry organizations throughout North America—helped guide the study assumptions, data, and methodologies to address relevant questions. Although the committee members helped review the report, it might not reflect the specific views or interpretations of any member of the committee or their institution. We would like to thank everyone who attended committee meetings (in person and virtual) or provided guidance during the study process, including those who provided specific comments on this report.

The authors would like to extend a special thanks for serving on the NARIS management team to Charlton Clark, Guohui Yuan, Sam Bockenhauer, Jian Fu, Tracey Kutney, Tom Levy, and Bronwyn Lazowski, and to Aaron Bloom for inspiration and support.

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List of Acronyms and Abbreviations

AB	Alberta
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BAU	business as usual
BC	British Columbia
CAISO	California Independent System Operator
CAMX	California and Mexico
dGen	Distributed Generation Market Demand
DPV	distributed photovoltaics
ECMWF	European Centre for Medium-Range Weather Forecasts
EIA	Energy Information Administration (United States)
ERCOT	Electricity Reliability Council of Texas
EUE	expected unserved energy
FRCC	Florida Reliability Coordinating Council
HQ	Hydro Quebec
HVDC	high-voltage direct current
IESO	Independent Electricity System Operator
ISO	independent system operator
LCOE	levelized cost of electricity
LOLE	loss-of-load expectation
LOLH	loss-of-load hours
LTRA	Long-Term Reliability Assessment
MAE	mean absolute error
MH	Manitoba Hydro
MISO	Midcontinent Independent System Operator
MWh	megawatt-hours
NARIS	North American Renewable Integration Study
NEB	National Energy Board (Canada)
NEM	net energy metering
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool
NYISO	New York Independent System Operator
PCM	production cost model
PRAS	Probabilistic Resource Adequacy Suite
PRODESEN	Programa de Desarrollo del Sistema Eléctrico Nacional
PV	photovoltaics
ReEDS	Regional Energy Deployment System Model
reV	Renewable Energy Potential Model
RMRG	Rocky Mountain Reserve Group
RTO	regional transmission organization
SENER	Secretaría de Energía de México
SPP	Southwest Power Pool
SRSG	Southwest Reserve Sharing Group
TEPPC	Transmission Expansion Planning Policy Committee

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TWh	terawatt-hours
TW-mi	terawatt-miles
USD	U.S. dollars
VG	variable generation
WECC	Western Electricity Coordinating Council
WIND	Wind Integration National Dataset
WRF	Weather Research and Forecasting

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Table of Contents

1 Introduction 1
1.1 Motivation 3
1.2 Scenario Overview 5
1.3 Assumptions and Limitations 10
2 Data and Methods 11
2.1 Methods and Models 11
2.1.1 Capacity Expansion Modeling: ReEDS 12
2.1.2 Distributed Generation Modeling: dGen 16
2.1.3 Production Cost Modeling: PLEXOS 21
2.1.4 Resource Adequacy Modeling: PRAS 25
2.2 Data 29
2.2.1 Wind and Solar Resource 29
2.2.2 Load 31
2.2.3 Hydropower 32
3 Results 36
3.1 Scenario Overview 36
3.2 Adequacy 39
3.2.1 Resource adequacy can be maintained in low-carbon scenarios through 2050. 39
3.2.2 All generation types can contribute to reliability in future scenarios. 42
3.2.3 Thermal generation operates differently in future scenarios and provides more adequacy than energy. 46
3.3 Transmission 49
3.3.1 Cooperation and transmission between regions and countries leads to economic and adequacy benefits. 50
3.3.2 Utilization of transmission infrastructure is very high. 60
3.4 System Flexibility 63
3.4.1 Operational flexibility comes from transmission, flexible operation of hydropower and thermal resources, storage, and curtailment of wind and solar generation 63
3.4.2 Less than 10% of potential wind and solar is curtailed. 66
3.4.3 Hydropower contributes significantly to energy, adequacy, and flexibility 68
3.4.4 Hydropower flexibility reduces system costs by more than $2 billion per year. 70
3.4.5 Hundreds of gigawatts of storage could be installed if costs came down significantly. 73
3.5 Scenario Comparisons 74
3.5.1 Emissions drop substantially in all scenarios. 74
3.5.2 Distributed generation is likely to play a significant role in generation; costs strongly impact adoption. 75
3.5.3 Total costs are more sensitive to electrification and assumptions about wind and solar costs than carbon limits. 79
3.5.4 Widespread electrification requires approximately doubling infrastructure investment from other core scenarios; further research is needed. 80
3.5.5 Using better information during unit commitment reduces costs and curtailment 84
4 Discussion and Future Work 85
5 References 87

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

List of Figures

Figure 1. North American wind (top) and solar (bottom) resource 4
Figure 2. Installed hydropower and transmission lines of North America 5
Figure 3. Comparison of core scenarios in NARIS 6
Figure 4. Modeling flow 11
Figure 5. ReEDS U.S. zonal representation 13
Figure 6. Cost comparison for wind (left) and solar PV (right) in the 2018 ATB and the 2020 ATB 16
Figure 7. Distributed PV resource quality by country 18
Figure 8. Distributed PV resource quality within the United States by sector 18
Figure 9. Cost trajectories for distributed PV 19
Figure 10. Sample PLEXOS output of U.S. generation dispatch stack for the week of June 24 (2050 Low Cost VG scenario) 21
Figure 11. Simulation steps to run the PCM 23
Figure 12. Transmission network representation in PRAS 26
Figure 13. Diagram of PRAS zonal balancing 27
Figure 14. The three domains used in NARIS for wind modeling 30
Figure 15. Weekly maximum, mean, and minimum hydropower generation from U.S. generators 34
Figure 16. U.S. generation in 2024 and 2050 in the NARIS core scenarios 37
Figure 17. U.S. generation capacity in 2024 and 2050 in the NARIS core scenarios 37
Figure 18. Fraction of generation coming from renewable generators in the United States 39
Figure 19. Normalized average aggregate EUE (ppm) by scenario and load multiplier for the United States 42
Figure 20. U.S. contribution of different technologies to energy and planning reserve in the Low Cost VG scenario 43
Figure 21. Energy generation in the Low Cost VG scenario in 2050 44
Figure 22. Summer planning reserve in the Low Cost VG scenario 45
Figure 23. Winter planning reserve in the Low Cost VG scenario 45
Figure 24. Contribution of renewable generators to summer planning reserve needs in the United States 46
Figure 25. Thermal generation utilization in Low Cost VG scenario in 2050 by interconnection 48
Figure 26. Thermal generation utilization in the U.S. Western Interconnection (Low Cost VG 2050) 48
Figure 27. Thermal generation utilization in the U.S. Eastern Interconnection (Low Cost VG 2050) 49
Figure 28. Thermal generation utilization in the Texas Interconnection (Low Cost VG 2050) 49
Figure 29 Added transmission capacity in the core scenarios (measured in GW of interface expansion) . 50
Figure 30. New transmission capacity in the core scenarios 51
Figure 31. Continent-wide net value of transmission expansion 53
Figure 32. Macrogrid design 54
Figure 33. Net United States/Canada trade in all scenarios (core scenarios colored) 55
Figure 34. Gross United States/Canada trade in all scenarios (with core scenarios colored) 55
Figure 35 Net U.S./Mexico trade in all scenarios (with core scenarios colored) 57
Figure 36 Gross U.S./Mexico trade in all scenarios (with core scenarios colored) 57
Figure 37. Maximum utilization of paths in the near-term (2024) PRAS adequacy model 58
Figure 38. Maximum utilization of paths in the Low Cost VG 2050 scenario in PRAS model 59
Figure 39. Histogram of total utilization of expansion lines (Low Cost VG 2050) 60
Figure 40. Net interchange between regions and their neighbors over the year (Low Cost VG 2050) 61
Figure 41. Gross interchange between regions and their neighbors over the year (Low Cost VG 2050) ... 62
Figure 42. Duration curve of flows along major U.S. interfaces in Low Cost VG 2050 63
Figure 43. U.S. Eastern Interconnection generation dispatch stack for early September (Low Cost VG 2050) 64
Figure 44. U.S. Western Interconnection generation dispatch stack for early September (Low Cost VG 2050) 65

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

Figure 45. Texas Interconnection generation dispatch stack for early September (LowCost VG 2050).... 65
Figure 46. U.S. curtailment duration curve.... 66
Figure 47. U.S. curtailment duration by hour (left) and month (right).... 67
Figure 48. U.S.-wide dispatch stack during a high-curtailment period.... 67
Figure 49. U.S. Western Interconnection hydropower and net load during a week with both high- and low-load days in September in the Low Cost VG 2050 scenario.... 68
Figure 50 U.S. Western Interconnection hydropower generation and net load during a week with high curtailment.... 69
Figure 51 Total U.S. generation versus total U.S. net load for the entire year.... 70
Figure 52. Daily cost reduction from hydropower flexibility.... 72
Figure 53. Change in 2050 capacity for core scenarios with lower-cost storage availability.... 73
Figure 54. U.S. CO_2 trajectory through 2050 in the core scenarios.... 74
Figure 55. Cumulative U.S. DPV deployment by cost scenario.... 75
Figure 56. Projected DPV installed capacity (Mid Cost Scenario) by county.... 77
Figure 57. Histograms of average retail cost of electricity ($/kWh) across United States by sector.... 78
Figure 58. DPV payback periods by year across sectors and scenarios.... 79
Figure 59. Total U.S. system costs for the core scenarios.... 80
Figure 60. Load growth due to additional electrification in the Electrification scenario.... 81
Figure 61. Electrification by state in 2050.... 82
Figure 62. Generation capacity difference in 2050 (left) and total new transmission builds (right) between CO_2 Constrained and Electrification scenarios.... 83

List of Tables

Table 1. Key Assumptions in the NARIS Core Scenarios through 2050.... 5
Table 2. Key Assumptions in All Scenarios through 2050.... 8
Table 3. Data Sources for All Three Countries in the Core Scenarios in ReEDS.... 14
Table 4. Data Sources for dGen.... 20
Table 5. Select Thermal Plant Assumptions.... 22
Table 6. Hydropower Assumptions.... 33
Table 7. U.S. Generation Capacity (GW) in 2024 and 2050 in the NARIS Core Scenarios.... 38
Table 8. EUE by Scenario and Meteorological Year for the United States, Compared to NERC LTRA.... 40
Table 9. Loss of Load Hours (LOLH) by Scenario, Compared to NERC LTRA.... 41
Table 10. Benefits of Hydropower Flexibility.... 71
Table 11. Impacts of Different Water Conditions.... 72
Table 12. Cumulative Adoption (GW) in 2050 by Region for Cost and Policy Sensitivities.... 76
Table 13. Continent-Wide Cost Impacts of Forecast Quality Used During Unit Commitment.... 84

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1 Introduction

The North American Renewable Integration Study (NARIS) is the first detailed power system integration study for the entire North American continent. NARIS aims to inform grid planners, operators, policymakers, and other stakeholders about the potential opportunities for system integration of large amounts of wind, solar, and hydropower to create a low-carbon grid in the future. The NARIS project began in 2016. This report describes a U.S. perspective in coordination with the U.S. Department of Energy, and a companion report describes a Canadian perspective in coordination with Natural Resources Canada.

The North American electric power grids are evolving toward higher contributions of variable generation (VG) resources (i.e., wind and solar) for several reasons, including lower costs and lower emissions. NARIS analyzes the entire North American continent, which is composed of five asynchronous interconnections that overlap the three countries. The analysis and conclusions of the study can help guide stakeholders to understand how the components of the power system can help work together to create a reliable, cost-effective, low-carbon grid in North America. This includes understanding the benefits of different technologies and operating practices to the future system.

The key analysis goals of NARIS were to evaluate a set of possible pathways for North American grid evolution through 2050 and to leverage production cost and Monte Carlo modeling tools to understand key questions about grid flexibility and resource adequacy.

NARIS extends and complements grid integration studies from the past, including the Pan Canadian Wind Integration Study (GE Energy Consulting 2016), Western Wind and Solar Integration Study (GE Energy 2010), and Eastern Renewable Generation Integration Study (Bloom et al. 2016). However, there are a few key differences between NARIS and most of these large, stakeholder-driven studies:

- NARIS studies all the grid-connected portions of Canada, the United States, and Mexico and applies consistent methods and data throughout. This includes the Eastern Interconnection, the Western Interconnection, the Texas Interconnection, the Quebec Interconnection, and the Sistema Eléctrico Nacional (Mexico).
- Partly because of its longer study horizon, NARIS studies higher deployment of renewable generation, especially VG resources such as wind and solar photovoltaics, throughout North America.
- NARIS optimizes the entire generation fleet and transmission infrastructure evolution through 2050, which makes each scenario specifically designed to key assumptions (Section 1.2). Many previous integration studies started with a planned system and added wind and solar to that system, without additional retirements or changes to the rest of the generating fleet.

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Some of the key accomplishments of NARIS include:

- Analysis
    - Performed the most comprehensive long-term analysis of power system evolution to date on the North American grid using models and data sets described in Section 2
    - Analyzed the feasibility and adequacy of high-renewable scenarios
    - Analyzed the value of technologies, including transmission, hydropower flexibility, and storage in the future power system
- Tools and Methods
    - Created continental capacity expansion planning tool (Regional Energy Deployment System Model, or ReEDS) based on expansion of the existing U.S. tool. The ReEDS model and data for the United States is open-sourced, with extensibility for Canada and Mexico pending public data. Aggregated results from the ReEDS modeling in NARIS are available on the NARIS website.[1]
    - Created open-sourced the Probabilistic Resource Adequacy Suite (PRAS)[2] modeling framework to assess multiregional system reliability metrics.
    - Improved methods for representing resource adequacy in capacity expansion models to produce reliable scenarios. This method has been open-sourced as part of ReEDS.
    - Created open-sourced, consistent, continent-wide wind resource data with 5-minute time resolution representing 2007–2014 (expanding the existing U.S. data set for wind). Solar 5-minute data were downscaled from existing the 30-minute National Solar Radiation Database data set.[3]
    - Created 5-minute resolution data sets for wind power, solar power, and load for a variety of scenarios
    - Created the open-source Renewable Energy Potential Model (reV)[4] model for geospatial analysis and data preparation for consistent use between modeling platforms.
    - Created dGen (Distributed Generation Market Demand)[5] distributed photovoltaics (DPV) adoption models for Canada and Mexico by extending the existing U.S.

[1] "North American Renewable Integration Study," NREL, https://www.nrel.gov/analysis/naris.html.
[2] "Probabilistic Resource Adequacy Suite," GitHub, https://github.com/NREL/PRAS.
[3] Data are available at "NREL Wind Integration National Dataset," Amazon Web Services, https://registry.opendata.aws/nrel-pds-wtk/. Usage examples are available at "NREL Highly Scalable Data Service (HSDS) Examples," GitHub, https://github.com/nrel/hsds-examples. Solar data are available at "NSRDB: National Solar Radiation Database," NREL, https://nsrdb.nrel.gov/.
[4] "reV: The Renewable Energy Potential Model," NREL, https://www.nrel.gov/gis/renewable-energy-potential.html.
[5] "Distributed Generation Market Demand," NREL, https://www.nrel.gov/analysis/dgen/.

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model, with as much data consistency with the U.S. model as the data sources allow

- Refined hydropower flexibility assumptions in the models, enabling sensitivities to understand the value of flexibility.

The primary technologies considered in NARIS were wind, solar PV, and hydropower, with a focus on the flexibility benefits of existing hydropower. Transmission and storage were examined with a variety of modeling runs. Other renewable generation technologies that might contribute to the system in 2050 but were not a key focus in the study include concentrating solar power, geothermal, and biomass; for these resources (and also nuclear generation), existing assumptions in the models and data sets were used (for costs and performance of new and existing assets), but no additional scenario analysis was done to understand the potential pathways for these resources.

The methods and analysis for this study were guided by the NARIS Technical Review Committee, which helped ensure the methods and data were rigorous, and that we were addressing important questions.

1.1 Motivation

North America has abundant and diverse energy resources, including renewable resources. For example, Figure 1 (page 4) shows wind and solar resource, and Figure 2 (page 5) shows hydropower installations and transmission infrastructure. However, with significant growth in wind and solar generation in the past decade, the grid is becoming more meteorologically dependent than ever before. NARIS endeavors to examine the challenges and opportunities associated with this increased dependence.

Existing and new generation technologies like reservoir, run-of-river, and pumped-storage hydropower; battery storage; and thermal generation all play a role in the future grid. NARIS' findings, like those of much previous work, verify that transmission infrastructure with coordinated operation can help North America take advantage of the diversity of resources to produce affordable and reliable energy. NARIS aims to analyze some of the ways these technologies can work together in a variety of future scenarios.

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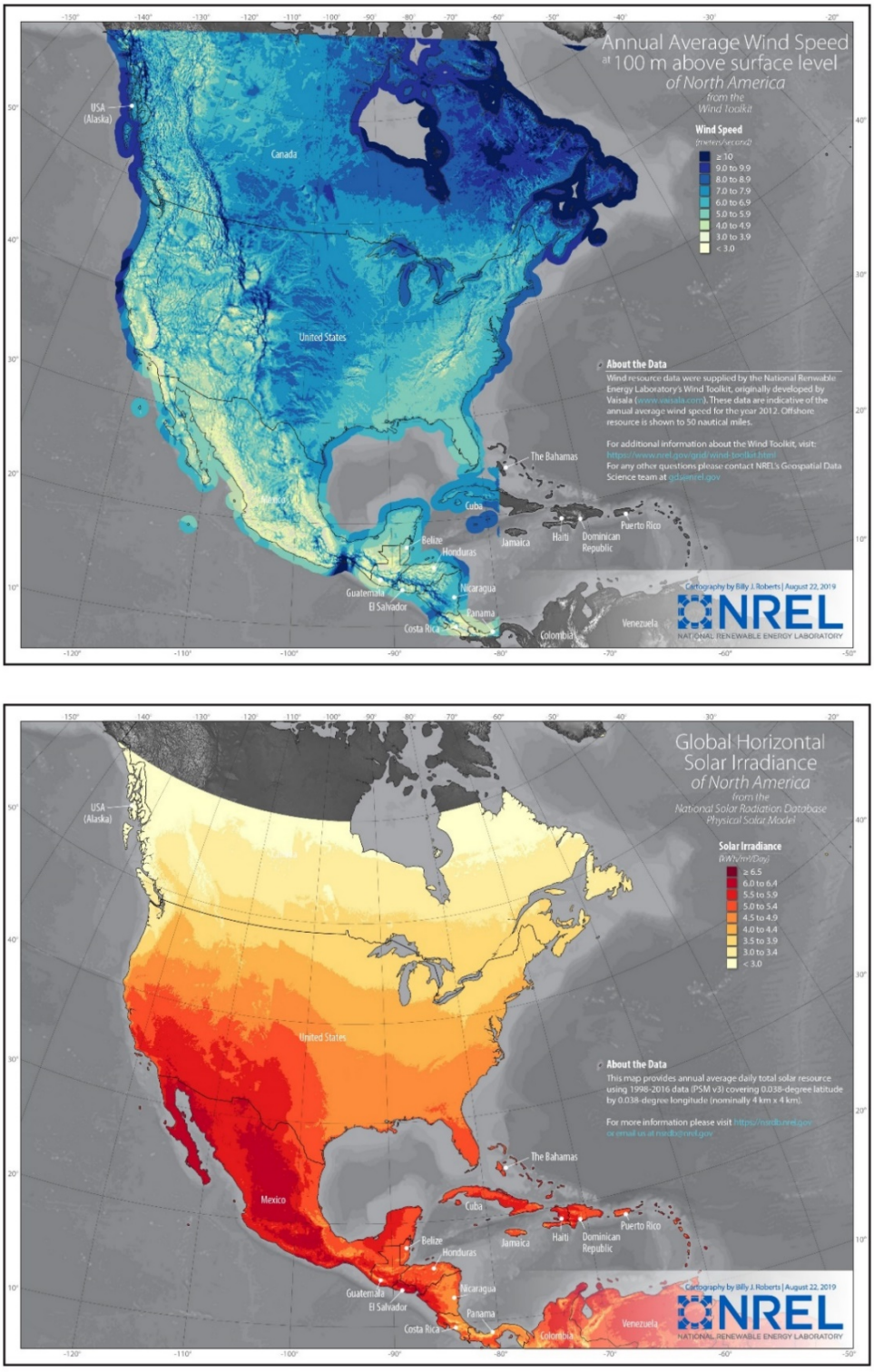

Figure 1. North American wind (top) and solar (bottom) resource

North America has some of the best wind and solar resource in the world, and all regions have excellent wind or solar resources nearby. Many regions have good resource for both wind and solar. These maps show the resource potential; siting and other constraints will limit deployment in some areas, and other inputs like temperature and air density will impact the translation of the resource to power.

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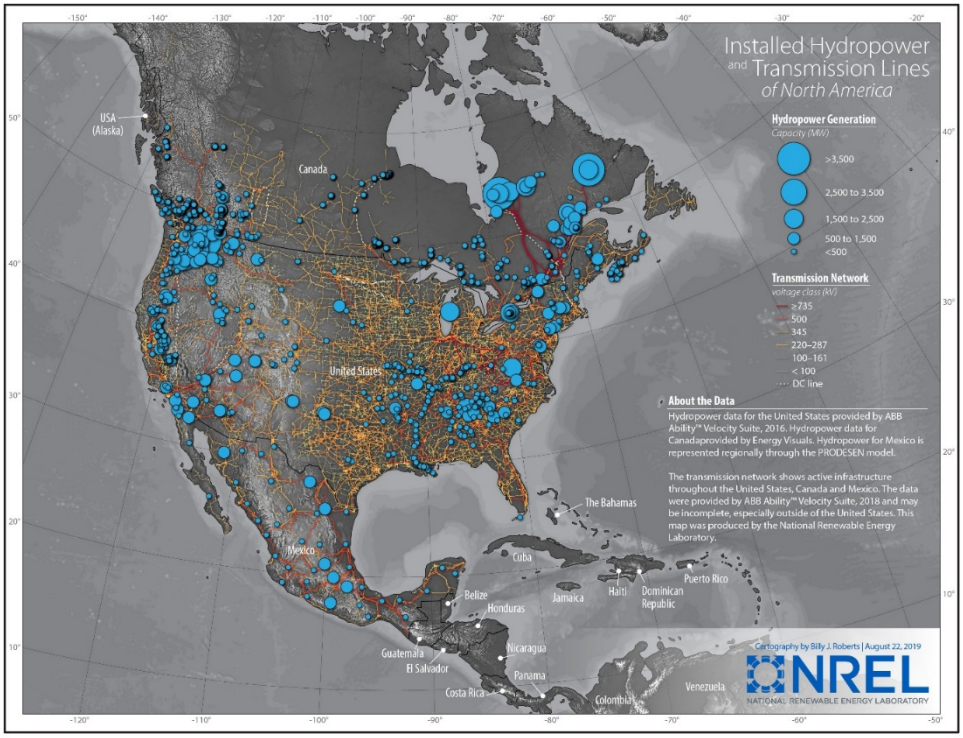

Figure 2. Installed hydropower and transmission lines of North America

North America has hydropower resource concentrated in several regions throughout the continent. It is evident that many high-voltage transmission lines have been built to connect hydropower with load centers (e.g., the West Coast and East Coast). Transmission helps enable geographic diversity among all generating resources and load, and hydropower generation can also contribute to the flexibility. Although the NARIS scenarios do not model extensive hydropower expansion, the value provided by hydropower is examined in Section 3.4

1.2 Scenario Overview

The NARIS scenarios were designed to examine a range of future possible grid evolution; many of them share assumptions with the annual National Renewable Energy Laboratory (NREL) Standard Scenarios[6] work. The four "core scenarios" shown in Table 1 indicate four potential pathways of North American grid evolution through 2050. Figure 3 shows the key assumptions for the core scenarios; detailed assumptions are available in Section 2.

Table 1. Key Assumptions in the NARIS Core Scenarios through 2050

Scenario	Key Assumptions
Business as Usual (BAU)	The North American grid continues to evolve with expected trajectories for all technology costs, and there are no major changes to carbon legislation across the continent. The scenario includes only state-based requirements as of October 2018 in the United States.
Low-Cost Variable Generation (Low-Cost VG)	VG, including wind and solar, follows a low-cost trajectory based on NREL's 2018 Annual Technology Baseline (ATB).[b] Otherwise, the scenario is the same as the BAU scenario.

[6] "Standard Scenarios ," NREL, https://www.nrel.gov/analysis/standard-scenarios.html.

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Scenario	Key Assumptions
Carbon Constrained (CO_2 Constrained)	Carbon emissions from the electricity sector are reduced throughout North America, including an 80% reduction from 2005 levels in the United States and Mexico and a 92% reduction in Canada, also from 2005 levels.[a] Otherwise, the scenario is the same as the BAU scenario.
Electrification	New end-use energy demands, including heating and transportation are electrified. And 2050 loads are nearly double the 2020 loads. Otherwise, the scenario is the same as Carbon Constrained scenario.

[a] The starting points for the carbon assumptions, especially in the Carbon Constrained scenarios, were the Paris Agreement Mid-Century Strategy documents in all three countries (Government of Canada 2016; SEMARNAT-INECC 2016; White House 2016), with the BAU being based on legislation in Canada

[b] "Annual Technology Baseline: 2018 ATB," NREL, https://atb.nrel.gov/electricity/2018/.

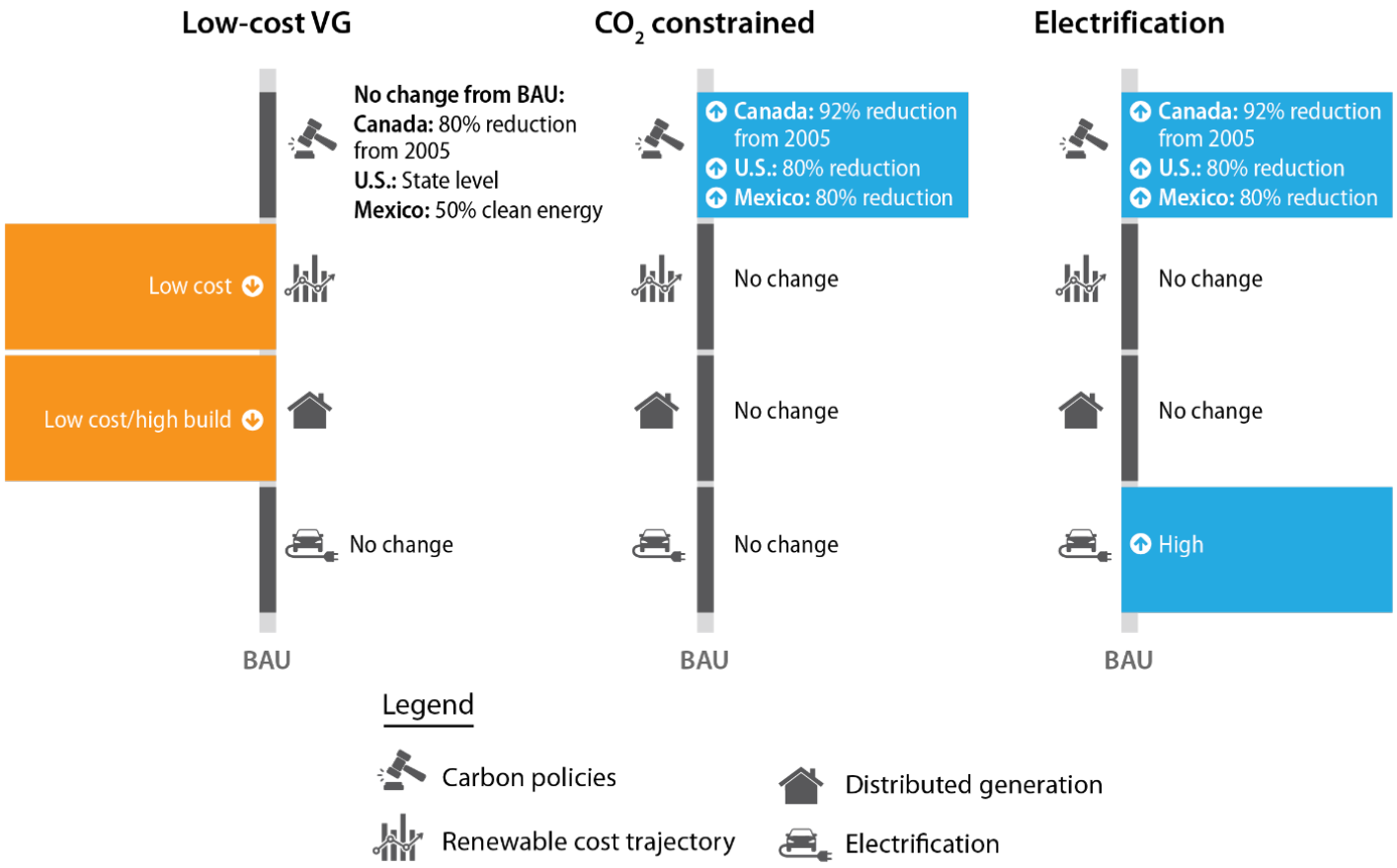

Figure 3. Comparison of core scenarios in NARIS

All changes noted above are in comparison with the BAU.

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We also studied a variety of sensitivities to these core scenarios, typically by varying one assumption at a time. These changes include gas prices, transmission build assumptions, storage costs, and other variables. Each sensitivity describes the entire evolution of the grid through 2050 and is referred to as a "scenario" throughout the report. This report focuses primarily on the core scenarios, especially the BAU and Low-Cost VG. The sensitivities help us understand uncertainty and help us quantify the impacts of key assumptions or technologies. Where the additional scenarios are important for conclusions, they are described and presented in the appropriate section. Detailed results for all scenarios are available are available on the NARIS website.[7]

[7] "North American Renewable Integration Study," NREL, https://www.nrel.gov/analysis/naris.html.

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Table 2. Key Assumptions in All Scenarios through 2050[a]

Scenario (+ Sensitivity Tag)	Canada Carbon Policy[b]	U.S. Carbon Policy[b]	Mexico Carbon Policy[b]	Cost Trajectories	Transmission[c]	Retirements[d]	Electrification[e]	Gas Price
Business as Usual (BAU)	**80% Reduction**	**State-Level**	**50% clean**	**BAU**	**Coordinated**	**BAU**	**BAU**	**BAU**
BAU Early Retire	—	—	—	—	—	Early	—	—
BAU High Cost Gas	—	—	—	—	—	—	—	High
BAU Low Cost Gas	—	—	—	—	—	—	—	Low
BAU Low Cost Storage	—	—	—	Low-cost storage	—	—	—	—
BAU Macro Grid	—	—	—	—	+ Macrogrid	—	—	—
BAU No Cross-Border Expansion	—	—	—	—	+ No new cross-border lines allowed	—	—	—
BAU No Cross-Border Expansion Uncoordinated	—	—	—	—	Uncoordinated, no new cross-border lines	—	—	—
BAU Uncoordinated	—	—	—	—	Uncoordinated	—	—	—
Low-Cost Variable Generation (VG)	**80% Reduction**	**State-Level**	**50% Clean Energy**	**Low-Cost RE**	**Coordinated**	**BAU**	**BAU**	**BAU**
Low Cost VG Early Retire	—	—	—	—	—	Early	—	—
Low Cost VG High Cost Gas	—	—	—	—	—	—	—	High
Low Cost VG Low Cost Gas	—	—	—	—	—	—	—	Low
Low Cost VG and Storage	—	—	—	Low-cost storage + VG	—	—	—	—
Low Cost VG Macro Grid	—	—	—	—	+ Macrogrid	—	—	—
Low Cost VG No Cross-Border Expansion	—	—	—	—	+ No new cross-border lines allowed	—	—	—
Low Cost VG No Cross-Border Expansion Uncoordinated	—	—	—	—	Uncoordinated, no new cross-border lines	–	—	—
Low Cost VG Uncoordinated	—	—	—	—	Uncoordinated	—	—	—
Carbon Constrained	**92% Reduction**	**80% Reduction**	**80% Reduction**	**BAU**	**Coordinated**	**BAU**	**BAU**	**BAU**
CO2 Constrained Early Retire	—	—	—	—	—	Early	—	—
CO2 Constrained High Cost Gas	—	—	—	—	—	—	—	High
CO2 Constrained Low Cost Gas	—	—	—	—	—	—	—	Low
CO2 Constrained Low Cost Storage	—	—	—	Low-cost storage	—	—	—	—
CO2 Constrained Macro Grid	—	—	—	—	+ Macrogrid	—	—	—
CO2 Constrained No Cross-Border Expansion	—	—	—	—	+ No new cross-border lines allowed	—	—	—
CO2 Constrained No Cross-Border Expansion Uncoordinated	—	—	—	—	Uncoordinated, no new cross-border lines	—	—	—
CO2 Constrained Uncoordinated	—	—	—	—	Uncoordinated	—	—	—
CO2 Constrained Low Cost VG	—	—	—	Low-cost VG	—	—	—	—
CO2 Constrained Low Cost VG High Gas	—	—	—	Low-cost VG	—	—	—	High
CO2 Constrained Low Cost VG and Low Cost Storage	—	—	—	Low-cost VG and storage	—	—	—	—
Electrification	**92% Reduction**	**80% Reduction**	**80% Reduction**	**BAU**	**Coordinated**	**BAU**	**High**	**BAU**
Electrification Early Retire	—	—	—	—	—	Early	—	—
Electrification High Cost Gas	—	—	—	—	—	—	—	High
Electrification Low Cost Gas	—	—	—	—	—	—	—	Low
Electrification and Storage	—	—	—	Low-cost storage	—	—	—	—
Electrification Macro Grid	—	—	—	—	+ Macrogrid	—	—	—
Electrification No Cross-Border Expansion	—	—	—	—	+ No new cross-border lines allowed	—	—	—
Electrification No Cross-Border Expansion Uncoordinated	—	—	—	—	Uncoordinated, no new cross-border lines	—	—	—
Electrification Uncoordinated	—	—	—	—	Uncoordinated	—	—	—
Electrification Low Cost VG	—	—	—	Low-cost VG	—	—	—	—
Electrification Low Cost VG High Gas	—	—	—	Low-cost VG	—	—	—	High
Electrification Low Cost VG and Low Cost Storage	—	—	—	Low-cost VG and storage	—	—	—	—

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The table does not include hydropower sensitivities (flexibility, wet/dry, or Canadian supply sensitivities), described later in the report

[a] — Indicates no change from core case for the scenario

[b] Carbon

- Canada: Assumes BAU is an 80% CO_2 reduction and Carbon Constrained is a 92% reduction, which is more in line with Mid-Century Strategy, and is 80% economy-wide
- United States: Assumes BAU is state-level policies only and Carbon Constrained is a 80% reduction (in line with Mid-Century Strategy)
- Mexico: Assumes BAU is 50% clean energy standard and Carbon Constrained is a 80% reduction

[c] Transmission

- Coordinated: The model builds and operates transmission in an optimal way.
- Uncoordinated: The model sees hurdle rates (cost to flow power) between regions and only builds lines that have a benefit-cost ratio above 3.
- No cross-border: The model runs the same as coordinated but without any new cross-border transmission allowed (to help understand the benefit of new cross-border lines).
- Macrogrid: The model runs as coordinated, with an HVDC (high-voltage direct current) macrogrid. Some potential benefits of this grid might not be well captured in standard modeling frameworks. The macrogrid is based on the grid for the U.S. Interconnections Seam study, with an extension into Canada.

[d] Retirements

- This scenario represents potential concerns for early thermal unit retirement.
- Coal: In the Early Retirements scenario, coal is assumed to retire early based on whether the ReEDS model continues to operate with more than 75% capacity factor. This could be driven by lack of cost recovery or carbon or other pollutant policies. In BAU, only announced retirements are included.
- Nuclear: In the Early Retirements scenario, all nuclear is assumed to not be relicensed (but operates until relicensing), based on ongoing retirement concerns. In the BAU assumption, 50% of nuclear is relicensed and still operating in 2050 (based on commission date)

[e] Electrification and Load Growth

- Canada: BAU (nonelectrification) cases assume 2050 load of 780 terawatt-hours (TWh) (based on Canada's National Energy Board extrapolated). Electrification cases assume 1,070 TWh (based on EnergyPATHWAYS modeling for NARIS). 2016 load is 600 TWh.
- United States: BAU (nonelectrification) cases assume 2050 load of 5,100 TWh (based on U.S. Energy Information Administration [EIA] extrapolated). Electrification cases assume 7,100 TWh (based on NREL's Electrification Futures Study). 2016 load is 3,950 TWh.
- Mexico: Because the Programa de Desarrollo del Sistema Eléctrico Nacional (PRODESEN) and the Mid-Century Strategy have similar assumptions for load growth, both scenarios are identical in load. 2016 load is 310 TWh. 2050 load is 790 TWh.
- In current runs, no hourly profile changes are considered for electrification, except optimal vehicle charging. Reference the Electrification Futures Study[8] for more work on this topic.

[8] "Electrification Futures Study," NREL, https://www.nrel.gov/analysis/electrification-futures.html.

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1.3 Assumptions and Limitations

This section describes the key assumptions and limitations of NARIS so stakeholders can understand the context for interpreting the study results.

- NARIS is not a forecast or official plan for any given region or state. The scenarios were produced through specific optimization methods, so infrastructure decisions may differ from actual decisions organizations choose to make. The study analyzes a suite of scenarios to understand ways the grid could evolve and operate to help inform planners. In many cases, the optimization is shallow and there are alternative infrastructure builds with similar costs.
- This study considers enacted legislation with binding targets for renewable or clean energy portfolios that cover electricity generation at the federal or state/province levels by October 2018; it does not attempt to extrapolate local or corporate targets, or to understand how they could impact infrastructure builds. For the United States, federal policies include tax credits but no renewable portfolio rules or carbon limits for the BAU scenarios.
- More study is needed to understand dynamic concerns, including frequency stability. This study does not perform any AC or dynamic power flow modeling.
- Operational practices will continue to change between today and 2050, including the way balancing authorities interact with each other. Aside from several scenarios, this study assumes regions can efficiently trade electricity or build infrastructure if it is optimal.
- NARIS is not a detailed analysis of electricity markets. Specific market rules and participant behavior will impact the evolution and operation of the grid; the study is based mostly on optimization models and assumes overall cost-optimal resources will be developed and operated (as described in Section 2.1). The study does not attempt to determine whether generation resources will receive sufficient revenue in existing or future market structures.
- The study does not consider the impact of climate change on demand patterns, wind, solar, hydropower, or thermal generation.
- NARIS assumes decision-making at the retail (consumer adoption of rooftop PV) and wholesale (utility-scale generation and transmission) is made differently, and subject to different sets of policy assumptions. See Sections 2.1.1 and 2.1.2 for details.
- No policy recommendations are made in this report.
- All costs are in 2018 USD.

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2 Data and Methods

This section provides an overview of the data, models, and methods used in NARIS; many of the models and data are documented elsewhere and are open-sourced.

2.1 Methods and Models

Figure 4 provides an overview of the modeling process used in the NARIS. Four primary modeling types underpin the analysis:

- Distributed generation market adoption: The NREL dGen model is an agent-based consumer adoption model that projects different pathways of distributed PV deployment for the residential, commercial, and industrial sectors.
- Generation and transmission capacity expansion: The NREL ReEDS model co-optimizes the build-out of generation and transmission infrastructure, subject to the assumptions in each scenario.
- Production cost (unit commitment and dispatch): The Energy Exemplar PLEXOS model simulates the operation of the power system at hourly and 5-minute time-scales.
- Reliability (resource adequacy) model: The NREL PRAS model simulates simplified system operation for every hour for 7 years of meteorological conditions (affecting wind, solar, and load profiles), and thousands of random draws of outages of thermal generators.

The same data were used throughout NARIS for different temporal and geographic scales. The distributed generation and capacity expansion models were used to explore the uncertainty in power system evolution, and then the production cost and resource adequacy models were used to study a few key scenarios in detail.

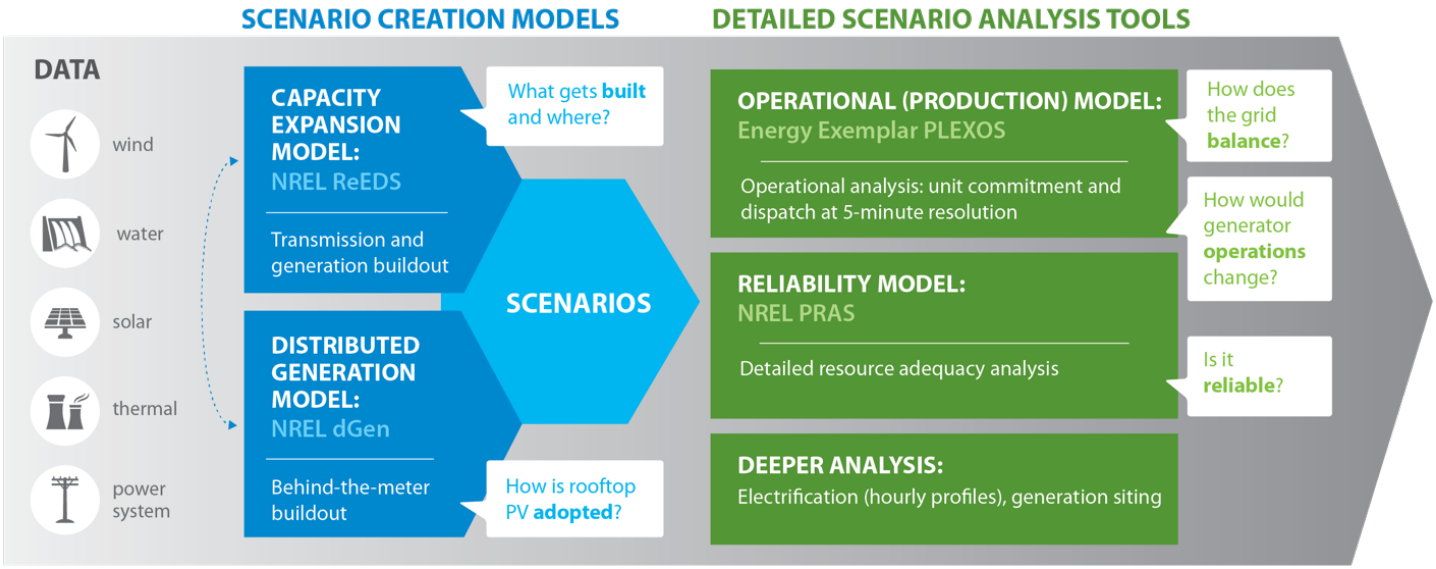

Figure 4. Modeling flow

This diagram shows the modeling flow of the key models used in NARIS, including the transmission-level capacity expansion (NREL ReEDS), distributed PV adoption (NREL dGen), production cost grid simulation (Energy Exemplar PLEXOS), and resource adequacy (NREL PRAS). The reV geospatial tool helped keep the data consistent at all modeling scales.

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2.1.1 Capacity Expansion Modeling: ReEDS

The NREL Regional Energy Deployment System (ReEDS) model is an electricity sector capacity expansion model representing the North American power system. The model, through least cost optimization, evaluates the location and timing generation and transmission investments throughout the system. For a detailed explanation of the model, see Cohen et al. (2019).

ReEDS represents the diverse spectrum of generation, storage, and transmission technologies relevant to power system decision makers. As part of the modeling process ReEDS contains an endogenous representation of power system needs. These include operational requirements in electric power including, balancing demand, renewable resource availability, generation technology limits. System reliability is ensured by including planning reserve and spinning reserve requirements. Planning reserves can be served by all types of resources; capacity credits for wind and solar resources are estimated in each model region and year by estimating the contribution of these resources in periods of high load and low wind and solar generation. These estimates are done using hourly load, wind, and solar data (see Section 2.2) using 2012 meteorology. Other years are tested in the PRAS modeling (see Section 2.1.4). U.S. federal and state policies are explicitly represented, including renewable production and investment tax credits and state based clean energy policies like California's SB-100.

ReEDS selects a least-cost mix of operation and investment decisions while satisfying all modeled requirements described in this section. Model simulations occur in 2-year periods starting in 2010 (build decisions through 2020 are fixed to historical builds) and ending in 2050. In historical years, investment decisions are restricted to match the location and timing transmission and generation developments that occurred. Within each simulation, a year of operations decisions are modeled with a reduced order dispatch, using 17 representative time-slices to represent year. For each of the four seasons, time blocks of morning, afternoon, evening, and overnight hours are aggregated based on time of day in local time to form time-slices. An additional 17th super-peak time-slice is created from the top 40 summer afternoon (1 pm–5 pm) hours. Reducing the operational dispatch from 8,760 hours to 17 representative time-slices preserves seasonal and diurnal variability within the model while reducing the computational burden. Outside the simulation, more granular hourly data sets are also used by the model to estimate curtailments and the capacity value provided by variable renewable technologies.

The representation of the United States is divided into 134 balancing areas, and 356 wind and solar resource regions (Figure 5). Alaska, Hawaii, and U.S. territories are not included as part ReEDS representation of the United States; nor are nongrid connected generation and load. The U.S. aggregated transmission network is connected by 418 transmission lines (that represent interfaces between regions) among three asynchronous regions.

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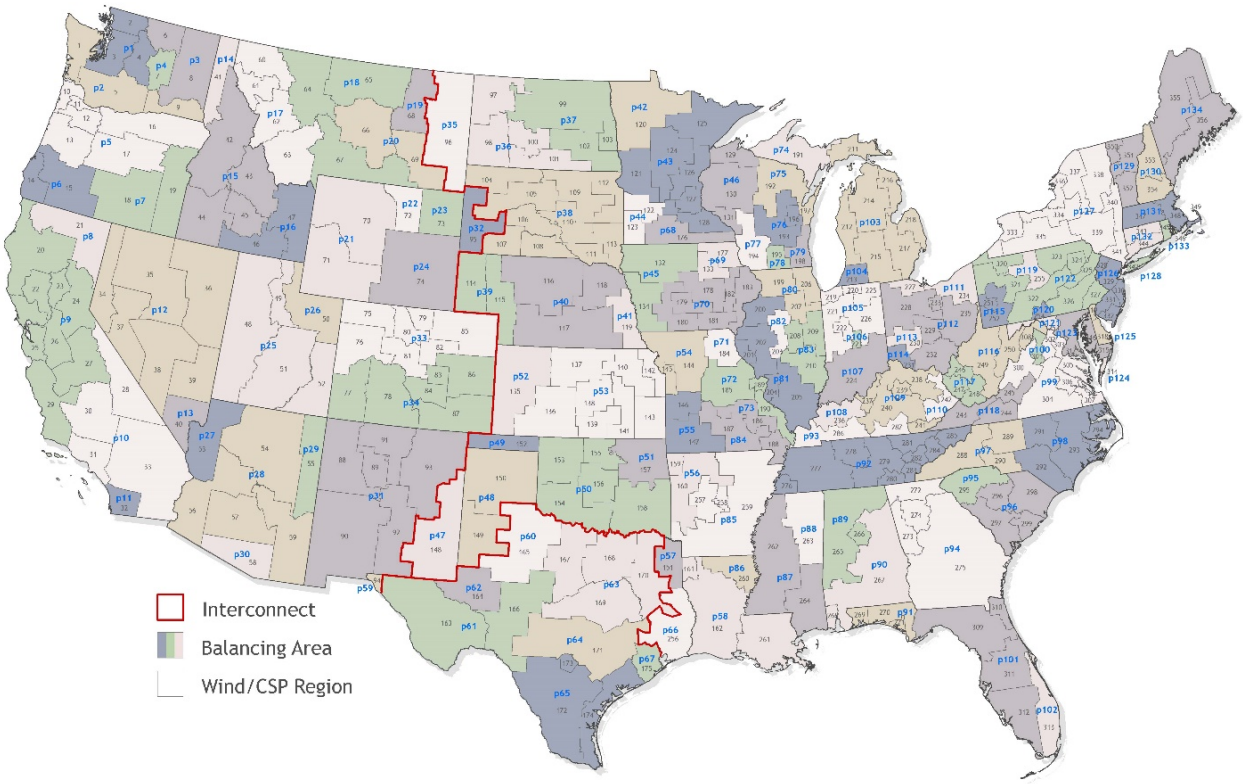

Figure 5. ReEDS U.S. zonal representation

The resulting outputs of a ReEDS solution contain detailed information about the evolution of the power system relevant to decision makers. The model outputs extends beyond the energy generated and capacity of plants and transmission interfaces within the United States. Examples of more-detailed operations outputs include the capacity value of wind and solar and the distribution of reserves by region and technology. ReEDS also outputs detailed system cost information, which helps to understand the implications of different regulatory and technological futures. The results also include a diverse range of environmental outputs, including CO_2 emissions. Shadow prices are used to understand economic questions, including why certain generation technologies are developed and prices ranging from competitive electricity prices to environmental constraints. Interregional and cross-border international transmission and power flows are also output. The ReEDS model was run on all scenarios described in Section 1.2; additional analysis beyond the ReEDS model was done for several key scenarios, as described later in the report.

Table 3 lists the data sources for all three countries in the core scenarios in ReEDS.

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Table 3. Data Sources for All Three Countries in the Core Scenarios in ReEDS

Category	Canada Assumption	Mexico Assumption	U.S. Assumption
Natural gas supply curve and regional consumption	Regional gas supply curves were derived from U.S. Energy Information (EIA) Annual Energy Outlook (AEO2018) (EIA 2018) price and consumption data. Supply curves were extended to include adjacent Canadian provinces by adjusting natural gas consumption based on consumption in Canada's National Energy Board (NEB) Canada's Energy Futures 2017 (NEB 2017)	Supply curve was derived from AEO2018 (EIA 2018) West South Central region, adjusted for projected gas consumption and prices in the Programa de Desarrollo del Sistema Eléctrico Nacional (PRODESEN 2018) (SENER 2018).	Supply curve was derived from AEO2018 (See Cohen et al. 2019.)
Coal prices	*Canada's Energy Futures 2017* (NEB 2017) (province-level)	PRODESEN 2018[a]	AEO2018
Electricity demand projections (see Section 3.5.4 for details on Electrification)	*Canada's Energy Futures 2017* (NEB 2017) Evolved Energy Research (Electrification scenario)	PRODESEN 2018 Evolved Energy Research (Electrification scenario)	AEO2018 Evolved Energy Research (Electrification scenario)
Hourly electricity demand (See Section 2.2.2 for details.)	Various provincial-level sources	PRODESEN 2018	Independent system operators (ISOs) and Federal Energy Regulatory Commission Form 714
Existing generation fleet	ABB Velocity Suite (ABB 2018) was mapped to ReEDS power control areas using spatial analysis.		
Announced retirements	Various provincial-level sources	ABB Velocity Suite (ABB 2018), AEO2018	PRODESEN 2018
Plant cost and performance	ABB Velocity Suite (ABB 2018); AEO2018		
Transmission costs	Distance per mile costs were estimated from the Eastern Interconnection Planning Collaborative Phase 2 Report (EIPC 2015). Transmission costs were $1,347–$2,333 per MW-mile depending on the line voltage. Spur lines connecting utility-scale solar and wind to the power system cost $3,667/MW-mile.		
Planned hydropower builds	*Canada's Energy Futures 2017* (NEB 2017) (province-level)	PRODESEN 2018	Hydropower Vision Report (DOE 2016), ABB Velocity Suite (ABB 2018)

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Category	Canada Assumption	Mexico Assumption	U.S. Assumption
Seasonal hydropower capacity factors	*Canada's Energy Futures 2017* (NEB 2017) (province-level)	PRODESEN 2018 fleetwide average	Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC) 2024 (West Only); National Hydropower Asset Assessment Program
Onshore wind resource supply curve	2-km x 2-km Wind Toolkit meteorological were processed using the Renewable Energy Potential model (reV) to generate cost and performance supply curves for wind. Generated data are available at the level of subpower control areas and are consistent with assumptions from the NREL Annual Technology Baseline (ATB).		
PV resource supply curve	4-km x 4-km National Solar Radiation Database solar irradiance data were processed using reV to generate cost and performance supply curves for utility-scale PV. Both utility scale (rural development) and distributed utility scale (urban development) were included with distinct resource costs consistent with the ATB.		
State renewable portfolio standards and clean energy standards	Province-level policies including the British Columbia carbon tax and New Brunswick, Nova Scotia, and Prince Edward Island renewable portfolio standards	N/A	State renewable portfolio standards and clean energy standards policies derived from regular ReEDS updates from the Database of State Incentives for Renewables
International trading rules for renewable energy certificates	N/A	N/A	State-specific trading rules from the Database of State Incentives for Renewables

Canada's Energy Future 2018 was not yet published by the National Energy Board when we finalized our assumptions and synchronized the model across the three countries. We did confirm that the key variables did not change significantly from 2017. Starting in 2019, the Canada Energy Regulator now publishes this report.

[a] PRODESEN, Programa de Desarrollo del Sistema Eléctrico Nacional, https://www.gob.mx/sener/acciones-y-programas/programa-de-desarrollo-del-sistema-electrico-nacional-33462, accessed 2018.

The cost trajectories used for these model runs are from NREL 2018 Annual Technology Baseline (ATB), as noted above. Figure 6 plots these cost trajectories in comparison to the 2020 ATB equivalent. Note that the NARIS BAU (2018 ATB Mid case) is closer to the 2020 ATB Conservative case costs for PV and wind, and it is slightly higher in 2050. The NARIS Low Cost trajectories are generally between the Advanced and Moderate trajectories for the 2020 ATB.

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These are levelized cost of electricity[9] (LCOE) comparisons based on moderate-quality resource for both wind and solar. Note that LCOE was not used for any purpose in the NARIS modeling; however, it is a useful metric for comparisons that depend on both the cost and the performance of technologies.

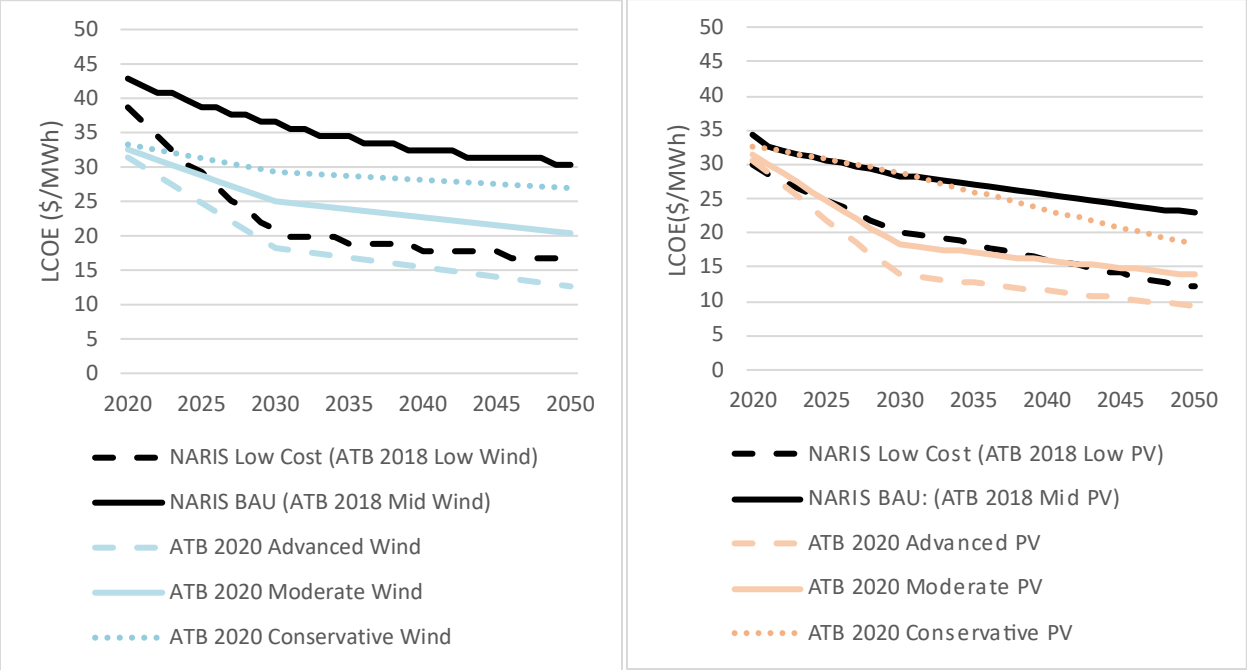

Figure 6. Cost comparison for wind (left) and solar PV (right) in the 2018 ATB and the 2020 ATB

All costs in report are 2018 USD.

2.1.2 Distributed Generation Modeling: dGen

Consumer adoption of distributed energy resources is made under a different framework than that of transmission-connected generation resources, and thus requires a separate approach. And three aspects of distributed energy resources are particularly germane to the distribution-connected versus transmission-connected discussion. First, distributed-connected resources are physically sited closer to load, leading to a different power flow than would otherwise be seen. Second, motivations for adoption are wholly different: transmission-connected resources are valued at the wholesale rate of electricity, and behind-the-meter resources are valued at the retail level. Moreover, consumers themselves have several drivers of adoption, including economic factors such as savings on electricity bills and a hedge against future rate changes, but also noneconomic ones such as environmental concerns and social influence from family and peers. Finally, a different set of policies is used to incentivize adoption of distributed energy resources than is used with utility-scale resources.

[9] LCOE is a "summary metric that combines the primary technology cost and performance parameters" to estimate the average cost per megawatt-hour of electricity based on cost and performance assumptions. See "Equations and Variables in ATB," NREL, http://atb.nrel.gov/electricity/2020/equations-variables.php.

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To reflect these differences in drivers of distributed energy resources capacity expansion, we used the Distributed Generation Market Demand (dGen) model to develop rooftop PV projections for the residential, commercial, and industrial sectors.[10] For NARIS, we developed new modules for Canada and Mexico. dGen is an agent-based model, representing bottom-up customer adoption. Agents are statistically representative based on sampling from distributions of customer attributes for each geography modeled. Agent sampling rates vary by country and sector, primarily because of data availability.

For the U.S. implementation of dGen, agents are sampled based on geography for the residential, commercial, and industrial sectors by county (n = 3108) in the United States. Thus, an "agent" represents a statistical cluster of multiple customers. For the U.S. version of dGen we used in NARIS, up to 30 agents were statistically sampled for each county (a total of 93,240 agents) based on representative distributions of features such as power consumption, rooftop size and angle.

Adoption projections in dGen are modeled through a four-step approach:

1. Generating agents (i.e., customers) and assigning them attributes based on a statistical sampling of their attributes (e.g., annual electricity consumption and roof size)
2. Applying technical and siting restrictions, such as resource quality, rooftop availability and quality for each agent
3. Analyzing cash flow to consider project costs, retail electricity rates, incentives, and net-billing/net metering policies; agents "select" PV systems that maximize their net present value
4. Projecting the future market share based on a generalized Bass diffusion model[11] to account for consumer behavior (Dong and Sigrin 2019). Market share is primarily determined by the system payback period, and the rate of diffusion is based on regressions of historical growth.

Technical potential is calculated in the first two steps by determining the number of developable roofs and the unshaded area. A building is "developable" if it meets shading, tilt, azimuth, and minimum area requirements (Gagnon et al. 2016); additionally, adoption is not considered for multifamily residential or renter-occupied residential buildings. In dGen for the United States, average roof sizes have been collected for each sector in each geography from Census data. Figure 7 displays the total technical potential of rooftop PV across Canada, Mexico, and the United States, ranked by capacity factor and sector. Technical potential includes all rooftop availability, subject to sting restrictions mentioned above.

[10] dGen can also model distributed wind, storage, and geothermal technologies, but we focused on distributed rooftop solar for NARIS.
[11] The Bass diffusion model determines how quickly consumers adopt consumer goods (in this case, PV).

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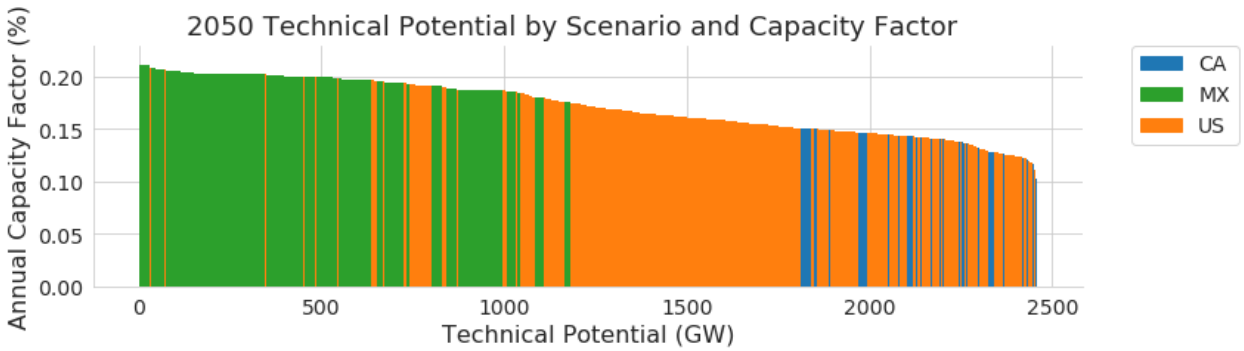

Figure 7. Distributed PV resource quality by country

This figure shows the technical potential of the rooftop resource in each country, ordered by capacity factor. Most of the best 600 GW of resource in North America are in Mexico. The United States has substantial capacity available above 15% capacity factors annually.

Within the United States, technical potential varies and is well distributed among sectors. Figure 8 displays cumulative technical potential by sector and capacity factor, with high capacity factors available in residential, commercial, and industrial sectors.

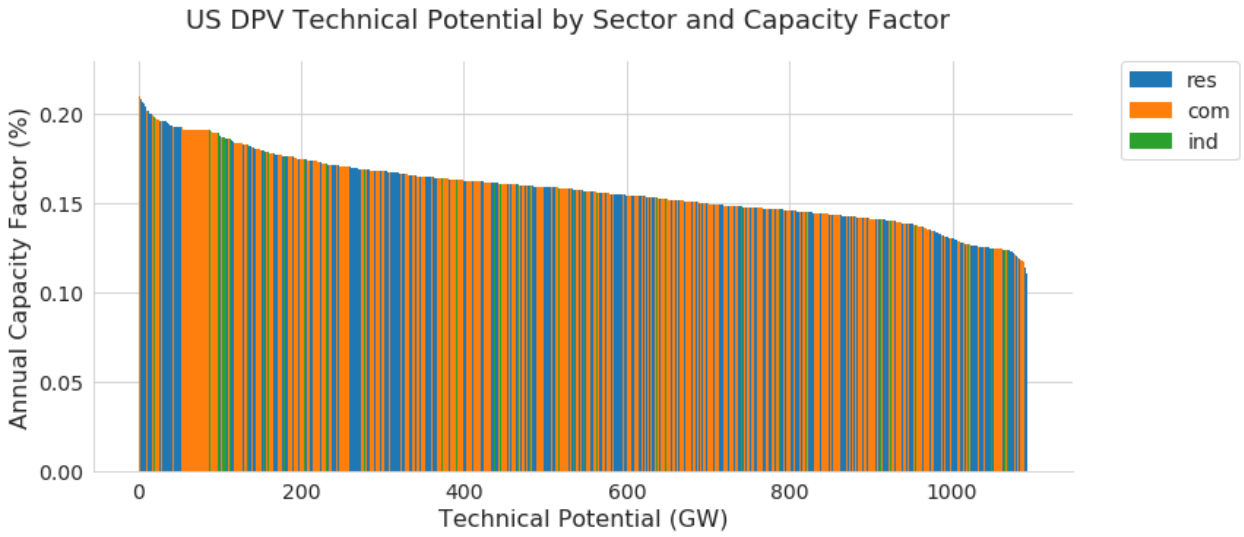

Figure 8. Distributed PV resource quality within the United States by sector

This figure shows the technical potential of the rooftop resource in each sector (residential, commercial, and industrial) within the United States, ordered by capacity factor. There is good resource in all sectors.

More than 1,000 GW of rooftop PV capacity is currently assessed to be technically feasible in the United States, but most of this is not yet economically feasible based on the NARIS modeling and assumptions. To determine the total achievable potential, dGen performs a detailed cashflow analysis for each agent to calculate the net present value of adopting solar. Various system sizes are tested to determine the economically optimal system size for a given agent based on their unique load consumption profile, solar resource availability profile, roof-size, retail rate, and financing terms. The optimal system size and net present value, once calculated, are translated into a payback period, which represents the number of years before electricity bill savings from the system's generation will offset system cost.

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Previous customer surveys have solicited consumer willingness-to-adopt solar at various payback periods. The results from these surveys are aggregated to determine the rooftop PV maximum market share (Sigrin and Drury 2014). Using historical adoption data and the calculated maximum-market share, a Bass diffusion model is used to project PV market share in each year. Payback period is used to determine the maximum (i.e., terminal) market share, and a regression on historical adoption trends is used to inform the rate of diffusion for each region-sector.

For NARIS, three scenarios were examined to assess agent sensitivity to changes in PV capital costs. The scenarios were harmonized by country in real terms based on the 2018 ATB for the Mid (Reference), Low, and Constant Costs scenarios. For reference, the 2050 Mid Costs value is $1,140/kW for residential-scale systems and $954/kW for nonresidential-scale systems. In the Low Costs, they are $560/kW and $517/kW respectively; in the Constant Costs scenario, they are $2,857/kW and $1,936/kW respectively. Operation and maintenance costs, which include inverter replacement are $3.6–$17/kW-year depending on scenario and sector.

We ran scenarios incorporating existing net energy metering (NEM) policies assuming all excess generation is credited at the retail electricity rate. In a state where the NEM has expired or has a mandated expiration date, exported generation was valued at the wholesale cost of electricity whereas the self-consumed energy was still valued at the retail rate of electricity (i.e., net billing). We also ran scenarios assuming NEM policies expire and net billing persists in all jurisdictions. Figure 9 shows the annual capital cost of PV per kilowatt used by dGen by sector and scenario. Note that this cost does not include taxes, incentives, or subsidies, which are determined by country.

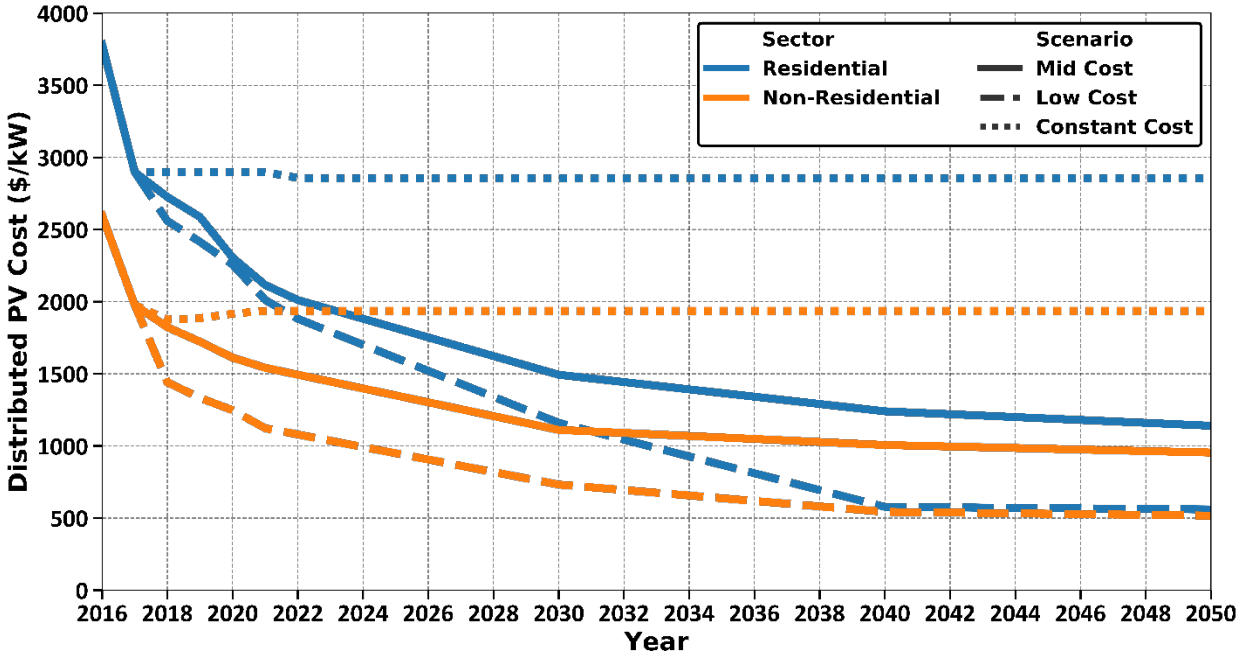

Figure 9. Cost trajectories for distributed PV

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Table 4 contains a list of the data sources used by dGen, summarized for each country. For the sake of comparability, and where possible, agents across the three countries were derived from common sources. For instance, each country models the residential and commercial sector (1) using common capital cost and financing assumptions and (2) excluding consideration of multitenant buildings.

Table 4. Data Sources for dGen

Category	Canadian Assumption	Mexico Assumption	U.S. Assumption
Model resolution (number of agents sampled)	Residential sector by census division (n = 293) Commercial-sector by province (n =10)	State-level by tariff-class (n = 1024)	10 agents per county, by sector (n = 93,240)
Building stock	Building counts by province and sector (2016 Census Program)	Counts determined by tariff classes for each state using SENER-provided data	Building characteristics sampled from Gagnon et al. (2016), Sigrin and Mooney 2018
Electrical load	See Section 2.2.2.	Annual consumption by state and tariff class Hourly load profiles based on control regions, using SENER-provided data	County-level load by sector (ABB 2013; EIA Residential Energy Consumption Survey and Commercial Buildings Energy Consumption Survey) Load profiles based on nearest weather station
Retail tariffs	Detailed calculation for current tariffs by utility using the OpenEI U.S. and International Utility Rate Database[a]		
Policies	Representation of current NEM policies and financial incentives; both assumed to expire based on statute		
Solar resource	Generation profile for 2012 meteorological year,[b] using for population-weighted regional midpoint, south-facing and tilted at latitude; building roof area based on U.S. sector-specific averages		Generation profile for 134 weather stations using TMY3 irradiance profiles.
Existing deployment	Annual installations and installed capacity by Province (2016)	System-level interconnection records (2016)	Annual installation by county and sector (2016)
Technology costs Financing	Based on 2018 ATB for residential-scale and commercial-scale PV systems		

[a] "Utility Rate Database," OpenEI, https://openei.org/wiki/Utility_Rate_Database, accessed 2018.
[b] NSRDB (National Solar Radiation Database), NREL, https://nsrdb.nrel.gov, accessed 2018.

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The results from the dGen model (based on consumer adoption) were considered in the ReEDS model capacity expansion to be generation available to the system to serve load within each zone. An iteration was done between the two models to create the generation inputs for ReEDS (from dGen), and then to reestimate electricity costs for dGen (based on ReEDS outputs). ReEDS was then rerun with the new distributed generation build-out. This was done for the Low-Cost VG scenario and the BAU.

2.1.3 Production Cost Modeling: PLEXOS

To understand the operation of future power systems, we used PLEXOS, a production cost model (PCM) developed by Energy Exemplar. The PCM simulates unit commitment and economic dispatch of the future grid infrastructure built by ReEDS. In this report, all production cost modeling results are from the Low Cost VG scenario in 2050. The results of the PCM run allow us to understand how transmission and generation operations change at hourly and subhourly levels while ensuring a reliable and efficient grid. The goal of modeling with 5-minute resolution 30 years in the future is to understand the overall feasibility and implications of operations—not to make a precise forecast of the future. Overall, the goal of the modeling is to demonstrate supply-demand balance using a unit commitment model, considering forecast error, with 5-minute dispatch resolution and a nodal transmission network.

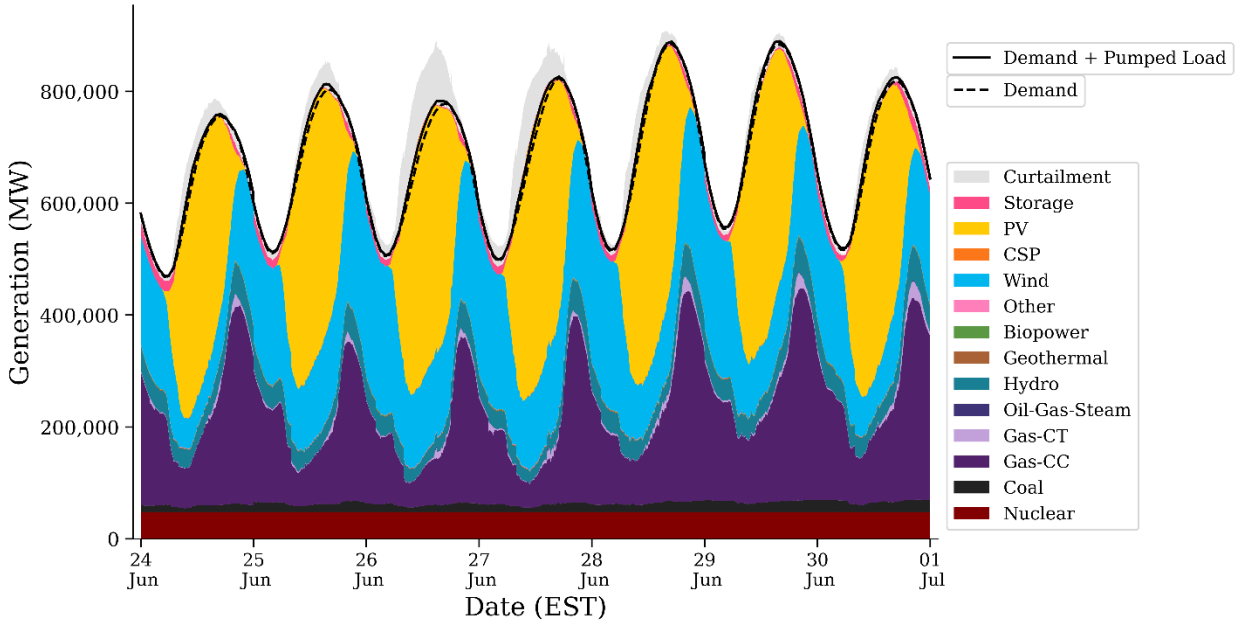

Figure 10. Sample PLEXOS output of U.S. generation dispatch stack for the week of June 24 (2050 Low Cost VG scenario)

Gas-CT: gas-combustion turbine; Gas-CC: gas-combined cycle

The production cost modeling for NARIS leverages a variety of assumptions and methods for modeling hydropower and thermal plants for the Western Interconnection (Brinkman et al. 2016) and the Eastern Interconnection (Bloom et al. 2016); assumptions about thermal unit start-up

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costs, outage rates, and hydropower conditions in NARIS are from these previous studies. Key differences are described below and in the description of the data (Section 2.2).

Installed capacity assumptions in the base model represent a 2024 power system. The expected installed thermal and hydropower generation capacity in 2024 came from several sources. For the Eastern Interconnection, generation capacity, location and type came from the 2026 Summer Peak Eastern Reliability Assessment Group Multiregional Modeling Working Group power flow case. For the Western Interconnection, capacity, location, and type came from the Western Electricity Coordinating Council's (WECC's) Transmission Expansion Planning Policy Committee (TEPPC) 2024 model with updates from the TEPPC 2026 case. Parameters for the Texas Interconnection came from the Electricity Reliability Council of Texas (ERCOT). Announced retirements and retirements modeled in ReEDS[12] were removed from the model.

Some thermal operating limits for existing generators deviated from Brinkman et al. (2016) and Bloom et al. (2016). The new operating limits were developed by analyzing historical data from the U.S. Environmental Protection Agency's Continuous Emissions Monitoring Systems. The data and approach for parameterizing for production cost modeling is described by Rossol et al. (2019). That analysis provided unit-specific full load heat rates, part load heat rate curves, and minimum generation levels for every generator with enough data in the Continuous Emissions Monitoring Systems data set. Previous work (Bloom et al. 2016) used generic heat rate curves and minimum stable levels for thermal plants.

Forced outage rates, maintenance outage rates, and mean repair times for nuclear, coal, gas, oil, and hydroelectric generators were taken from North American Electric Reliability Corporation (NERC) Generator Availability Data System data (GADS 2016). The Generator Availability Data System provides detailed information by unit maximum capacity for most major generator types, and these data were applied to the PCM. Other assumptions adopted from Bloom et al. (2016) are documented in Table 5.

Table 5. Select Thermal Plant Assumptions

Hydropower assumptions are in Section 2.2.3.

Category	Gas CT	Gas CC	Coal	Nuclear
Minimum uptime (hours)	0	6	24	N/A
Minimum downtime (hours)	0	8	12	N/A
Ramp rate (% of maximum capacity per minute)	8	5	2	N/A
Start-up cost ($/MW of maximum capacity)	69	79	129	0
Variable operation and maintenance cost ($/MWh)	0.6	1	2.8	2.8
Annual outage rates (sum of forced and maintenance outages) (% of year)	5.69%	4.69%	7.00%	3.41%

[12] ReEDS retirements are based on both announced retirements and modeled retirements. Modeled retirements are age-based (with thermal unit lifetimes of 55–75 years) or utilization-based (for coal plants under 40% annual capacity factor). See Eurek et al. (2016) for details.

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For the base PCM transmission topology, NARIS relied on nodal transmission models developed for the Eastern Interconnection and the Western Interconnection under the guidance of NERC. Power flow and dynamic base case models in the Eastern Interconnection (plus Quebec) are released by the Eastern Reliability Assessment Group Multiregional Modeling Working Group; we adopted the 2026 summer case as our base set of assumptions for the Eastern Interconnection. Line limits for the Eastern Interconnection were enforced for those lines included in the NERC Book of Flowgates. The Western Interconnection topology was originally created by the WECC TEPPC, which also provides the lines that make up the WECC Paths and define the limit to the flow along those paths. The topology for the Texas Interconnection comes from ERCOT. The lines connecting the ERCOT zones were enforced as interface constraints. The zonal representation from the Programa de Desarrollo del Sistema Eléctrico Nacional (PRODESEN) was used for the Mexican portion of the model.

Figure 11 shows the steps involved in a detailed PCM study. These steps are followed to simulate how a system operator might commit and dispatch a given system as forecasts of wind and solar availability and load are updated throughout the day. For NARIS, we did not perform the intraday simulation, but we did perform day-ahead simulations using several different estimations of uncertainty in forecasts (see Section 3.5.5).

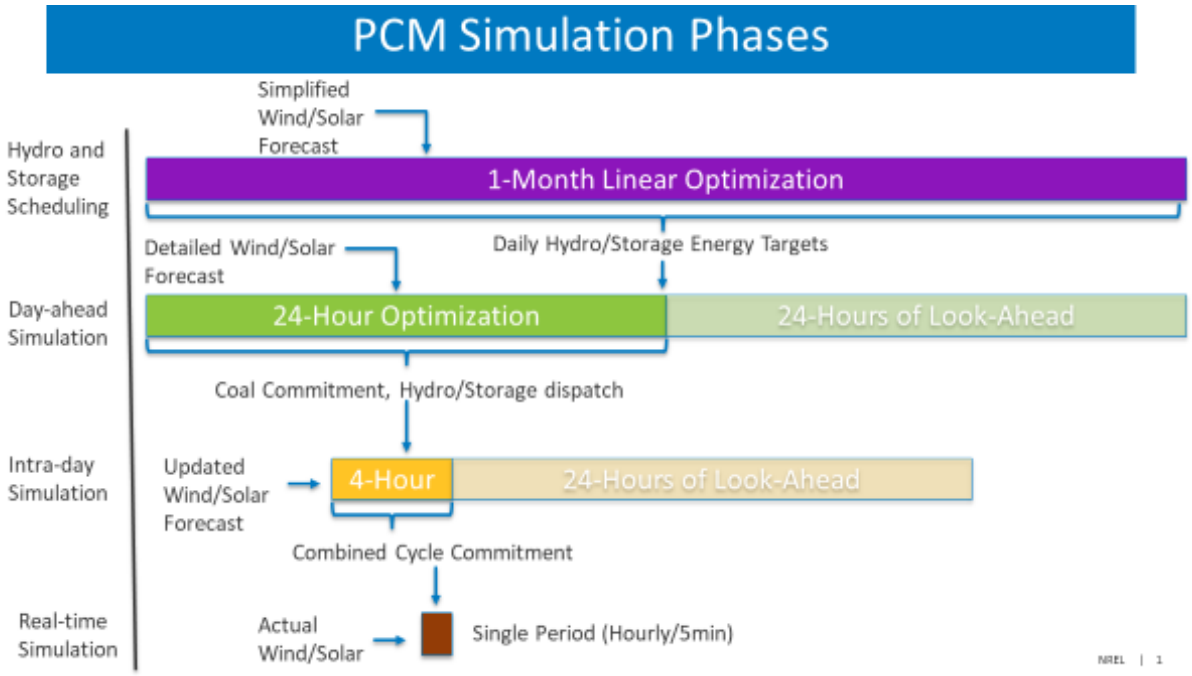

Figure 11. Simulation steps to run the PCM

PCMs are typically run as single-operator models and assume perfect information availability across regions, which is both unrealistic (leading to a solution that is lower in cost than reality) and computationally burdensome. To address these challenges and better reflect market friction and latency between operating regions, NREL designed a geographic decomposition method (Barrows et al. 2019), and we used that method in NARIS. The unit commitment and economic dispatch problem is decomposed into the independent system operator (ISO) and utility regions. This decomposition method is based on three steps: interchange forecast, decomposed unit commitment, and power flow reconciliation. This method presents two major benefits by

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reflecting actual system conditions and reducing computational time by allowing parallelization of the simulation. No hurdle rate or wheeling charge is added to flow power between regions; this assumes more coordination in dispatch than occurs in today's system in some regions.

ReEDS is a zonal model, aggregating actual transmission buses, lines, generators, and loads to a single node for each zone. For the production cost modeling, full nodal detail is maintained. Therefore, new generation capacity, retirement decisions, and transmission expansion must be decomposed from the zonal ReEDS results into the nodal PCM.

The first step to translate a ReEDS result is to determine which units in the PCM are retired. For noncoal units, ReEDS provides a capacity of generation by type for each zone that should be retired. Coal units are tracked individually in ReEDS (as they tend to be larger, and fewer new ones are built), rather than as an aggregated capacity for each zone. Each PCM node is mapped back to a ReEDS zone, and PCM generation capacity within each zone is retired until the ReEDS retirement amount is reached. For noncoal units, units are prioritized for retirement based on their heat rate, retiring the least efficient units first.

The next step is to add new units. Again, ReEDS provides the expanded capacity by type for each zone. That new capacity is broken down into reasonable generator sizes and placed at PCM nodes. Nodes are prioritized for connecting new generation by first adding units to nodes with generation that had been retired, which is followed by placing units at high-voltage and well-connected (i.e., number of lines and summed capacity of those lines) nodes. New wind and solar locations are determined by reV geospatial tool (Maclaurin et al. 2019) and are connected to PCM nodes by placing them at the closest high-voltage bus.

Expanded transmission built by ReEDS is also translated to the PCM. We simplified expanded transmission by assuming all new lines are direct current (DC). This reduces the complexity of adding new alternating current (AC) lines, as new DC lines do not impact loop flow on the existing network. However, this does increase the operational flexibility of these lines. The goal of this process is to represent the ReEDS modeled increases to interregional interfaces, and DC lines do that. Bloom et al. (submitted)[13] explore a method to expand AC infrastructure in a zonal-to-nodal translation, but those AC lines do not represent the same new interregional transfer capability. Designing AC infrastructure to expand interfaces while avoiding loop flow constraints for the entire continent is beyond the scope of NARIS. To avoid unrealistic unserved energy because of these AC loop flow constraints (with transformation of the generating fleet compared to today), the flow limits on AC lines and interfaces were allowed to exceed nonemergency ratings for a penalty cost of $12,000 per megawatt.

In reality, the new transmission expansion may be a combination of DC and AC infrastructure, and a variety of transmission or generation infrastructure could alleviate the AC transmission constraints. Detailed regional power flow studies are needed to determine the local and regional benefits of each option. To test the potential overall cost impact of these two assumptions (DC modeling in production cost tool and penalty on AC violations), we made cost estimates of

[13] For more information, see "Interconnections Seam Study," NREL, https://www.nrel.gov/analysis/seams.html.

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infrastructure to solve the issue in the model. These are both overestimates of potential cost impacts, because the optimal solution would be better than this simplification. For example:

- If we calculated costs to consider the costs of making all AC ReEDS expansion lines into DC (including converter stations), the cost increase could represent 0.4% of total system costs in the Low Cost VG scenario. This is an overestimate of the impact, because not all new lines would be DC, but this gives us an idea about how significant the assumption could be. This estimate is calculated by multiplying the AC build (in GW) by the cost of the converter stations (80,000 MW * $253,000 per megawatt assumed cost of DC converter stations).
- If new transmission infrastructure were built to augment every violated line to accommodate its maximum 5-minute violation, it would add up to 0.1% to the total continental cost in the Low Cost VG scenario (5 TW-mi of violation * $1,347/MW-mi). Some of these costs are already considered in the ReEDS model, which includes costs for intrazonal transmission lines for new generation. Other scenarios would likely have similar adders, making comparisons of scenarios consistent without this adder.

End points for the new lines were determined by connecting strongly connected buses within the two regions between which ReEDS chose to add new transmission capacity. When possible, because new lines should relieve congestion, buses on opposing sides of an enforced transmission constraint were chosen to connect the new lines. Given the varying sizes of ReEDS regions, some new transmission capacity between two regions was modeled with multiple new lines, while other regions were modeled with just one new line. The aggregate capacity of the new DC lines between any two regions is set by the amount ReEDS expanded the transmission between them.

2.1.4 Resource Adequacy Modeling: PRAS

Resource adequacy refers to the ability of a power system to serve electricity demand with an acceptably low risk of failure because of shortfalls in power supply or deliverability. The Probabilistic Resource Adequacy Suite (PRAS [Stephen 2021]) is an NREL-developed collection of tools for quantifying this shortfall risk in terms of standard probabilistic risk metrics, such as loss-of-load hours (LOLH), loss-of-load expectation (LOLE), and expected unserved energy (EUE). PRAS estimates these metrics using a sequential Monte Carlo analysis that performs a simplified power flow (see Figure 12, page 26) to confirm supply exceeds demand for sequences of random generator outage patterns. The reported metrics for NARIS are:

- **Loss-of-load hours (LOLH)**: LOLH is "generally defined as the expected number of hours per period (often one year) when a system's hourly demand is projected to exceed the generating capacity" (NERC 2018). It is evaluated using not only the peak hours or days but every hour of the year.
- **Expected unserved energy (EUE)**: EUE is "the summation of the expected number of megawatt hours of demand that will not be served in a given period as a result of demand exceeding the available capacity across all hours" (NERC 2018). For NARIS, annual EUE is reported, representing the sum of EUE in all hours of the year. It quantifies both the probability and magnitude of a shortfall occurrence, but as a result cannot distinguish between a small, likely shortfall and a large, unlikely one. EUE can also be reported as normalized EUE by expressing the expected energy shortfall as a fraction (usually in

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parts per million, or ppm) of total energy demand in the period; this is convenient for comparing reliability levels across different systems.

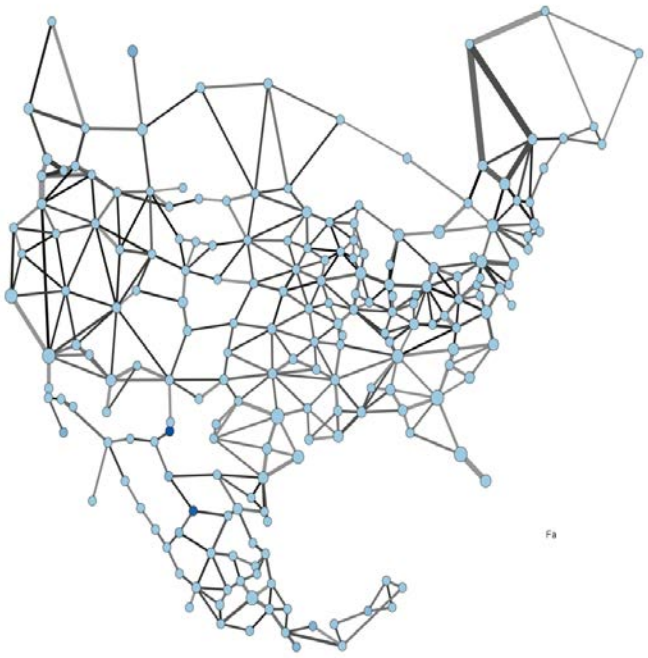

Figure 12. Transmission network representation in PRAS

Figure depicts the connectivity in the PRAS model. Circles represent regions, while lines represent interfaces.

For NARIS, PRAS was used to simulate many alternative realizations of simplified annual hourly power system operations over a year. Each realization corresponds to operations under a different collection of representatively sampled thermal generator unplanned outage profiles. The simulation performs a simplified operational dispatch on every random sample, at every period. The simplified dispatch constrains the flow between regions to the available transmission capacity while recording the time and location of events where supply cannot meet demand.

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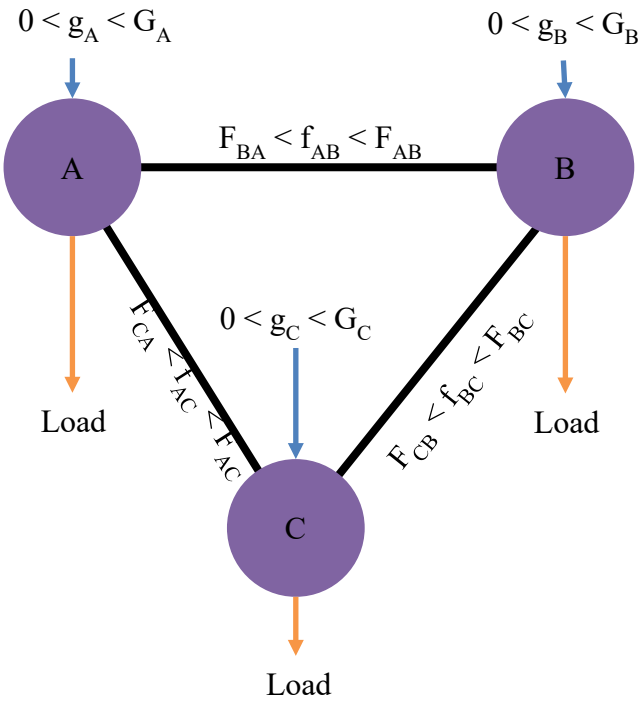

Figure 13. Diagram of PRAS zonal balancing

PRAS performs an optimized power flow (transport model) for every sample for each zone, determining whether generation and import supply is sufficient to meet demand (Load) in each zone. Constraints include enforcing that generation (g) is less than generating capacity (G) and that interface flow (f) is within flow limits (F_{AC}).

By simulating continent-wide system operations under a wide range of generator outages conditions, the risk of encountering a system state in which load is unserved because of a supply or deliverability shortfall can be quantified probabilistically and compared to risk levels of today's grid or industry standards.

To perform these simulations fast enough to make simulating hundreds of thousands of years of operations practical, PRAS makes more simplifying assumptions than a nodal static or dynamic power flow model. PRAS does not model power flow between buses but rather groups buses into regions (zones). Power transfer between buses within a single region is assumed to take place on a "copper sheet" with no intraregional transfer limits or line reliability limitations being considered. Power transfers between regions are modeled with a simple power balance ("pipe-and-bubble" or transport model)[14] representation constrained by the thermal capacities of interregional lines (in NARIS, all lines were assumed to be 100% reliable). The operational objective was to minimize the system's unserved energy, and unit-level generating costs were not considered.

These simplifications are consistent with commercial resource adequacy models used in industry (e.g., the NERC Long-Term Reliability Assessment). Resource adequacy is a necessary, but not sufficient, condition for power system reliability, and resource adequacy modeling is intended to

[14] The transport model assumes all lines and interfaces are controllable, and it is different from a DC-optimal power flow model, which ensures Kirchoff's voltage law is respected.

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complement, not replace, other kinds of modeling that can evaluate additional operating considerations, such as generator flexibility (ramp rates and unit commitment constraints), AC power flow feasibility, and transient stability issues, albeit for many fewer potential operating conditions.

Capacity expansion models such as ReEDS perform a simplified internal resource adequacy assessment to maintain computational tractability.[15] For systems with large contributions of variable and energy-limited resources (e.g., storage), such as those being studied in NARIS, it is desirable to supplement this basic evaluation with a more rigorous probabilistic risk assessment using a dedicated resource adequacy tool such as PRAS. In this case, the generation and transmission build-out determined by ReEDS is provided to PRAS, which reports probabilistic risk metrics (LOLE and normalized EUE) corresponding to the system build-out.

PRAS is run hourly with wind, solar, run-of-river hydropower, and load time series data as described in Section 2.2 (the 7-year period represents over 60,000 hours). PRAS was configured in NARIS to ignore monthly energy constraints associated with reservoir hydropower, thus treating this class of resource as capacity that is available to be dispatched. PLEXOS modeling for NARIS demonstrated that hydropower does have the flexibility to contribute significantly during the most important hours (Section 3.4). Pumped-storage hydropower and ReEDS-built storage (mostly 4-hour batteries) were dispatched as energy-limited storage resources. These storage resources are optimized for providing capacity; they charge when capacity is available in a region, and discharge only when it is needed. Market operations of a storage device could potentially reduce the ability of storage to provide capacity to a region, specifically if forecasting error led to suboptimal storage dispatch.

PRAS was developed in part to improve on existing techniques for representing transmission-constrained systems that include significant generation from variable renewable sources that are correlated with load. The key limitations to PRAS are the data inputs (which are limited to the 7 years for which we have consistent, time-synchronous load, wind, and solar data), and zonal transmission representation. N-1 analysis and dynamic transmission modeling are important for overall reliability assessment, but these are not considered in adequacy analysis. In this report, the PRAS results for the 2024 model and 2050 in the Low Cost VG and BAU scenarios are described. See Section 3.2.1 for a comparison with modeling from NERC and others.

[15] ReEDS uses a planning reserve margin, with wind and solar resources contributing based on an hourly estimate of the most important hours in each region.

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2.2 Data

2.2.1 Wind and Solar Resource

High-quality, highly resolved wind and solar resource information is important for understanding how the North American grid could evolve and operate in the future. Figure 1 (page 4) shows the wind and solar resource throughout the continent. The solar data for NARIS (see Figure 1) were developed using NREL's National Solar Radiation Data Base, which is based on satellite-based observations of the atmosphere. The database has a 4-km by 4-km spatial resolution and half-hourly temporal resolution covering the 18 years from 1998 to 2017.

We used the Weather Research and Forecasting model (WRF)[16] (Skamarock et al. 2008) to simulate wind speeds for Mexico and Canada by extending existing WRF runs for the United States. The WRF model is a community numerical weather prediction model maintained by the National Center for Atmospheric Research in the United States. It has been successfully applied to wind studies and resource assessments (e.g., Draxl et al. 2013; Carvalho et al. 2014;; Garcia-Diez et al. 2012; Ji-Hang et al. 2014; Lundquist et al. 2014). The WRF model allows for accurate simulations of winds near the surface and at heights that are important for wind energy purposes. WRF's ability to downscale to required resolutions allows for modeling mesoscale features, such as fronts, sea breezes, or winds influenced by orography, which are all important factors in describing the wind characteristics over the North American continent.

For NARIS, data were simulated over Mexico and Canada and output every 5 minutes on a 2-km grid following the WIND (Wind Integration National Dataset) Toolkit setup for the United States for consistency. The details of the setup, and meteorological validation, are available in Draxl et al. (2015). The simulations for Mexico and Canada were different than the WIND Toolkit setup in only a few aspects.[17] Figure 14 shows the three different domains that were used in the study; all three are publicly available. Most wind sites in Canada were in Domain A. To ensure consistency with Domain A, Domain B sites were bias-corrected using time-synchronous information from nearby sites in the area overlapping Domain A and Domain B. We bias-corrected the wind speeds and confirmed that annual power output shows no bias between Domain A and Domain B in and near the overlapping region.

[16] "Weather Research and Forecasting Model," National Center for Atmospheric Research, https://www.mmm.ucar.edu/weather-research-and-forecasting-model.

[17] A few changes were needed because of numerical stability and the switch to a newer WRF version. The Mellor–Yamada–Nakanishi–Niino boundary layer parameterization was used. And for numerical stability, we changed the mixing term (dif_opt = 2) and added time off-centering for vertical sound waves (epssm = 0.5), no nudging was applied. Moreover, we upgraded to WRF v3.7.1 with recent versions of netcdf (4.6) with pnetcdf for faster implementations.

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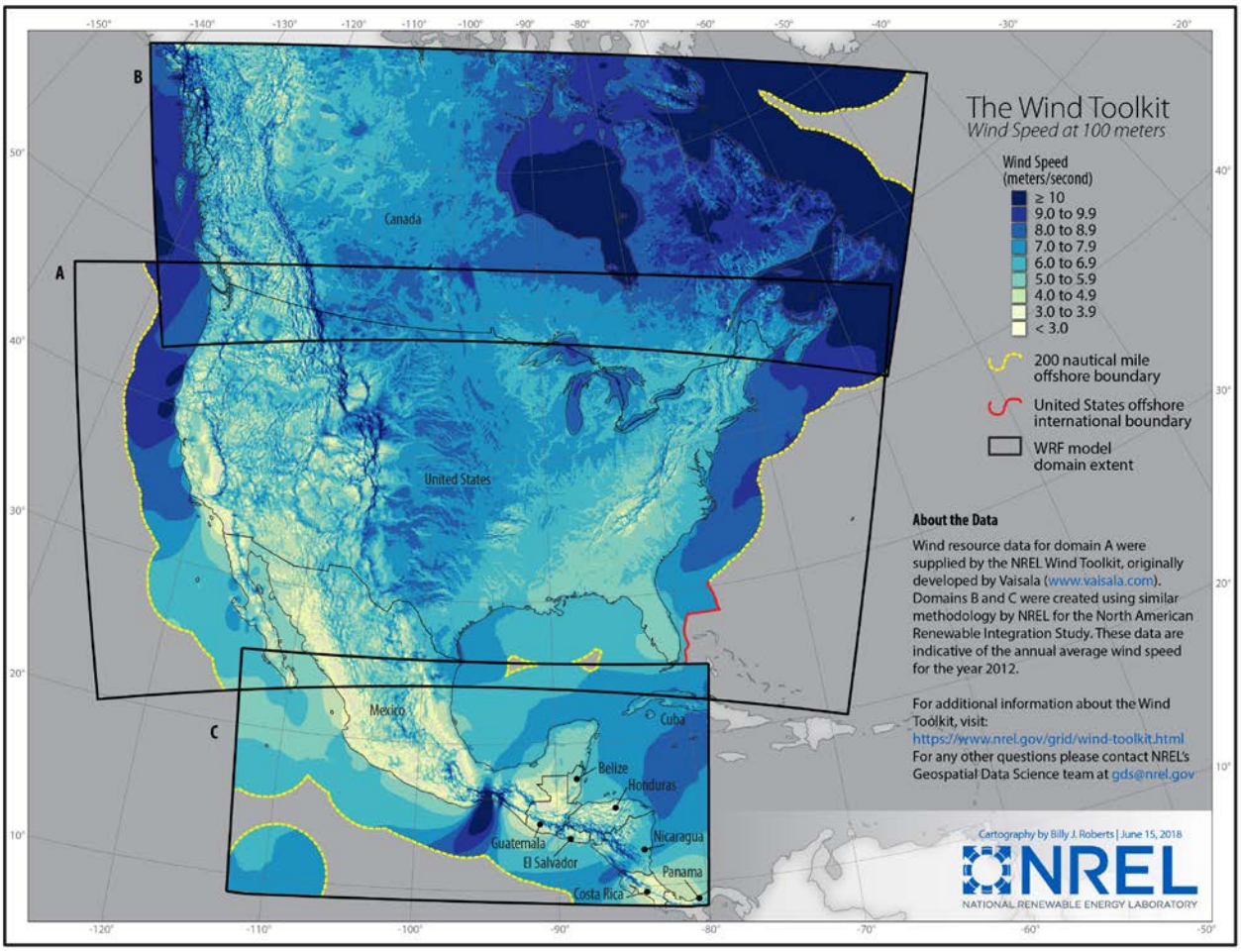

Figure 14. The three domains used in NARIS for wind modeling

Wind and solar data were processed using the NREL System Advisor Model to determine 5-minute resolution generation profiles. All the wind[18] and solar[19] data sets are publicly available in their native resource formats. The cost and performance projections for capacity expansion modeling were consistent across the continent with the 2018 ATB. The amount, location, and transmission spur line costs for new onshore wind and PV resources in NARIS were assessed using reV (Maclaurin et al. 2019; Rossol, Buster, and Bannister 2021) for input to ReEDS and other models. The modeled wind turbine power curve is consistent with improvements made for the 2019 ATB. The wind turbine technology used for the 2050 PCM was based on future technology performance projections from the 2019 ATB (Cole et al. 2019) to better represent the specific power curve of a future (circa 2030) wind turbine.[20] For utility-scale solar PV, panels with inverter loading ratios of 1.3 and 1-axis tracking were assumed (and parameters from the 2019 ATB were also used). For distributed PV, a mixture of orientations, including flat and a

[18] "NREL Wind Integration National Dataset," NREL, https://registry.opendata.aws/nrel-pds-wtk/.
[19] "NSRDB: National Solar Radiation Database," NREL, https://nsrdb.nrel.gov/.
[20] Icing impacts were modeled as reducing the plant output to zero when the temperature was below 0ºC and 95% humidity; low-temperature cutout was assumed to happen at -35ºC

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variety of tilted orientations based on Sigrin et al. (2018) were assumed (Gagnon et al. 2016). Day-ahead forecasts were used for wind and solar based on the European Centre for Medium-Range Weather Forecasts (ECMWF). The ECMWF historical data were downloaded and processed using identical System Advisor Model parameters. Continent-wide real data time series were insufficient to tune any of the state-of-the-art solar forecasting methods (e.g., Dobbs et al. 2017). The WRF model has also been extended to improve solar forecasting with WRF-Solar,[21] but it was not used for NARIS.

The wind forecast data were bias-corrected with simple annual correction factors based on the ratio of annual generation in the forecasts to actual generation. The forecasted profiles were blended with the actual profiles at various ratios to produce the forecasts described in Section 3.5.5. The 10% mean absolute error (MAE, see formula below) wind forecast was created with a 1/3 actual, 2/3 forecast blend (MAE calculated at plant-level and then averaged). This approach represents improvements state-of-the-art wind power forecasts have over the raw ECMWF implementation, which is intended for a wide variety of uses and has less-granular spatial resolution than the WRF model. The 5% MAE wind forecast was created with a 2/3 actual, 1/3 forecast blend, and represents an intraday forecast time horizon.

$$MAE = \frac{\sum_{i=Site}\sum_{t=time}\left|Actual_{i,t} - Predicted_{i,t}\right|}{Number\ of\ Sites \times Number\ of\ time\ intervals}$$

2.2.2 Load

Load data were obtained from a variety of sources for 2007–2015. The multiyear time series is important for consistent time-synchronous patterns with the 2007–2013 wind and solar data. The sources of the data were:

- **Independent System Operator (ISO) and Regional Transmission Organization (RTO) Regions:** For ISO/RTO regions, the load data were either downloaded or requested at the most granular spatial resolution available to the public.
- **Utilities:** For utilities outside ISOs in the United States, data were obtained from Federal Energy Regulatory Commission Form 714. For Canada, data were obtained from provincial sources directly for regions outside ISOs.[22]
- **Mexico:** For Mexico, load data from PRODESEN 2018 were used in NARIS.

All load data were cleaned of problems, which were often either erroneous time zone stamps or erroneous data during the hours of switching to or from Daylight Savings Time. The data were extrapolated to 2050 for most scenarios by a simple scalar factor based on extrapolated annual demand projections from the U.S. Energy Information Administration (EIA), Canada's National Energy Board (NEB), and Mexico's Secretaría de Energía (SENER). This means the annual energy demand for all meteorological years is identical for 2050, but the peak demand and hourly shapes are different. The load factor for each year will be the same because the scalar multiplier is the same for every hour; this will also preserve all correlations between load, wind,

[21] "WRF-SOLAR," National Center for Atmospheric Research, https://ral.ucar.edu/pressroom/features/wrf-solar.
[22] Hourly profiles for Prince Edward Island were taken from the hourly shapes from New Brunswick, scaled to peak load in Prince Edward Island.

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and solar for the future year analysis. The exception to these descriptions is the electrification scenarios, which are discussed in Section 3.5.4.

2.2.3 Hydropower

Hydropower generation is a potential source of flexible, carbon-free generation and storage to the grid. Hydropower technologies in North America include run-of-river hydropower (which has power outputs that depend primarily on water inflow at any given time), reservoir hydropower (which can store significant amounts of water and shift energy), and pumped-storage hydropower. The operation of hydropower turbines is very flexible. The overall constraints to hydropower flexibility can be complicated to model, as they come from various physical and institutional sources. Some of these key sources include:

- **Cascading Constraints (Physical):** When hydropower generators exist in a series of cascaded reservoirs in a basin, the inflows at lower reservoirs depend on the outflows from upper reservoirs.
- **Hydrology Constraints (Physical):** When and where water becomes available to dams is a key constraint on hydropower flexibility and generator outputs. In some seasons, even large reservoirs can fill and need to flow water at high levels at all times.
- **Flow Requirements (Institutional):** Requirements for water usage from downstream users for agricultural, recreational, environmental, and other needs impact mandatory flow requirements from dams. These detailed constraints are generally not modeled in power systems models, but are represented with proxy variables for minimum generation, ramp rates, and other characteristics.

For NARIS, the starting point for hydropower dispatch assumptions were the assumptions used in the Eastern Renewable Generation Integration Study (Bloom et al. 2016) for the Eastern Interconnection, the California Low Carbon Grid Study (Brinkman et al. 2016) in the Western Interconnection, and PRODESEN in Mexico. These assumptions were refined based on feedback from the NARIS Technical Review Committee for the PLEXOS modeling. Refinements included:

- Energy limit adjustments for generators in the Hydro Quebec, Manitoba Hydro, and Bonneville Power Administration service areas.
- More-constraining ramp rates for Eastern Interconnection and Hydro Quebec generators. For Hydro Quebec, this helped act as a proxy for cascading constraints[23] that are not included in the continental model.
- Refinements to the timescale of flexibility (e.g., optimization over a day or a week, and pure run-of-river with no adjustability) at various dams in the Hydro Quebec and Bonneville Power Administration service areas.

[23] Cascaded reservoirs have complicated intertemporal interactions that require significant data inputs and add computational complexities to the modeling. These constraints are typically not included in interconnection-sized production cost studies. In the Western Interconnection, the flexibility limits caused by these types of constraints are often modeled by constraining the outputs of individual dams to historical flows (e.g., treating dams as run of river). For Hydro Quebec, we constrained flexibility with a ramp rate to represent the system-wide ramping limitations of a cascaded system. We also added ramping limitations to the generators in the Eastern Interconnection—including limitations not used in previous studies—to address cascading and other flexibility limitations.

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On average, these changes better represent the flexibility of the hydropower generation. See Section 3.4.3 for detailed analysis of hydropower flexibility results from the modeling. Table 6 shows some of the key sources and values for hydropower assumptions in the NARIS PLEXOS model.

Table 6. Hydropower Assumptions[a]

Metric	Eastern Interconnection	Western Interconnection	Quebec Interconnection
Water-year used to estimate energy limits (hourly, monthly, or daily)[b]	2006	2005	Multiyear average
Energy limit sources	Eastern Renewable Generation Integration Study (original sources include U.S. EIA, Southwestern Power Administration, Southeastern Power Administration, U.S. Army Corps of Engineers, and provincial sources)[a]	Western Electricity Coordinating Council and Bonneville Power Administration	Hydro Quebec
Monthly, daily, and hourly (run-of-river) optimization windows (capacity-weighted percentage)[b]	79% Monthly 12% Daily 9% Hourly	50% Monthly 11% Daily 39% Hourly	100% Monthly
Ramp rate (Percentage of maximum capacity per minute)[d]	1.1%	0.5%–1.6%	0.2%–0.5%
Minimum generation level range (Percentage of maximum capacity)[e]	0%–20%	0%–45%	20%

[a] The table does not include pumped-storage hydropower.

[b] The water-years are intended to be reasonable representations of a "typical" year. Using time-synchronous data is less important with hydropower than it is with wind, solar, or load because the hourly shapes of the water flows into a reservoir are not necessarily correlated with the actual power outputs from the dam.

[c] The optimization windows represent the time-frames in which the hydropower generation can shift energy. A daily limit would limit the total generation from that unit within a day, subject to the other constraints. For the Eastern Interconnection, the optimization window does not reflect a plant-specific representation; generic parameters were used until dispatch looked similar to historical dispatch (see below for a description). Hydropower in Quebec has more than monthly flexibility; interseasonal and interannual flexibility were not studied in NARIS.

[d] This value constrains the ramp rates of the generators. It is directly comparable to assumed ramp rates for thermal plants in Table 5.

[e] For the Eastern Interconnection and the Quebec Interconnection, a minimum generation value of 20% of maximum capacity was assumed, or the largest value feasible if monthly energy limits require capacity factors of less than 20%. See below for an analysis of minimum generation levels by season.

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The mixture of flexibility timescales, minimum/maximum generation levels, energy limits, and modeling methodologies lead to different flexibility characteristics at different times of the year. To dispatch the hydropower generators with monthly optimization windows, the PLEXOS model runs a simplified monthly dispatch called the MT (Medium-Term) model that categorizes every hour of each month into five categories (or time-slices). It then optimizes dispatch for these time-slices and then determines a daily energy limit for each generator. This energy limit is then optimized in the unit commitment model, along with the hydropower with daily energy limits. The hydropower generation is locked in during the unit commitment, and it does not re-optimize during real-time dispatch.

The goal of NARIS was to represent the overall regional character of the dispatch of hydropower generation—not to accurately represent unit-specific detail for every generator. The character of the hydropower dispatch profiles is qualitatively similar to what was seen in ISOs in 2017, based on figures in the 2017 Hydropower Market Report (Uria-Martinez et al. 2018).

For context, the fall week studied in Section 3.4.3 demonstrates the bounds of operation that these hydropower flexibility assumptions provide. In the United States, there is about 50 GW of operating envelope between minimum generation levels (which coincide with low-load periods) and maximum generation levels (which coincide with high-load periods), providing a reasonable look at the available flexibility given these assumptions. About 27 GW of this 50 GW is in the Western Interconnection, and the rest is in the Eastern Interconnection.

Figure 15 shows the weekly maximum and minimum values of U.S. hydropower generation in the PLEXOS model. The figure is one way of visualizing the flexibility the model allows the hydropower, although there are limitations within the envelope of operation (e.g., ramping and daily/hourly limits). The minimum is on average 50% less than the average weekly operation, and the maximum is less than double the average for a typical week. Different regions may have differing levels of flexibility, depending on season, water conditions, and other factors.

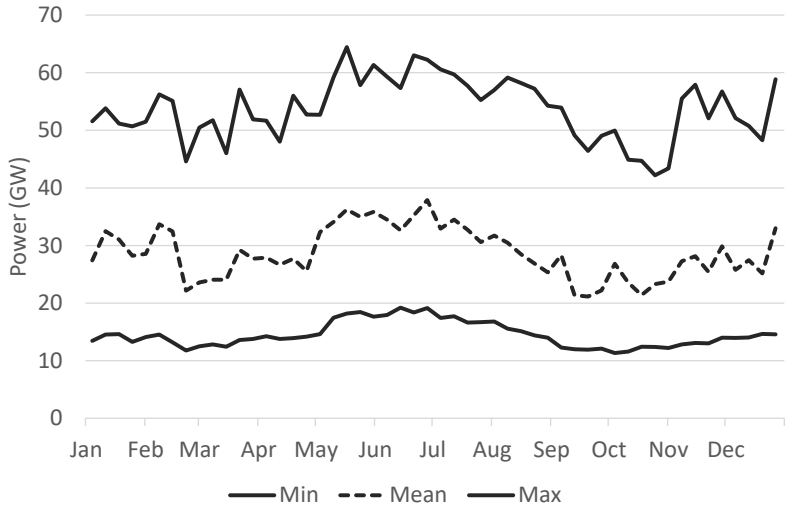

Figure 15. Weekly maximum, mean, and minimum hydropower generation from U.S. generators

These weekly maximum and minimum values show the envelope within which hydropower operates in the United States. A variety of factors (including ramping limits, daily limits, and hourly limits) further limit the flexibility within this envelope.

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To test the impacts of these flexibility assumptions we ran model sensitivities with flexibility eliminated from conventional hydropower resources (treating everything as run of river). Section 3.4.4 presents the results of this analysis, which demonstrate the benefits of hydropower flexibility to a future scenario with very high wind and solar generation.

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3 Results

In this section, we discuss the key conclusions of NARIS for the United States. Although many conclusions are not easily categorized, they are presented in separate sections for improved readability: overview (Section 3.1), adequacy (Section 3.2), transmission (Section 3.3), flexibility (Section 3.4), and general scenario conclusions (Section 3.5).

3.1 Scenario Overview

Figure 16 and Figure 17 show the U.S. annual generation and capacity respectively by technology type in the core scenarios compared to a near-term (2024) year in the model. 2024 was selected as a near-term year because the composition of the power system in that year is reasonably well known and that is the basis year for the planning cases used to develop some of the models (see Section 2.1.3). The scenarios were designed using traditional planning methods (using regional planning reserve margin constraints in the ReEDS model) and we demonstrated capacity adequacy using stochastic Monte Carlo methods in PRAS.

Consistent among the scenarios are the major growth in wind generation and the reduction in thermal generation (including coal, nuclear, and natural gas). The largest variation in the core scenarios is the overall increase in generation (mostly from wind) in the Electrification scenario. Another significant difference is the reduction in gas generation in the scenarios that include a carbon limitation (80% reduction in the Carbon Constrained and Electrification relative to 2005 Emissions). All scenarios have a reduction in coal and nuclear generation, and an increase in wind and solar. Gas and hydropower generation and capacity was consistent in most of the scenarios (but gas is higher in the BAU versus 2024 and the other core scenarios). Renewable contributions in the scenarios studied vary from 50% (BAU) to 79% (Electrification), and the Low Cost VG and Carbon Constrained scenarios were at approximately 70%.

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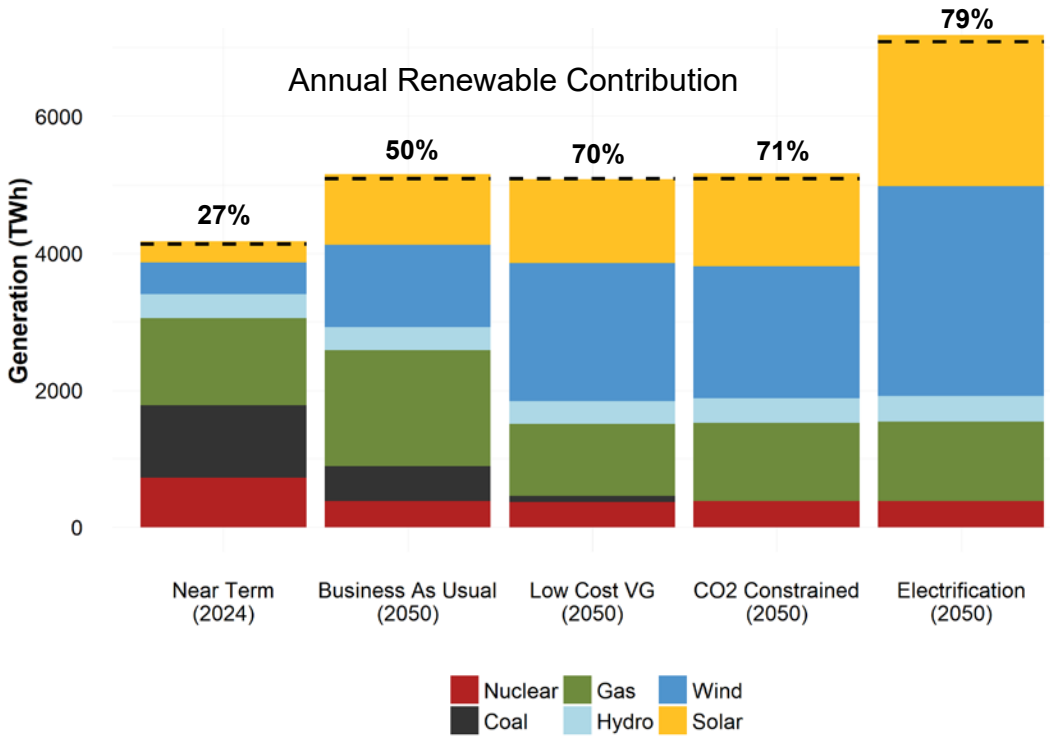

Figure 16. U.S. generation in 2024 and 2050 in the NARIS core scenarios

The dashed lines represent U.S. load (including losses). When the bars are above the load lines, net exports to Canada are happening. See Section 3.3 for a discussion of international trade, which varies widely between scenarios.

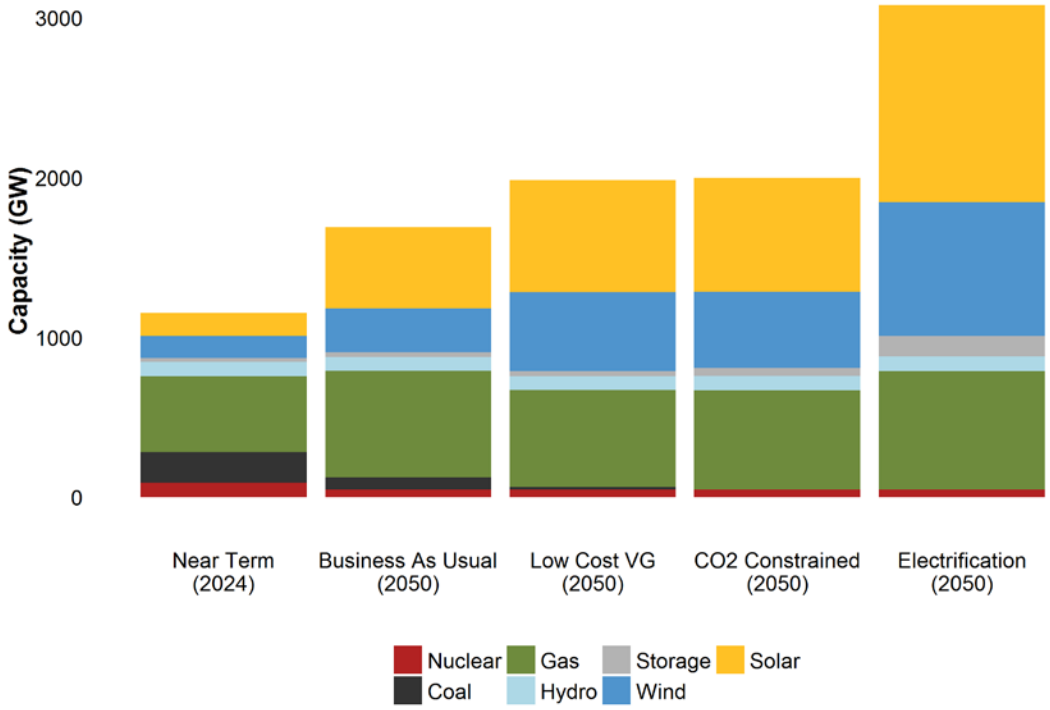

Figure 17. U.S. generation capacity in 2024 and 2050 in the NARIS core scenarios

Pumped-storage hydropower is reported in the Storage category throughout the report.

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Table 7. U.S. Generation Capacity (GW) in 2024 and 2050 in the NARIS Core Scenarios

Type	Near-Term (2024)	BAU (2050)	Low-Cost VG (2050)	Carbon Constrained (2050)	Electrification (2050)
Coal	190	80	20	0	0
Gas	470	670	610	620	740
Hydro	90	90	90	90	90
Nuclear	50	50	50	50	50
Solar	140 (20 rooftop)	510 (60 rooftop)	700 (160 rooftop)	710 (60 rooftop)	1230 (60 rooftop)
Storage	20	30	30	60	130
Wind	140	280	490	480	840

Values are rounded to the nearest 10 GW. Rooftop PV capacities are given in parentheses. Note that the dGen model was not run with new building-level demand assumptions for the Electrification scenario, so trajectories for electrification scenarios follow either the BAU or Low-Cost scenarios for rooftop PV.

The modeled deployment of technologies in the CO_2 Constrained scenario is very similar to the that of the Low-Cost VG scenario. The detailed hourly and 5-minute integration analyses focus on the Low-Cost VG scenario. More methodology development is needed to understand the hourly impacts of electrification and how flexible additional electrified end-use demands could be. This scenario is useful for comparison with the others for many key metrics, but we did not do any unit commitment or resource adequacy modeling with it. Future work (along with the recent Electrification Futures Study for the United States) could help address more-detailed issues about operations in this scenario. Some technologies (e.g., nuclear and fossil fuels with carbon capture) have assumed costs that are too high for large-scale adoption in these scenarios. However, cost breakthroughs and newer technologies (e.g., small modular reactors) could change that conclusion. For NARIS, we assumed no breakthrough changes to those technologies to understand how the grid could evolve without large-scale technological breakthrough. Any additional cost breakthroughs would help reduce overall costs. Over 99% of the wind deployed in these scenarios is onshore; ongoing changes to the North American offshore wind market and state legislation will likely change that conclusion.

Figure 18 shows the fraction of generation coming from renewable generators. Although the Low Cost VG and the CO_2 Constrained scenarios are quite similar in 2050, there is divergence in the middle years. Less-expensive wind and solar in the Low Cost VG scenario accelerates high adoption of renewables more than the other scenarios, with slowed development after 2030. The more aggressive carbon limit in the CO_2 Constrained and Electrification scenarios diverges from the BAU scenario by the early 2030s. Final renewable contributions in carbon-limited scenarios surpasses or equals the Low-Cost VG case by 2050. See Section 3.5 for discussion of emissions impacts.

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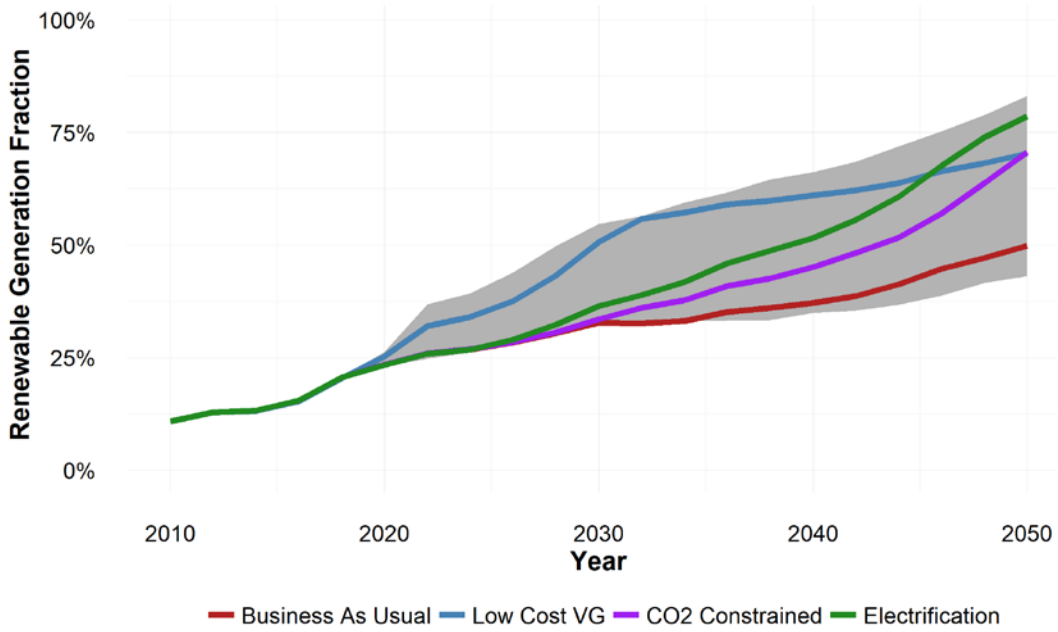

Figure 18. Fraction of generation coming from renewable generators in the United States

Core scenarios are colored. The shaded region represents the envelope of all scenarios.

3.2 Adequacy

3.2.1 Resource adequacy can be maintained in low-carbon scenarios through 2050.

To examine resource adequacy in the U.S. power system, we used PRAS to calculate EUE and loss of load hours (LOLH) from selected scenarios as built by ReEDS. As described in Section 2.1.4, PRAS can compute several common resource adequacy metrics. For NARIS, we focused on EUE and LOLH for consistency with the NERC 2020 LTRA (NERC 2020). EUE can be aggregated by country or continent, while the LOLH does not scale with system size, so the reported values are summary statistics of the NERC Assessment Areas. EUE, which is reported in megawatt-hours (MWh) and parts per million (ppm), is the unserved energy as a fraction of the total demand.

We began by assessing the adequacy of the BAU 2024, BAU 2050, and Low Cost VG 2050 scenarios as built by ReEDS. Each scenario is assessed over 7 historical meteorological years, which affects the scenario's load, wind, and solar generation output at an hourly time-scale. For each scenario and meteorological year[24] combination, we generated 10,000 sequential Monte Carlo samples of the year and used those samples to calculate EUE for each region in each hour. We report total EUE for each meteorological year, along with the average across meteorological years, for each scenario in Table 8. The NERC 2020 LTRA assessment for 2022 is also included

[24] Unusual weather events are taken into account in the 7 years of continental meteorology. Using historical years allows greater precision in wind, solar, and load modeling than using modeled future data. However, we did not consider the impacts of climate change on wind, solar, or load patterns in NARIS.

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for reference. The methods are similar, but not identical, so the numbers are not directly comparable.

Table 8. EUE by Scenario and Meteorological Year for the United States, Compared to NERC LTRA

The top part of this table presents results from the PRAS modeling for NARIS. EUE values rounded to the nearest MWh or the nearest 0.1 ppm. U.S. regions only.

Meteorological Year	BAU 2024		BAU 2050		Low Cost VG 2050	
	MWh	ppm	MWh	ppm	MWh	ppm
2007	0	0.0	0	0.0	0	0.0
2008	0	0.0	0	0.0	0	0.0
2009	0	0.0	0	0.0	0	0.0
2010	0	0.0	5,834	1.2	16,864	3.4
2011	0	0.0	10	0.0	4	0.0
2012	0	0.0	0	0.0	158	0.0
2013	0	0.0	0	0.0	0	0.0
Annual Average	0	0.0	835	0.2	2,432	0.5
NERC 2020 LTRA Values for Comparison						
2022 Assessment Year[a]	12,845	2.7				

[a] WECC-CAMX (California and Mexico) region is excluded from this average because it was an outlier in the 2022 and 2024 assessment years, with over 1,000,000 MWh of EUE.

The results demonstrated adequacy generally comparable to or better than the 2020 NERC LTRA for the contemporary grid for the scenarios examined. All scenarios had at least five times lower EUE compared to today's grid. The NERC assessments are done using industry tools and variety of statistical methods (depending on region); some using Monte Carlo methods similar to PRAS. PRAS, however, uses consistent simultaneous assessment for all regions for each hour of the simulation. This helps ensure consistency in treatment of both variable renewable and other resources within and between regions. Though there is no national EUE standard in the United States, for reference, the Australian resource adequacy standard was recently changed from 20 ppm to 6 ppm.[25]

Only 2010 meteorological conditions led to more than one part per million EUE. In particular, an early fall, record-setting heatwave in California in 2010 caused high loads to occur after evening drop-offs in solar output. This led to EUE in the 2050 scenarios for the 2010 meteorological year. The ReEDS model did not see the 2010 meteorological year in its decision-making (only 2012), but PRAS simulates it.

[25] "Energy Security Board Interim Reliability Measures – RRO Trigger", https://energyministers.gov.au/publications/energy-security-board-rro-trigger-rule-change.

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Table 9 shows LOLH statistics in several scenarios, compared to the 2020 NERC LTRA. This method also demonstrates that the NARIS scenarios studied with this model are generally comparable in adequacy to today's grid. Note that for all comparisons with average values in LTRA, the WECC-CAMX region was excluded because it was an extreme outlier (over one TWh of EUE).

Table 9. Loss of Load Hours (LOLH) by Scenario, Compared to NERC LTRA

Metric	BAU 2024	BAU 2050	Low Cost VG 2050	2020 NERC LTRA (2022 Assessment Year)
Average LOLH of all assessment areas	0.00	0.03	0.05	0.04
Median LOLH of all assessment areas	0.00	0.00	0.00	0.00
Number of areas in "Green" category (below 0.1 LOLH)	13	12	12	10
Number of areas in "Yellow" category (0.1–2.4 LOLH)	0	1	1	2
Number of areas in "Orange" category (>2.4 LOLH	0	0	0	1

This table has variety of metrics of LOLH from the PRAS modeling compared to 2020 NERC LTRA. All numbers are for U.S. regions only. The modeled BAU 2024 outputs are different (less LOLH) from the NERC assets because the ReEDS model builds additional capacity for regions that are short on capacity. WECC-CAMX was excluded from the average, but not the median or count statistics (which are not sensitive to outliers).

To analyze how large the adequacy buffer is on average in each scenario, we repeated the analysis and uniformly scaled the time series of loads in each region to see how much additional EUE results. If a load increase yields only a small increase in EUE, we conclude that most hours had a nontrivial adequacy buffer; however, if a load increase yielded a large increase in EUE, we conclude the buffer has been exhausted in some hours. This is not standard adequacy modeling practice, but it does help identify how "overbuilt" the system is. There are trade-offs between cost and reliability for customers today and in the future, and these scenarios attempt to build a system that is generally equivalent to today's grid in adequacy.

For each load multiplier (applied by multiplying a uniform scalar value to every hour, preserving the load shapes), we calculated EUE using 1,000 Monte Carlo samples for each meteorological year (2007–2013) for three scenarios (BAU 2024, BAU 2050, and Low-cost VG 2050). To reduce computational burden and compare all scenarios with four different multipliers, we used fewer Monte Carlo draws than the runs for Table 8 and Table 9. We then averaged the results over the seven meteorological years to trace out the relationship between load multiplier and EUE, particularly looking for the inflection point that identifies the load multiplier for which most hours shift from having a buffer to having no buffer (Figure 19). This analysis showed that all scenarios stayed below 10 ppm EUE with a load multiplier of 1.10 (a 10% increase in load).

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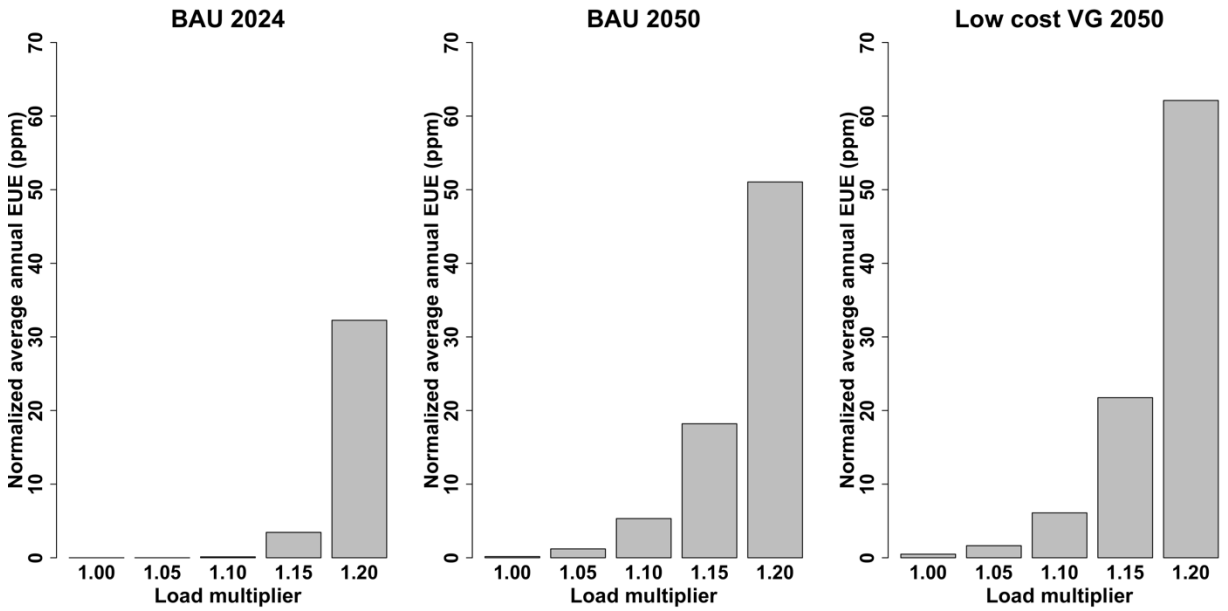

Figure 19. Normalized average aggregate EUE (ppm) by scenario and load multiplier for the United States

Each bar is the average EUE over the 2007–2013 meteorological years. The indicated load multiplier is applied uniformly to each hour of the study year. Note that loads could increase by 10% in these scenarios and still maintain EUE below 10 ppm.

The key caveats regarding the findings of resource adequacy include:

- PRAS assumes zonal transmission simplifications (in line with industry standard for adequacy models).
- As an adequacy model, PRAS does not consider unit commitment or forecast errors—only whether capacity is sufficient to serve the load in each region at each simulated hour (which is also in line with industry standard for models like PRAS).

3.2.2 All generation types can contribute to reliability in future scenarios.

Figure 20 (page 43) shows the contribution of technologies to energy and capacity adequacy (both summer and winter) based on the ReEDS modeling outcomes. For wind and solar, ReEDS considers the coincidence between hourly generation patterns and load in each region. PRAS provides additional evidence that these results produce an adequate system, subject to the caveats above.

For the United States, hydropower provides a similar contribution to energy and adequacy, and it varies greatly by region. Although hydropower energy limits are lower in late summer (when load is still high), the capacity is still available. Wind provides more energy than adequacy because on average, the wind generates less in peak load hours. Wind generation is more coincident with winter peaks than summer peaks. Solar provides similar contribution to both summer planning reserve and energy. Although solar is very well correlated with summer peak loads, additional contributions from solar eventually shift the net load peak to approximately sunset in many regions. Solar is poorly correlated with winter peak loads, as these often occur in dark hours. Thermal generators provide less energy, but significant adequacy to the grid in both

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seasons (see Section 3.2.3 for a discussion of thermal generator operation). This is because these generators have nonzero marginal cost, and many are primarily providing adequacy and dispatched after the zero-marginal-cost renewable sources. Section 3.2.3 has a discussion of thermal generators operational patterns. The storage category is a combination of pumped-storage hydropower and batteries with 4-hour duration. Recent work by Frazier et al. (2020) characterized impacts on storage duration on planning reserves for a variety of scenarios and modeled most of the additional storage resources as 2-hour and 4-hour batteries. At higher levels of renewable generation (and storage deployment), longer-duration storage becomes more important.

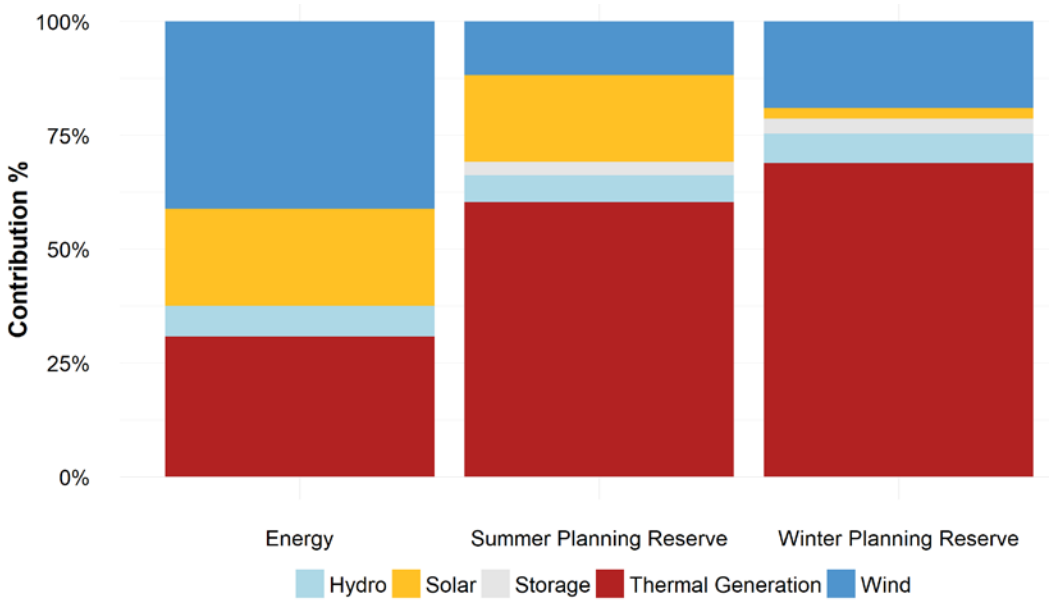

Figure 20. U.S. contribution of different technologies to energy and planning reserve in the Low Cost VG scenario

The energy and planning reserve requirements are all different, so this plot shows the ratio for comparison between technologies. Though hydropower provides similar energy and planning reserves, wind provides more energy than planning reserves, and thermal generation provides more planning reserves than energy.

Figure 21 through Figure 23 show the energy generation and planning reserve procurement (including exchange of energy and capacity) by region. In general, the regions showed similar patterns between energy and planning reserves. Regions where the energy or planning reserves are higher than the dashed line represent regions where power or capacity is being exported, and regions lower than the dashed line are importing. Importing capacity represents transfers similar to those counted by NERC in the LTRA as "net firm capacity transfers" toward resource adequacy. They also represent physical transfers of resources that are owned or operated by a balancing authority in one region but physically exist in another. The ReEDS model does not distinguish between these two categories and does ensure the physical deliverability (with zonal transmission representation) of both energy and capacity. The energy plot in Figure 21 represents the annual total, snapshots in time can look significantly different. See Section 3.3.2 for a discussion of powerflow in the PLEXOS modeling for this scenario.

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The U.S. portions of WECC outside the California Independent System Operator (CAISO) area (abbreviated in the plot below as WECC) on average send both energy and planning reserve into CAISO. CAISO imports energy and capacity in the model in 2050, which is similar to today's conditions. See Section 3.3.2 for a discussion of CAISO energy imports from the PLEXOS model results. Summer peak capacity imports in the ReEDS model in 2050 (21 GW) are in line with the contribution of imports toward resource adequacy in 2020 (16 GW).[26] The summer planning reserve need in the United States (Figure 23) is significantly greater than the winter planning reserve need (Figure 23) for most regions. This allows the United States to send capacity to Canada in the winter and procure capacity from Canada in the summer. On average, Canada also sends energy to the United States in this scenario (70 TWh in the ReEDS model).

Although these plots show the Low Cost VG scenario, the other scenarios (except electrification, which has more wind and solar generation) have generally similar breakdowns by technology (with lower renewable contributions in the BAU).

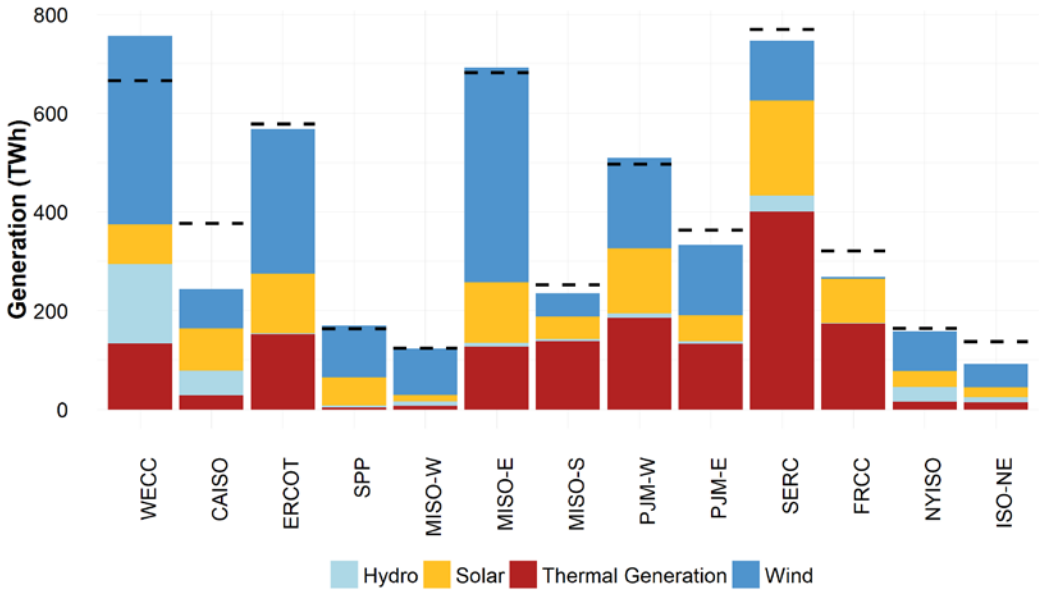

Figure 21. Energy generation in the Low Cost VG scenario in 2050

The dashed lines represent the electricity demand for each region (including losses). The region labeled WECC includes all U.S. portions of WECC, excluding CAISO. This is a ReEDS model result.

[26] The maximum import capability toward resource adequacy in CAISO for 2020 is available at https://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2020.pdf ("California ISO Maximum RA Import Capability for year 2020," CAISO).

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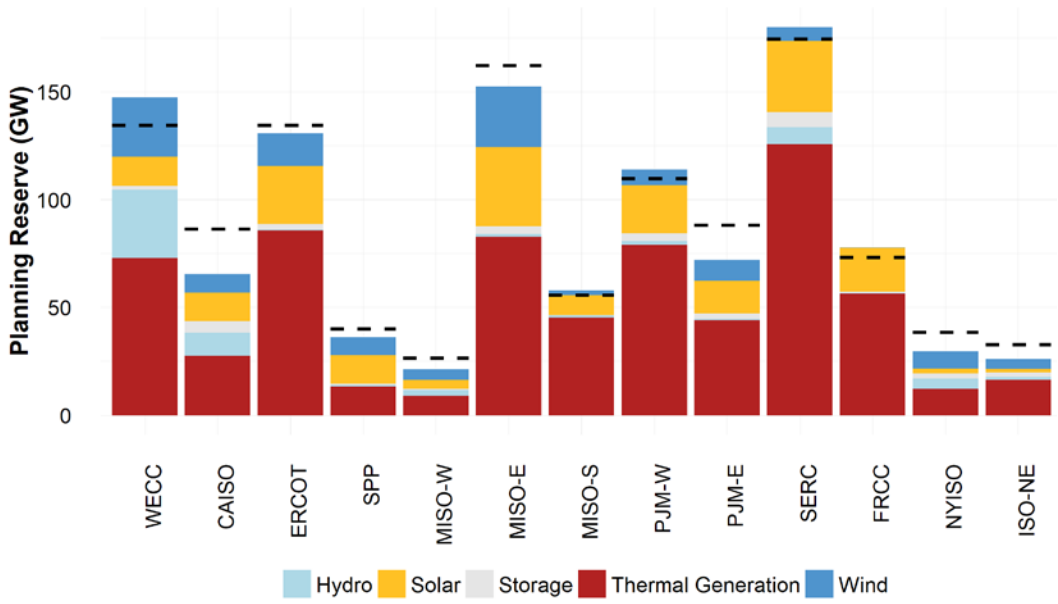

Figure 22. Summer planning reserve in the Low Cost VG scenario

The dashed lines represent the planning reserve requirement for each region. The bars represent the contribution of each resource type to the planning reserve requirement. If the bars are above the dashed line, the excess can be exported to regions that need additional planning reserves. This is comparable to the net firm capacity transfers NERC includes in the LTRA. This is a ReEDS model result.

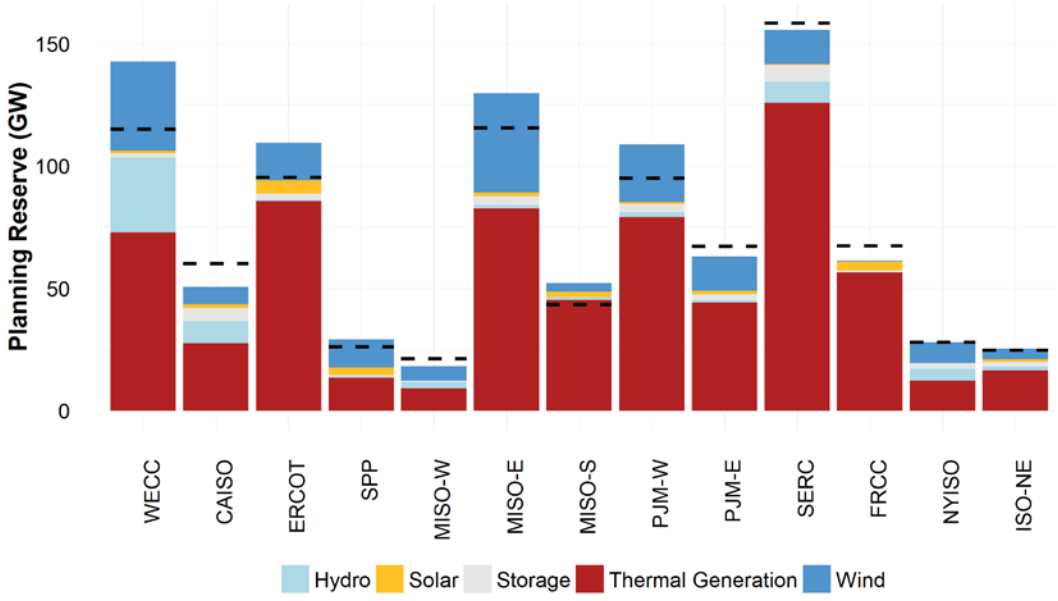

Figure 23. Winter planning reserve in the Low Cost VG scenario

The dashed lines represent the planning reserve requirement for each region. The bars represent the contribution of each resource type to the planning reserve requirement. If the bars are above the dashed line, the excess can be exported to regions that need additional planning reserves. This is comparable to the net firm capacity transfers NERC includes in the LTRA.

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Note that shifting demand patterns that are due to climate change were not in the scope of NARIS; this impact could lead to changing summer and winter peak demand requirements across North America, driven by electric heat and air conditioning.

Figure 24 shows the evolution of summer planning reserve needs in the United States through 2050 (the dashed line), along with the renewable and storage contributions to the planning reserve need (the colored lines). Planning reserve need grows by approximately 22% relative to 2020, and the additional planning reserve is met almost entirely by additional renewable generation in all scenarios. The contribution of thermal generation remains similar to 2020. In the scenario with low-cost storage, storage also plays a significant role (over 200 GW) and thermal generation plays a smaller role.

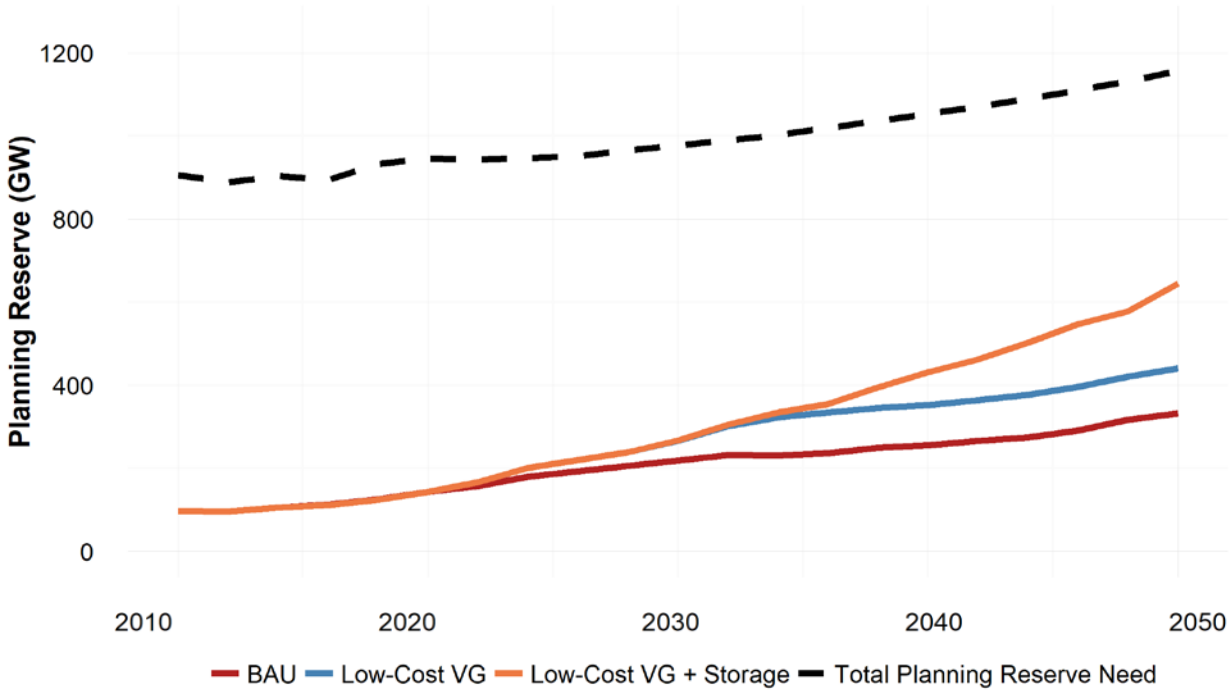

Figure 24. Contribution of renewable generators to summer planning reserve needs in the United States

Capacity contribution to planning reserves from renewables grows in all scenarios in the ReEDS model. Most of the rising peak demand (dashed line) is provided by the capacity credit from new wind and solar. Thermal capacity continues to play a role in resource adequacy to fill the remaining firm capacity needs (the gap between the requirement and the contribution from renewables and storage in each scenario). The Low Cost Storage scenario demonstrates that storage could play a major role in planning reserve contributions in the future.

3.2.3 Thermal generation operates differently in future scenarios and provides more adequacy than energy.

Though thermal generation serves a smaller portion of energy needs, it is important in the NARIS scenarios for both energy and adequacy. If other scenarios or sets of assumptions were considered (e.g., technology costs or lower carbon limits), storage or hydropower could potentially fill more of that role. During a small number of hours of the year, thermal generators are producing most of the power to the grid because load is high and/or wind and solar

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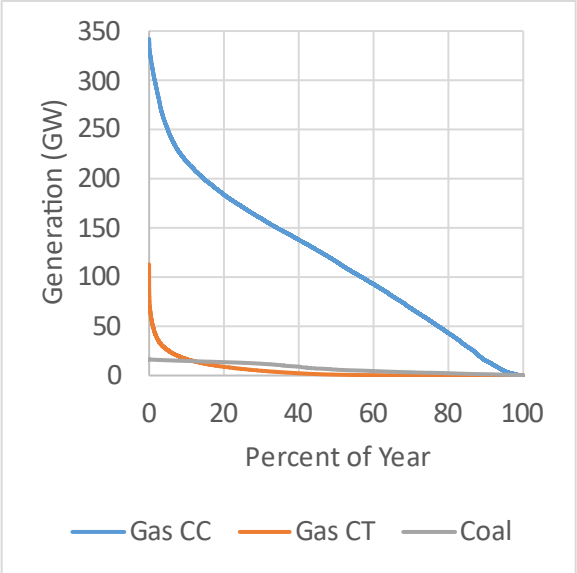
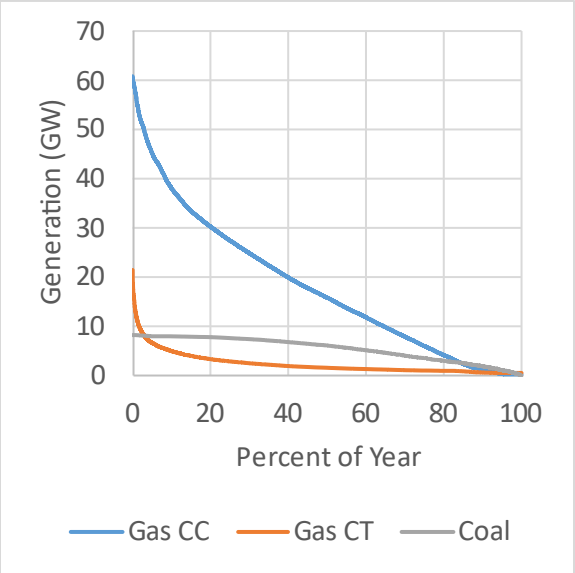
generation are low. The thermal generators are helping provide adequacy during those key hours. For many of the rest of the hours of the year, the low-marginal-cost resources (wind, solar, hydropower) are providing most of the energy.

Figure 25 shows the duration curve of gas CC and gas CT generation in the three interconnections resulting from the PLEXOS Low Cost VG 2050 scenario. Gas CTs are used primarily for adequacy in all three interconnections, seen by the high utilization exclusively in a few hours of the year at the left edge of the plot. Average capacity factors range from 2% (Eastern Interconnection) to 10% (Western Interconnection), comparable to a U.S. average of 11% in 2019.[27] Gas CCs have significant utilization in more hours of the year but still see capacity factors of 18%–31%, which is substantially lower than the 2019 average of 57% in the United States. Most coal capacity has retired by 2050 in this scenario, but without any carbon constraints (in the United States), the existing coal does have significant capacity factors (48% in the Eastern Interconnection and 62% in the Western Interconnection, with Texas having negligible coal capacity). This is comparable to the 2019 average of 48%. Nuclear generation patterns are not presented here because nuclear is assumed to be online and generating at maximum capacity whenever they are not on outage in the model. The modeling respects minimum generation levels for each generator at each 5-min operating interval. At times, little or no fossil-fueled generators are online. It is assumed for NARIS that frequency support can be provided by nuclear, hydropower, synchronous condensers, and/or advanced inverters; if additional thermal generation is required for frequency support, this would increase curtailment.



(a) Eastern Interconnection



(b) Western Interconnection

[27] Capacity factors reported for 2019 are from "Electric Power Monthly," EIA, November 2020, https://www.eia.gov/electricity/monthly/.

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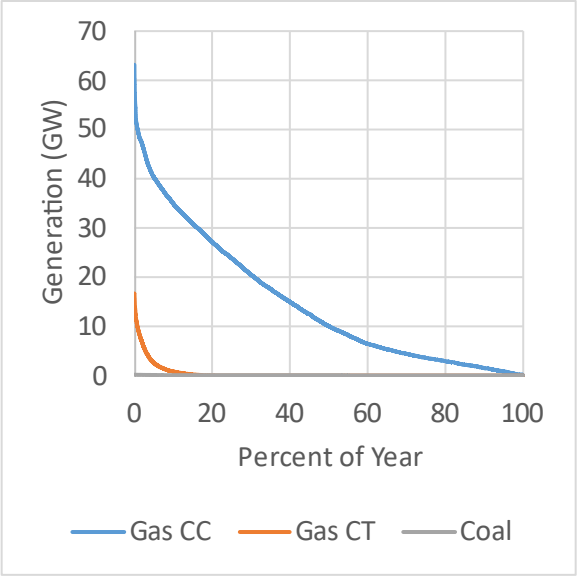

(c) Texas Interconnection

Figure 25. Thermal generation utilization in Low Cost VG scenario in 2050 by interconnection

Figure 26 through Figure 28 summarize the capacity factor of all the plants in the United States in the Low-Cost VG scenario. Most gas CTs have a capacity factor between 0% and 5%. Also, a significant number of gas CC generators with have capacity factors near zero, especially in the Eastern Interconnection and the Texas Interconnection.

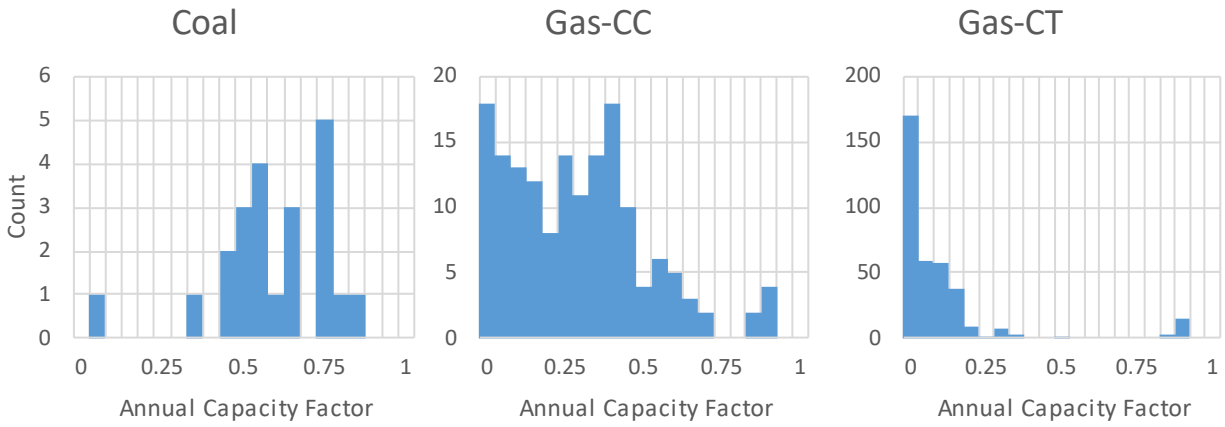

Figure 26. Thermal generation utilization in the U.S. Western Interconnection (Low Cost VG 2050)

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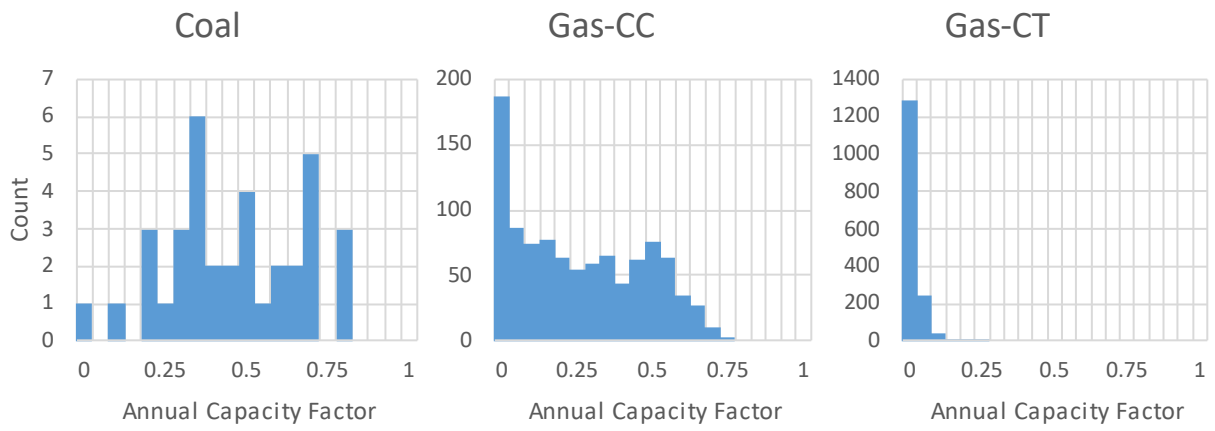

Figure 27. Thermal generation utilization in the U.S. Eastern Interconnection (Low Cost VG 2050)

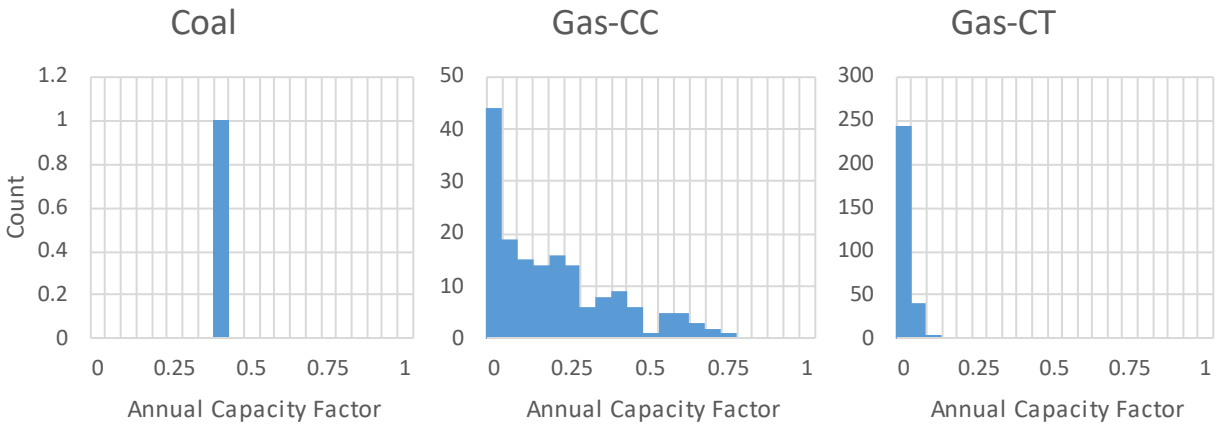

Figure 28. Thermal generation utilization in the Texas Interconnection (Low Cost VG 2050)

Although thermal generators produced less energy in these scenarios than they currently produce, they still have a major role to play in adequacy for the future system studied in these scenarios. Scenarios with higher contributions of wind, solar, and other zero-carbon resources might rely more on storage and demand response and less on coal and gas generation for adequacy. In NARIS, we did not attempt to analyze whether there would be sufficient revenues for these generators to continue operations. Some compensation method (whether based in energy markets, capacity markets, or regulations) would have to exist for these generators to be available. The cost of building these units, however, was considered in the capacity expansion modeling as part of the overall cost optimization.

3.3 Transmission

In this section, we discuss some of the transmission-related outcomes of the modeling. In Section 3.3.1, we discuss the value of transmission and results from ReEDS and PRAS, and in Section 3.3.2 we discuss utilization and the results from the PLEXOS modeling.

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3.3.1 Cooperation and transmission between regions and countries leads to economic and adequacy benefits.

Figure 29 shows transmission investments by scenario, broken out by whether the additional capacity crosses the Canada-U.S. and Mexico-U.S. borders. From this result, we see that transmission capacity increases with wind and solar contribution. The CO^2 Constrained scenario leads to higher transmission investment than the Low Cost VG scenario (despite similar VG contributions) because VG technologies have higher costs in the CO_2 Constrained scenario, thus shifting the optimal balance between transmission and VG investment. As a result, VG sited at more-optimal locations in the CO_2 Constrained scenario (possibly requiring more transmission), whereas VG can be sited at less-optimal locations closer to load centers in the Low Cost VG scenario. Although the international transmission connections look small in comparison to the increased capacity within the United States, the international expansion is also significant (3–8 GW expansion U.S.-Mexico, 10–20 GW U.S.-Canada).[28]

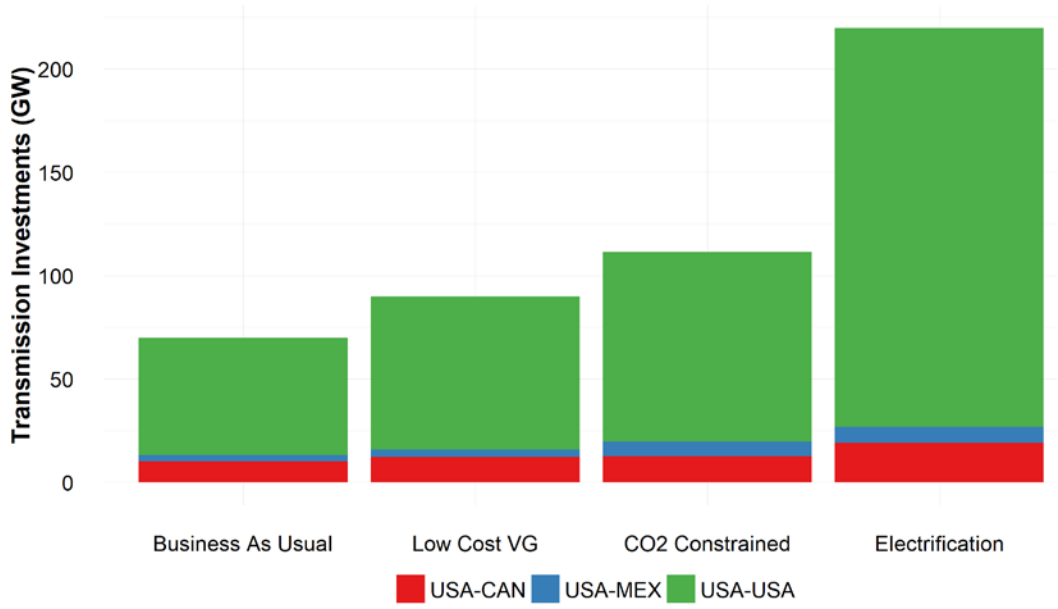

Figure 29 Added transmission capacity in the core scenarios (measured in GW of interface expansion)

Figure 30 shows a map of the transmission expansion in the core scenarios based on the ReEDS generation and transmission co-optimization. In all four cases, the model deploys new transmission infrastructure in regions throughout the United States and North America. Although many of the interfaces are developed in all scenarios, some are developed only in the Electrification scenario, where almost double the new wind capacity is built than in the other scenarios.

[28] The expansion values compare to approximately 18 GW of capacity between the United States and Canada in 2020 and 2 GW between the United States and Mexico in 2020, although most of the connection with Mexico does not connect to the interconnection in Mexico (Sistema Eléctrico Nacional).

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The transmission expansion in the model is part of a co-optimization of generation and transmission resources. Differences in resource quality or cost assumptions could lead to differences in the optimal build-out of renewable generators and transmission infrastructure both. As seen in Figure 30, however, much of the transmission that is built in the model is robust to a variety of scenarios and the assumptions we varied.

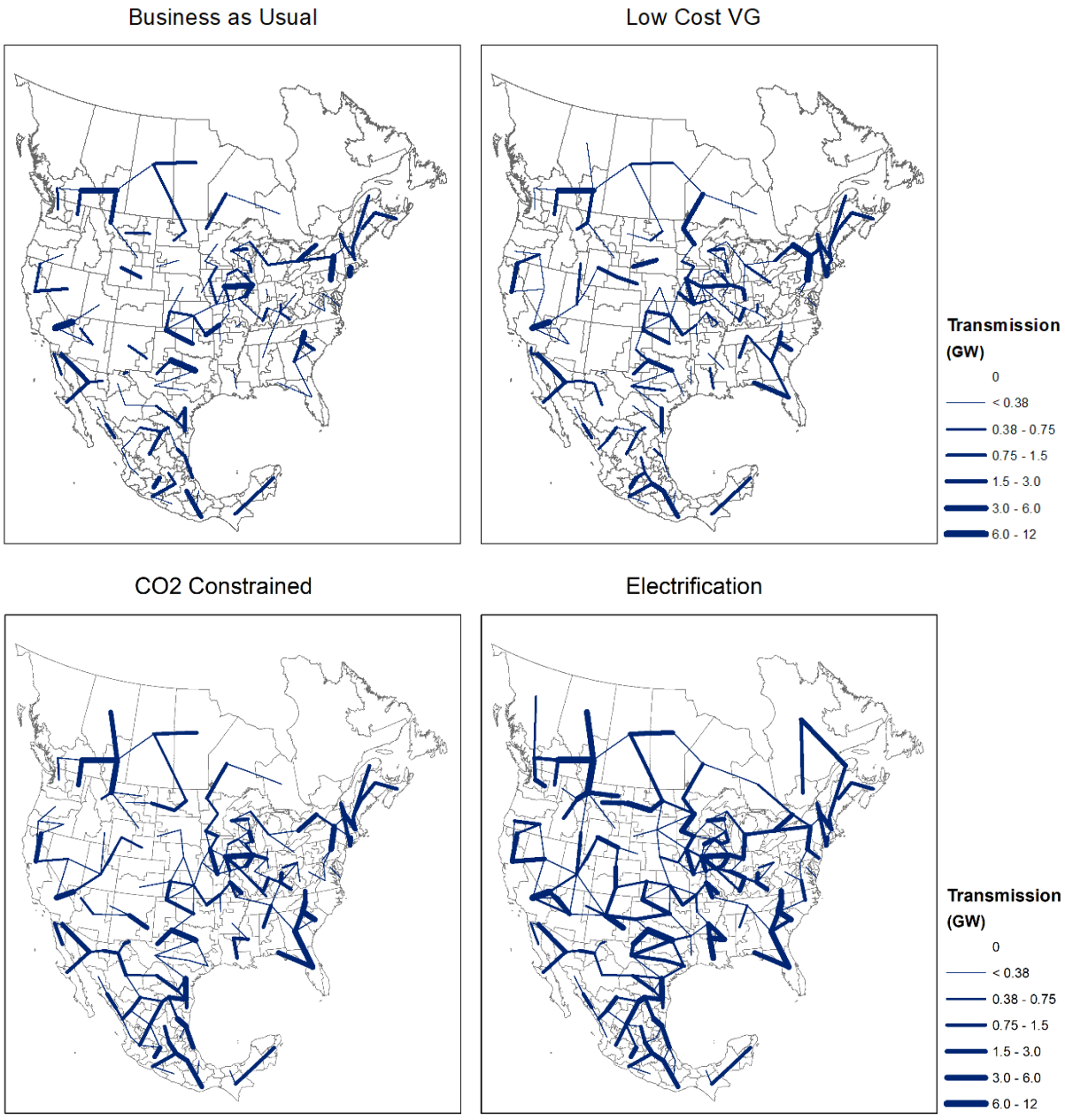

Figure 30. New transmission capacity in the core scenarios

The lines on this map represent transmission interfaces between the zones in the model, and they typically represent aggregated transmission lines.

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To understand the importance of this transmission to costs and other outcomes, we ran the ReEDS model with a variety of limitations on transmission expansion. The difference in total system costs between the constrained and unconstrained scenarios demonstrates the value to the system of the changes. We explored the following changes with scenarios (as identified in Section 1.2):

- **International Transmission Expansion:** This comparison estimated the value of allowing new international transmission capacity. It did this by comparing each core scenarios with a corresponding scenario that disallows transmission expansion across national boundaries (core scenario versus No Cross-Border Expansion scenarios in Table 2).
- **Interregional Transmission Expansion and Coordination:** This comparison estimated the value of interregional transmission capacity by comparing a scenario with limited transmission growth and its corresponding core scenario (core scenario versus No Cross-Border Expansion Uncoordinated scenarios in Table 2). The transmission cost increase was included in the optimization but in costs reported here (so that the system costs are directly comparable to the core scenarios) and the scenario represents a very low transmission build-out.
- **Interregional Transmission Expansion and Coordination with Macrogrid:** This compares the core scenarios with a predesigned macrogrid shown in Figure 32 and described later in this section (Macro Grid versus No Cross-Border Expansion Uncoordinated scenarios in Table 2).

Figure 31 shows the value of enabling each of these transmission assumptions in the model (measured as the reduction in overall system costs in ReEDS). The pattern between scenarios is similar to the overall transmission infrastructure build (Figure 29). The net value of international transmission expansion (mostly between Canada and the United States) is $10 billion–$30 billion in all the core scenarios except the BAU.[29] Benefits of increased transmission infrastructure would also occur after 2050 and those are not captured here; this represents the sum of all benefits from 2020 to 2050 in 2018 USD values. The net value of interregional transmission ranges from $70 billion to $180 billion in the core scenarios, with the higher values corresponding with scenarios with more transmission build and higher wind and solar generation levels. The macrogrid scenarios show that requiring the model to build a macrogrid with 2,700-MW HVDC (high-voltage direct current) lines (and allowing additional AC builds) would have overall net value similar to the interregional value when the model optimizes the build ($60 billon–$170 billion versus $70 billion–$180 billion). Although the net value of the macrogrid is lower than the net value of the optimal interregional expansion in the model in each scenario, benefits from the macrogrid are not well captured in the modeling. The macrogrid benefits that are not fully considered in this modeling include self-contingency, controllability, and dynamic performance benefits.

[29] The BAU has nationwide carbon limitations in Canada but only state limitations on carbon in the United States. This could possibly undercut some of the value of transmission expansion, as Canada has limited ability to import anything from the United States in this scenario.

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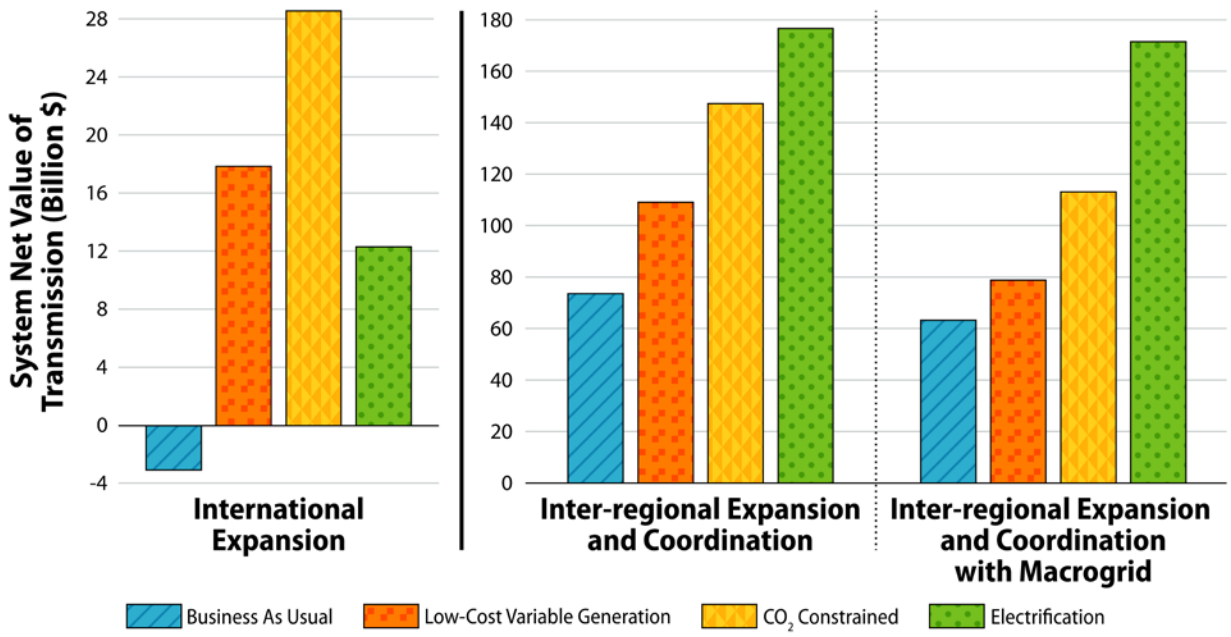

Figure 31. Continent-wide net value of transmission expansion

This plot shows the net value of allowing different transmission build assumptions in the model. It shows international transmission expansion worth $10 billion–$30 billion, interregional expansion (with or without a macrogrid) worth $60 billion–$180 billion. Note that the macrogrid has additional benefits (e.g., self-contingency and controllability) not fully captured in this modeling.

Figure 32 shows the macrogrid studied in NARIS, which is a predesigned, HVDC network that spans most of the United States and some of Canada. It expands on the work done in the Interconnections Seam Study[30] to include a likely high-value branch into Canada, as designed with help from the Technical Review Committee. These model runs might not provide sufficient evidence to conclude that the optimal AC build is better than the HVDC macrogrid (or vice versa), but both scenarios offer more than $100 billion in savings than an uncoordinated build (with less transmission expansion).

[30] "Interconnections Seam Study," NREL, https://www.nrel.gov/analysis/seams.html.

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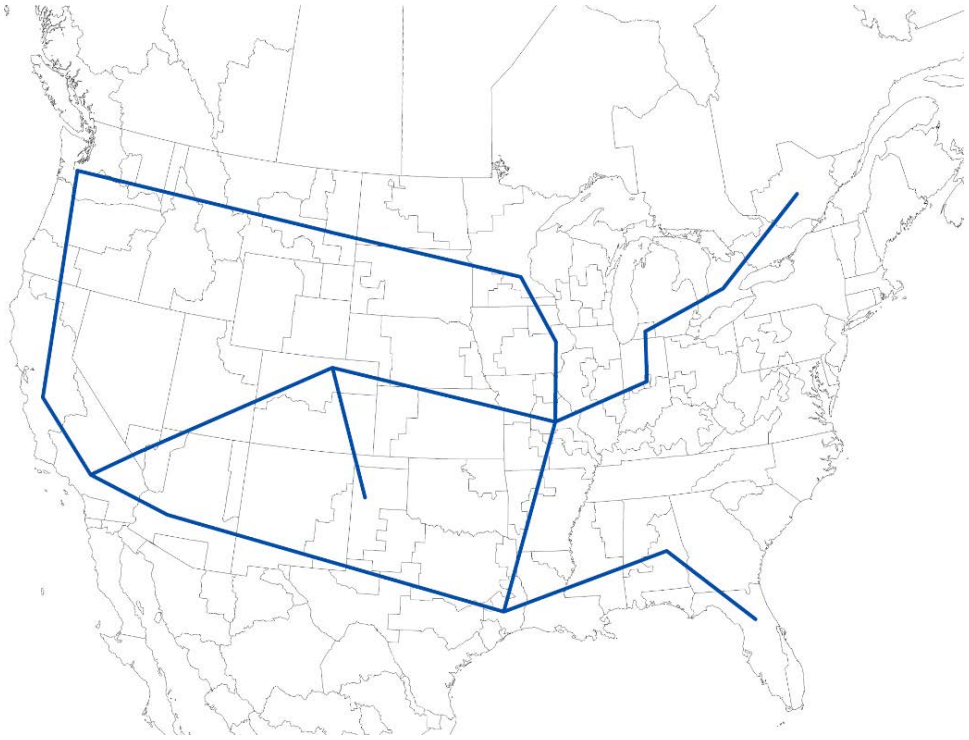

Figure 32. Macrogrid design

Additional macrogrid layouts could be more optimal than this design. Further work could help determine optimal macrogrid layouts for different scenarios, or robust macrogrid layouts.

Figure 33 and Figure 34 show the net and gross trade between the United States and Canada, respectively, through 2050. Net trade between the United States and Canada is highly sensitive to model assumptions, as can be seen from the significant spread. Some scenarios even represent net Canadian imports from the United States. However, the model results are not consistent in suggesting what net Canada exports might look like in 2050. In the NARIS companion report for Canada,[31] we discuss scenarios we ran that included a significant Canadian net export requirement (100 TWh/year by 2050), and these scenarios were similar in costs to the core scenarios. These specific scenarios are not reflected in the uncertainty bounds of Figure 33.

Gross trade between Canada and the United States (Figure 34) has a more consistent story. Although there is significant spread between the scenarios, it generally increases with continental wind and solar generation levels (which also increase with time). This demonstrates that the importance of energy exchange between the United States and Canada increases in scenarios with higher renewable deployment. In the Low Cost VG scenario, the PLEXOS model showed that despite an average flow between Canada and the United States of 4,700 MW, power flows from the United States to Canada 32% of the time. Assigning the systemwide benefits to a specific region or country is not possible without knowledge of the contracted and/or market prices.

[31] *The North American Renewable Integration Study: A Canadian Perspective*. See "North American Renewable Integration Study," NREL, https://www.nrel.gov/analysis/naris.html.

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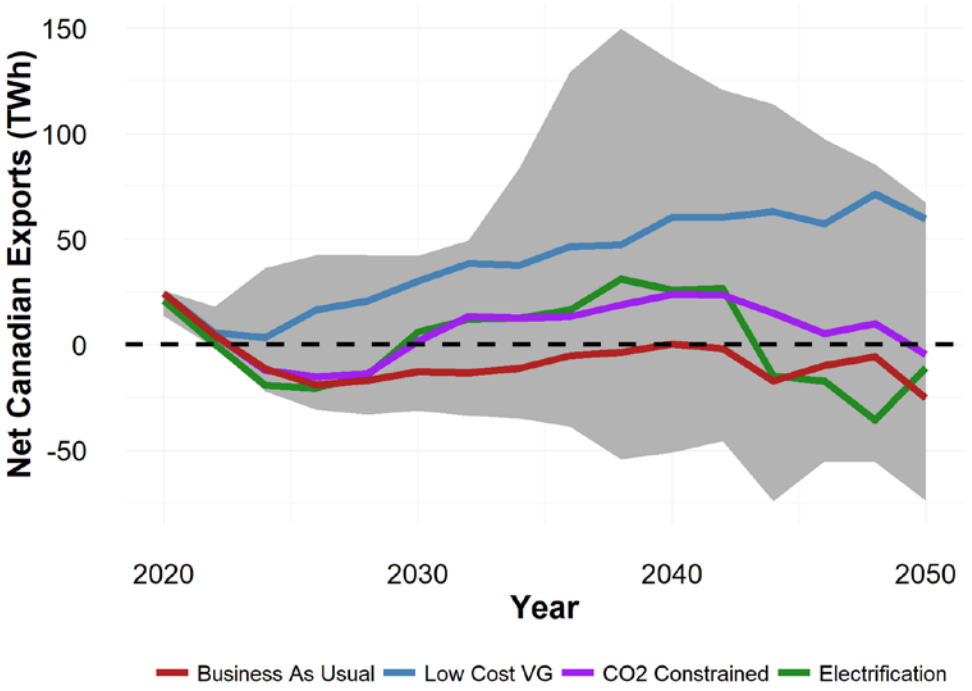

Figure 33. Net United States/Canada trade in all scenarios (core scenarios colored)

The shaded region represents the envelope of all the scenarios that are mentioned in Section 1.2. There is wide variability between the scenarios, and there is no robust conclusion regarding net exports from Canada. In the NARIS Canadian report, we discuss additional scenarios where Canadian exports were required in the model, and these scenarios showed no significant cost increases.

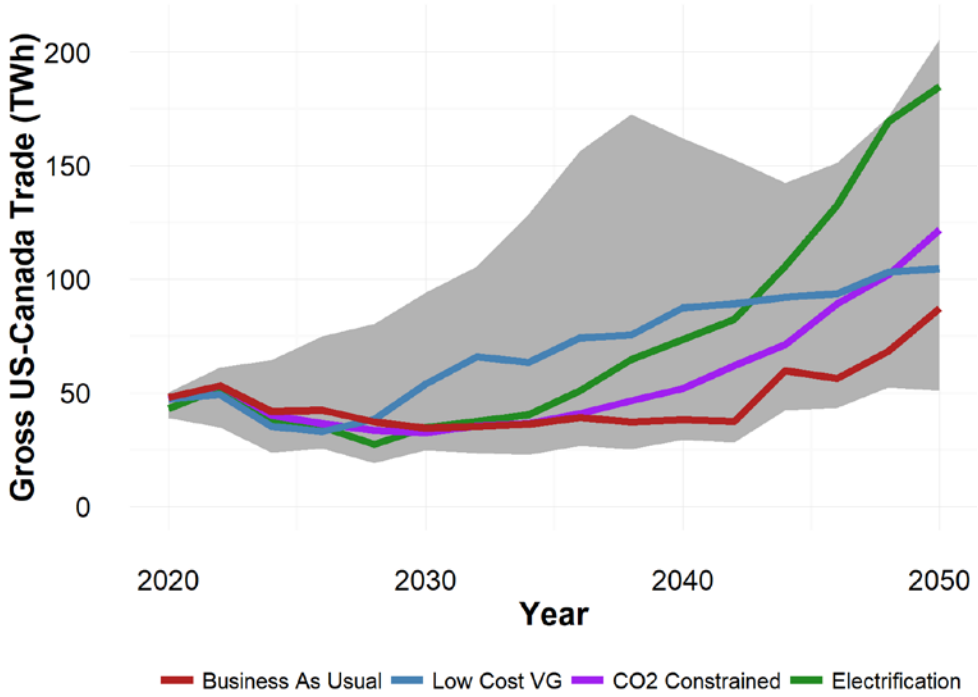

Figure 34. Gross United States/Canada trade in all scenarios (with core scenarios colored)

The shaded region represents all the scenarios that were run for the study, including variations mentioned throughout this report.

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Figure 35 and Figure 36 (page 57) show the net and gross trade between the United States and Mexico, respectively, through 2050. Net trade between the United States and Mexico is highly sensitive to model assumptions, as can be seen from the significant spread. However, gross trade between Mexico and the United States (Figure 36, page 57) has a more consistent story. Although there is significant spread between the scenarios, it generally increases in scenarios with carbon constraints in both countries. This demonstrates that the importance of energy exchange between the United States and Mexico increases in scenarios with higher renewable generation levels.

Transmission is needed for adequacy in the near-term grid, and it is even more important with higher loads and higher renewable deployment in 2050. Using the same random Monte Carlo samples that generated the EUE results discussed in Section 3.1, we computed the maximum utilization of each modeled transmission interface for each scenario in each meteorological year. Maps of these results are presented for selected scenarios in Figure 37 (BAU 2024 with 2010 meteorology) and Figure 38 (Low Cost VG 2050 with 2010 meteorology). The results are highly consistent across meteorological years (not shown here). Maximum utilization increases in the 2050 scenarios from the 2024 scenario, particularly in the Low Cost VG case. Note that as a resource adequacy model, PRAS only utilizes transmission when it is required to avoid unserved load, so the utilization maps indicate transmission requirements for adequacy rather than realistic powerflow. For the rest of the analysis in this section, economic exchanges were considered at every time-step in the modeling.

Though NARIS does demonstrate the value of cooperation and transmission, it does not demonstrate that it is impossible to achieve renewable contribution levels or reliable future grids without extensive new transmission builds. Those scenarios, if feasible, would come at a higher cost.

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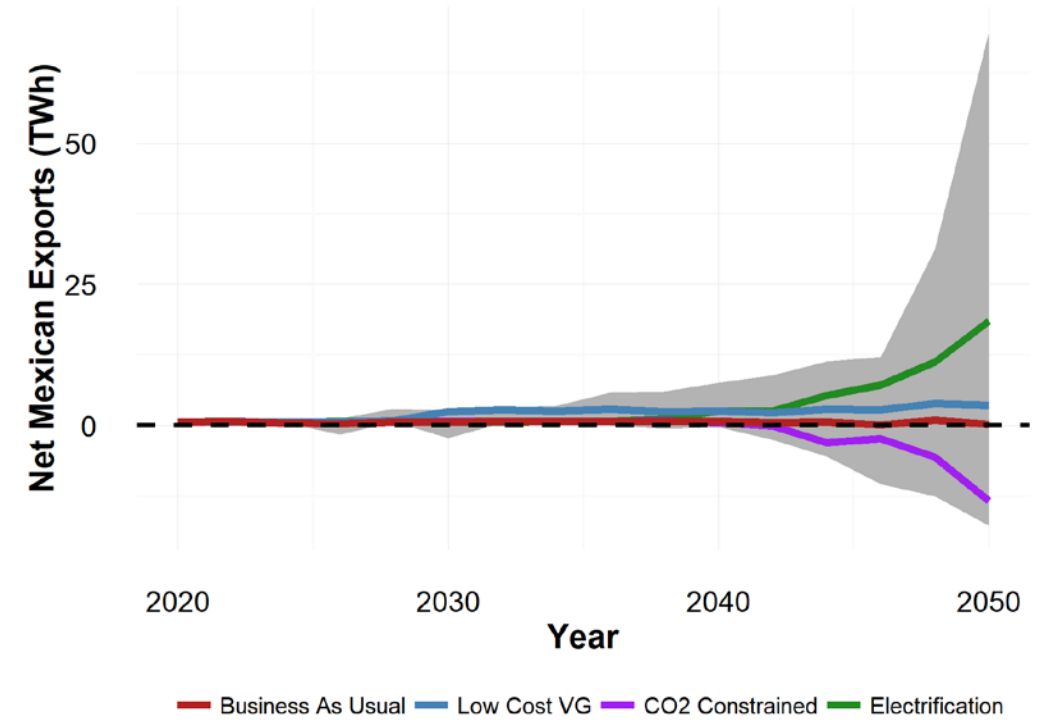

Figure 35 Net U.S./Mexico trade in all scenarios (with core scenarios colored)

The shaded region represents all the scenarios that were run for the study, including variations mentioned throughout this report.

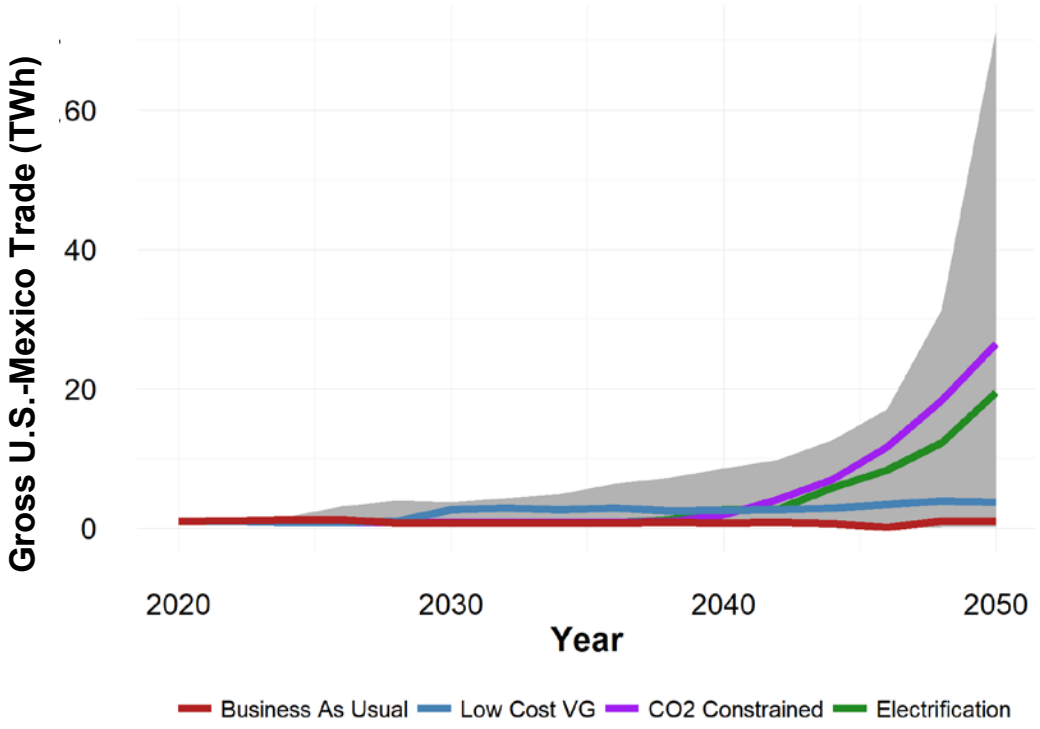

Figure 36 Gross U.S./Mexico trade in all scenarios (with core scenarios colored)

The shaded region represents all the scenarios that were run for the study, including variations mentioned throughout this report.

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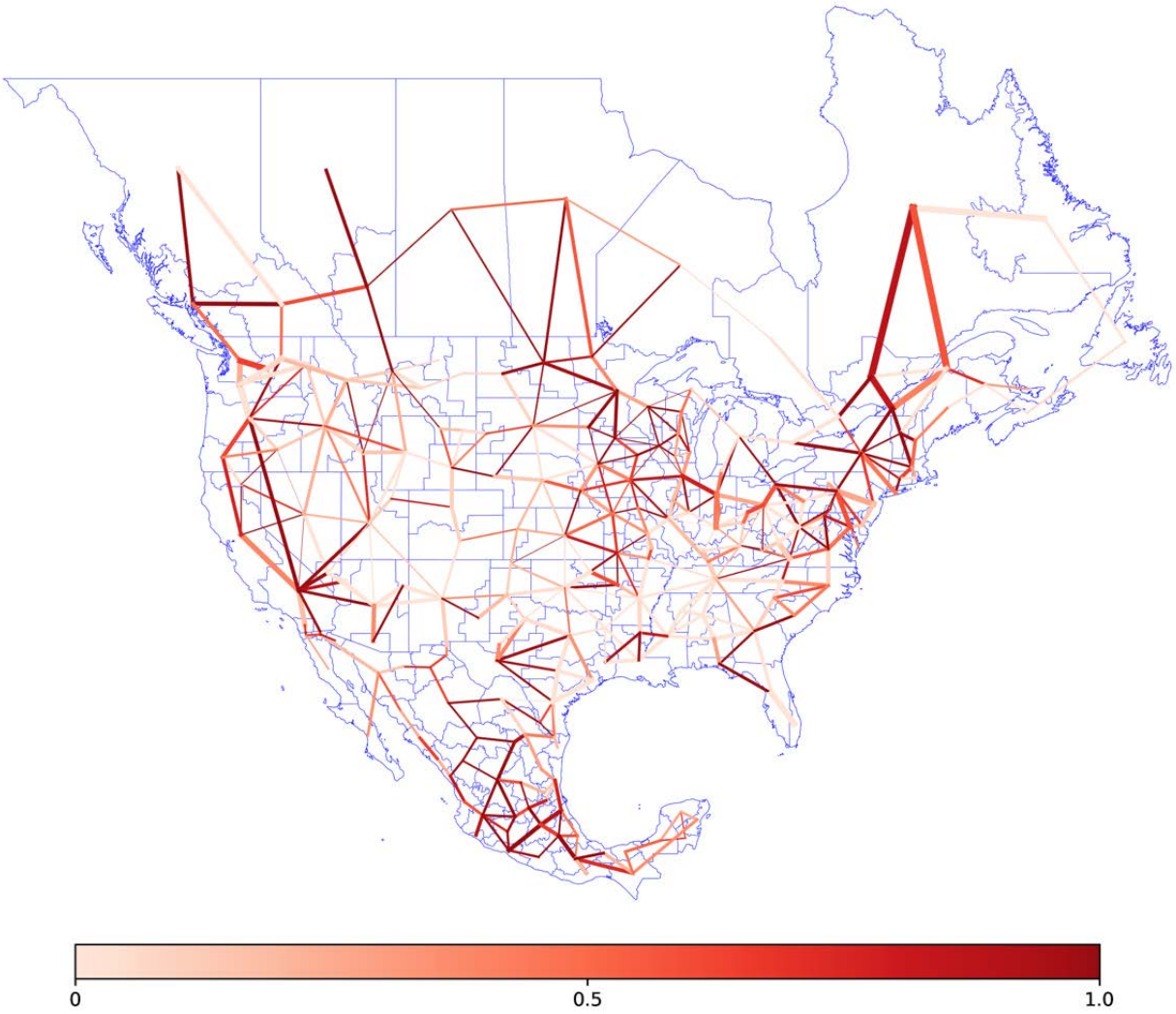

Figure 37. Maximum utilization of paths in the near-term (2024) PRAS adequacy model

The width of the lines represents the capacity of the interface between zones. The color represents the maximum hourly utilization (flow divided by capacity) during the PRAS adequacy analysis for 2010 meteorology; the plot looks similar for other years. This is not an economic dispatch; interfaces are utilized only when it is absolutely needed to serve load.

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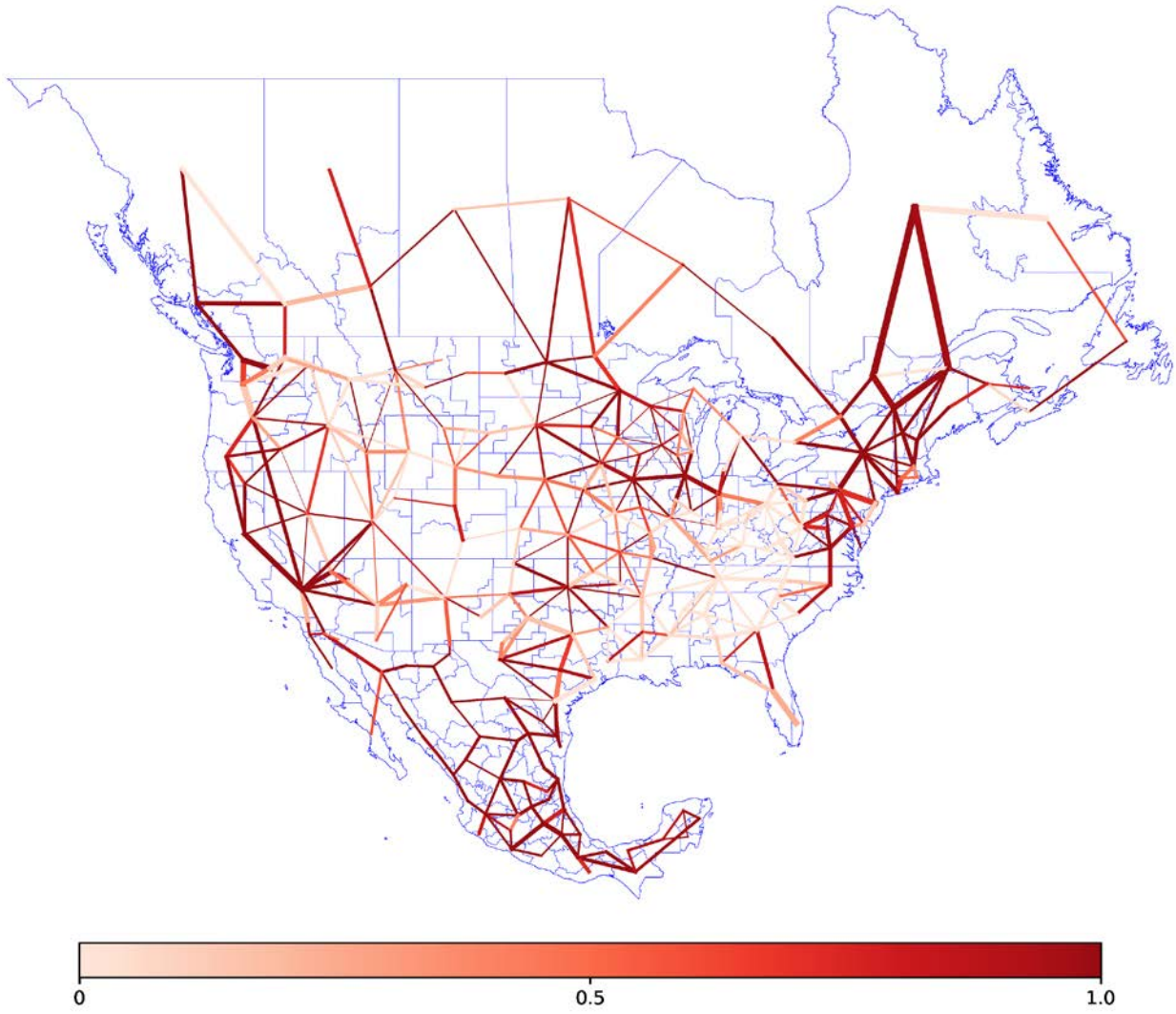

Figure 38. Maximum utilization of paths in the Low Cost VG 2050 scenario in PRAS model

The width of the lines represents the capacity of the interface between zones. The color represents the maximum hourly utilization (flow divided by capacity) during the PRAS adequacy analysis for 2010 meteorology. This is not an economic dispatch; interfaces are utilized only when it is absolutely needed to serve load.

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3.3.2 Utilization of transmission infrastructure is very high.

This section describes the utilization of the newly built transmission lines and the interfaces between regions. Figure 39 shows the utilization of lines built by the ReEDS model in the Low Cost VG 2050 scenario. Most lines have annual utilization greater than 90%, demonstrating the high value of the expanded transmission pathways in the Low Cost VG scenario. These lines are operated as DC lines in the PLEXOS modeling, which allows the model to reach higher levels of utilization than AC (see Section 2.1.3 for a discussion of the overall impact). The utilization rates are very high and are often used bidirectionally.

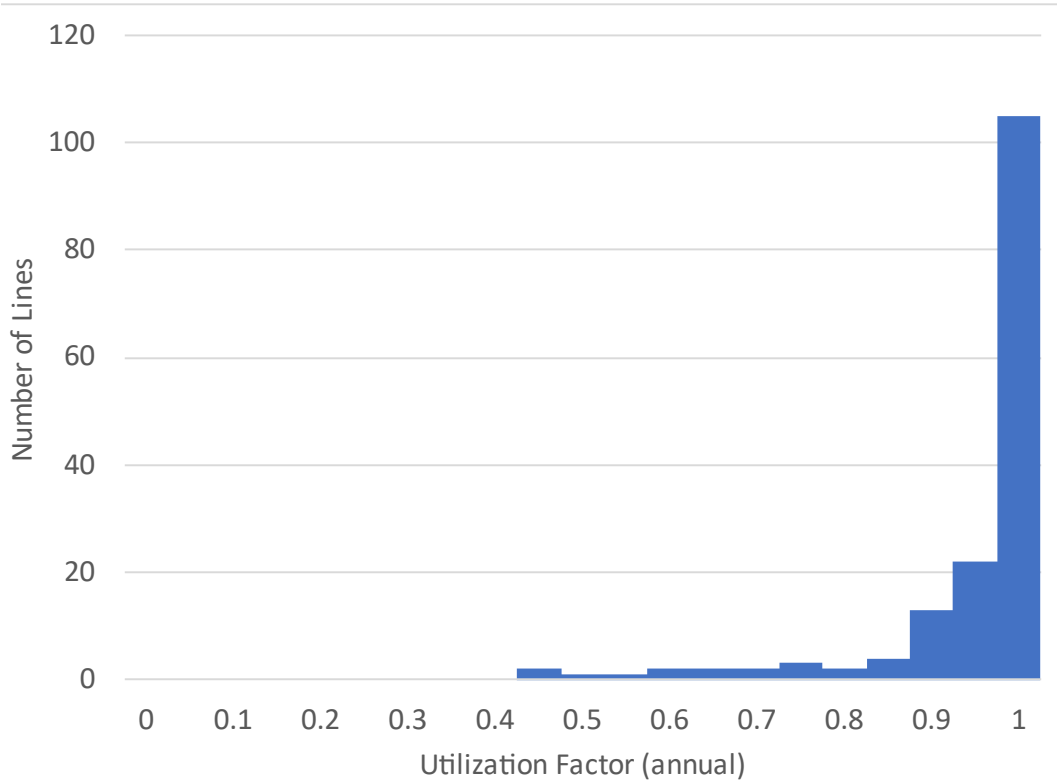

Figure 39. Histogram of total utilization of expansion lines (Low Cost VG 2050)

Figure 40 shows the net interchange between U.S. regions and their neighbors. The biggest net exchanges are from U.S. Southwest to California, the U.S. Northwest to California, the Midcontinent Independent System Operator (MISO) area to the PJM Interconnection (PJM) area, and British Columbia to the U.S. Northwest. Similar to today, California is the largest importer. The total imports into California in the model (95 TWh) are in line with recent years.[32] Flows from Quebec into the United States are split onto two different interfaces, yet both are significant. The MISO export to PJM is also substantial, which is likely due to the high-quality wind resources in MISO and strong transmission connections with PJM. Many other interfaces have smaller net flows; some of these have large flows in each direction that balance out over the year.

[32] EIA data show California imported 71 TWh in 2019, down from an annual average of 89 TWh for 2013–2017.

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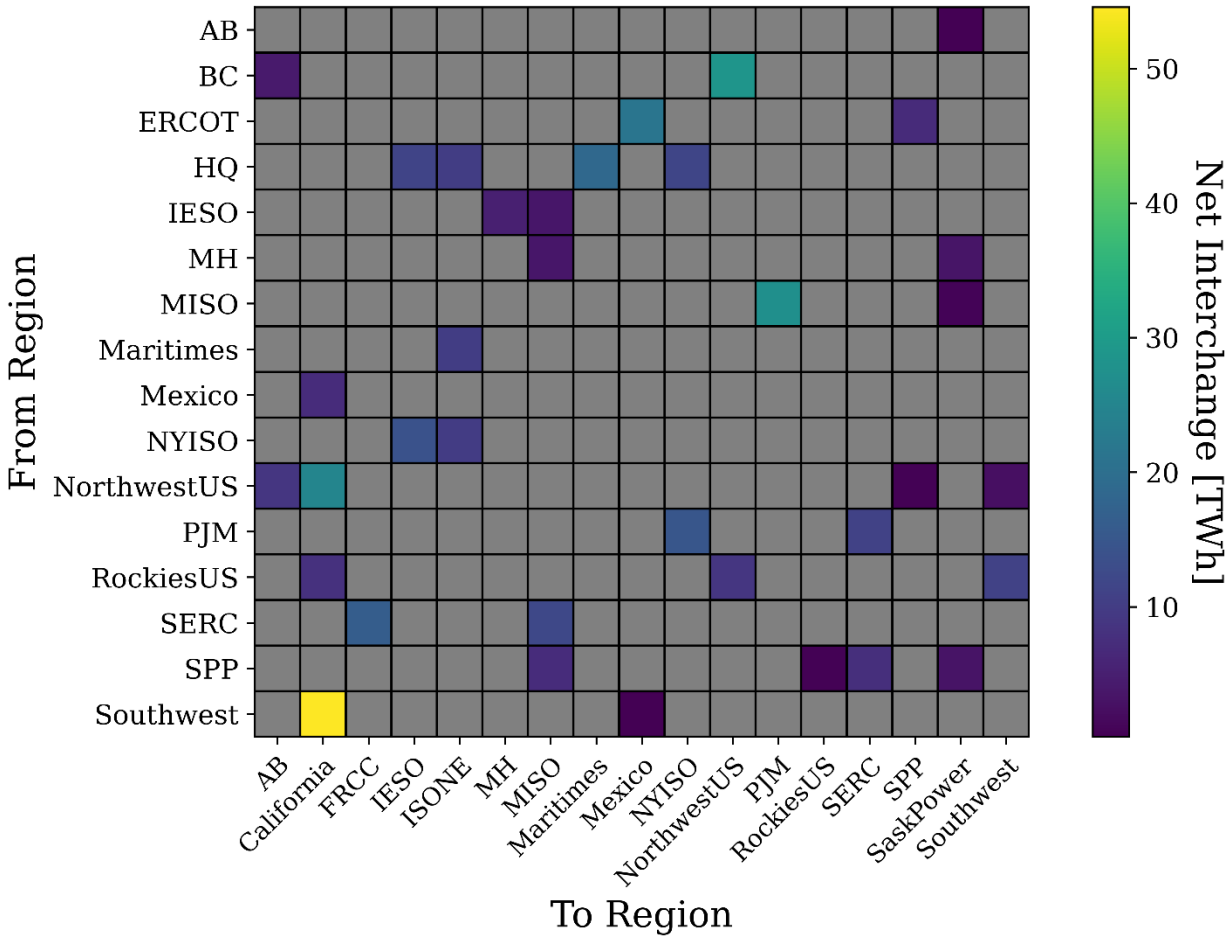

Figure 40. Net interchange between regions and their neighbors over the year (Low Cost VG 2050)

A gray box indicates there is not a connection between the regions (or power is flowing the opposite direction in net).

AB = Alberta
BC = British Columbia
FRCC = Florida Reliability Coordinating Council
HQ = Hydro Quebec
IESO = Independent Electricity System Operator
ISONE = ISO New England
MH = Manitoba Hydro
NYISO = New York Independent System Operator
SPP = Southwest Power Pool

Figure 41 shows the gross interchange patterns between regions. Though many interfaces stand out in both Figure 40 and Figure 41, there are some differences in the figures. Though it is the largest net flow, the flow from the Southwest U.S. to California is not the most significant interface for gross flows, because it flows primarily one way. Other interfaces (particularly between large regions like MISO, SERC, and PJM) flow both directions frequently, and these are more noticeable in gross flow compared to net flow. Gross interchanges are also much larger than net interchanges because of the bidirectional flow on most interfaces, including the MISO/PJM interface. See Figure 42 (page 63) for details about the time series.

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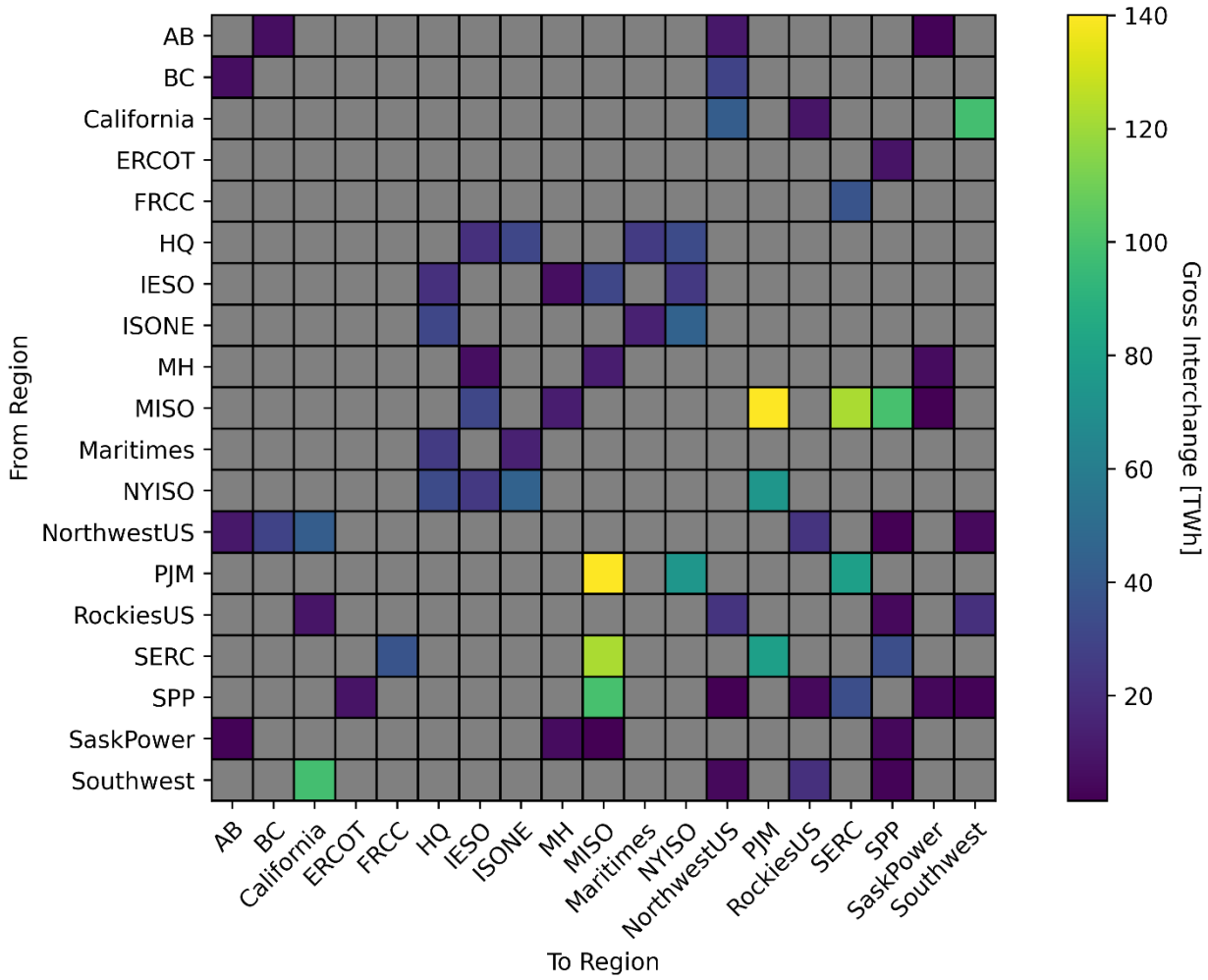

Figure 41. Gross interchange between regions and their neighbors over the year (Low Cost VG 2050)

Figure 42 shows the duration curve of the flow along major transmission interfaces (including both existing transmission and new builds). Flexibly operating transmission interfaces is useful in these scenarios. Many key interfaces have bidirectional utilization, meaning regions can benefit from cooperation by selling or buying power when the economics (and/or adequacy) are favorable. The PJM-NYISO (New York Independent System Operator) interface is expanded in the capacity expansion model, and the lines are used heavily in both directions. It does not have major net flows (Figure 40) but is heavily used in many hours of the year (Figure 42). In this plot, only the British Columbia to Northwest U.S. interface is used primarily in a single direction.

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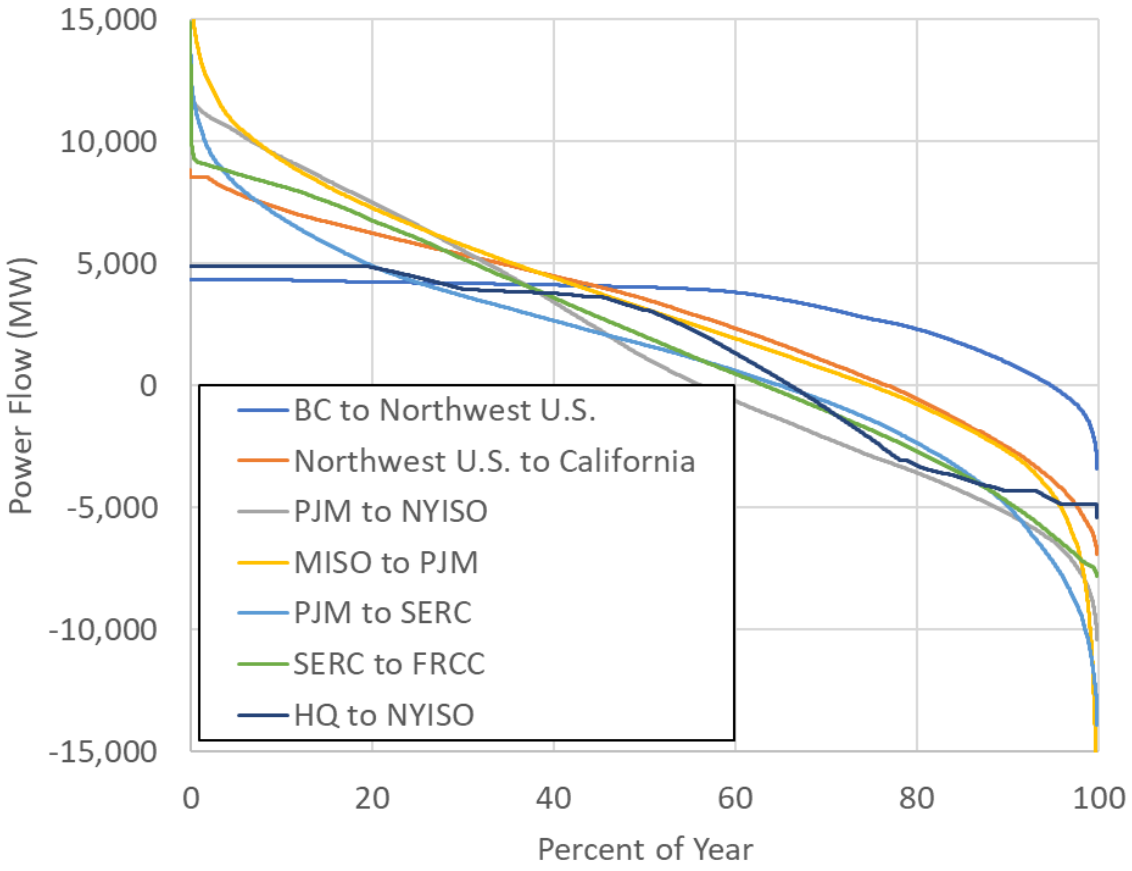

Figure 42. Duration curve of flows along major U.S. interfaces in Low Cost VG 2050

The region name listed first is the source region of the flow and the second name is the destination region. A positive flow means the source region is exporting to the destination region. A negative flow means the destination region is the exporting region.

3.4 System Flexibility

This section provides a general overview of flexibility in the scenarios, and the subsequent sections examine specific technologies.

3.4.1 Operational flexibility comes from transmission, flexible operation of hydropower and thermal resources, storage, and curtailment of wind and solar generation.

Figure 43 through Figure 45 show the dispatch of the three interconnections during a September week with several very high-load days a few low-load days. This period highlights these sources of flexibility in action. During the peak net load hours in the Eastern Interconnection (mostly around sunset), you see imports, storage, hydropower, and thermal generation all dispatching heavily, with thermal generation comprising more than half of the total generation (up to 59%). These hours represent the hours in the far left of the thermal generation duration curve in Section 3.2.3 (Figure 26 through Figure 28). By the late morning on September 8, thermal generation represents only 10% of generation. These are the hours at the far right of the duration curves in Section 3.2.3. Hydropower is also generating significantly less to save power for sunset hours. This flexibility in various technologies helps the grid to balance at high levels of renewable

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contribution. Imports to the Eastern Interconnection are coming mainly from Canada, and the Eastern Interconnections and the Texas Interconnection are not exporting peak load hours (see below). Even during the high-load days, some curtailment of wind and solar generation occurs during midday hours. The curtailment often occurs near peak load in the early afternoon (during high load, high solar output hours), but almost never during the peak net load[33] hour (sunset each day). There is no unserved energy (load curtailment) in the PLEXOS model.

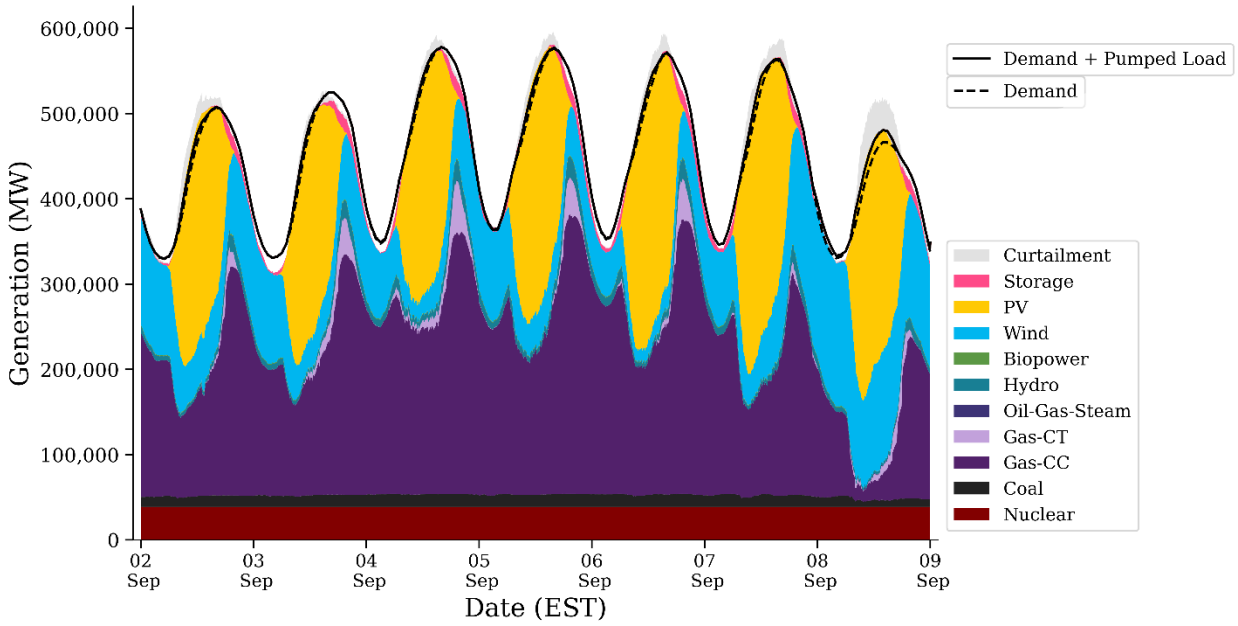

Figure 43. U.S. Eastern Interconnection generation dispatch stack for early September (Low Cost VG 2050)

Figure 44 shows the dispatch in the Western Interconnection during the same period. Many of the same features exist with the Eastern Interconnection but in different proportions (e.g., more hydropower). The U.S. portion of the Western Interconnection is importing from the Canadian portion during this period, and hydropower is contributing heavily in peak net load hours (sunset).

[33] Net load is the load minus available wind and solar generation.

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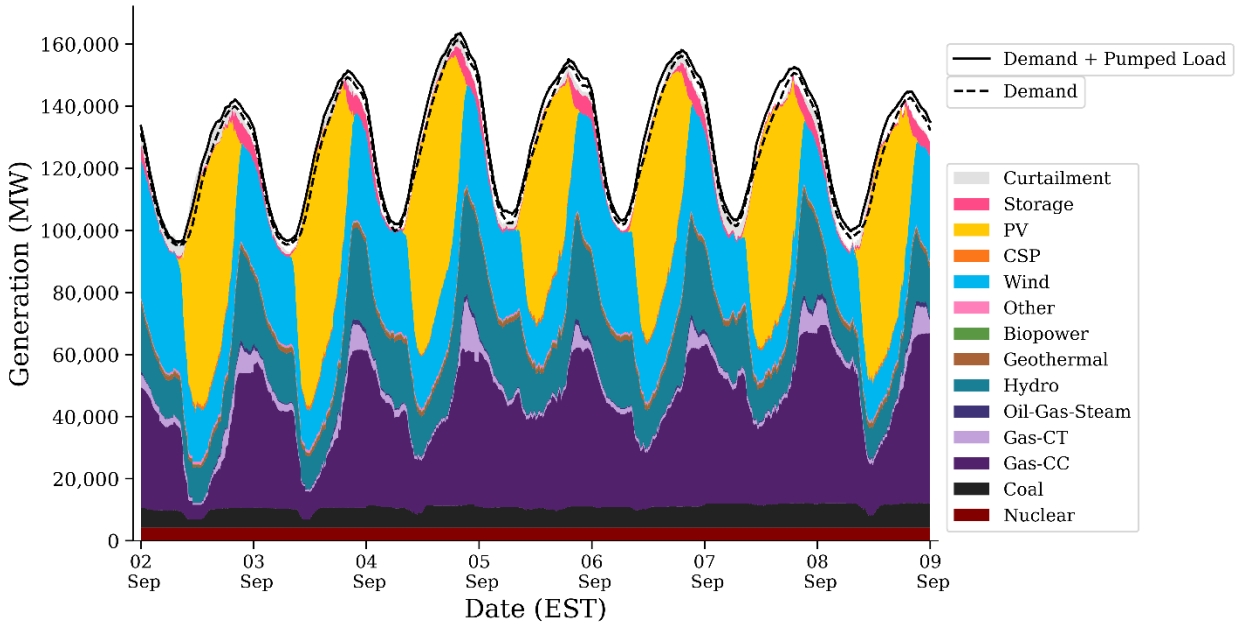

Figure 44. U.S. Western Interconnection generation dispatch stack for early September (Low Cost VG 2050)

Figure 45 shows the Texas Interconnection dispatch during the same week. It has many patterns similar to those in Figure 43 and Figure 44, although curtailment and exporting are seen at night (versus never or during day) and are likely driven by wind and load patterns (i.e., high wind and low load hours). Hydropower plays a minor role in the Texas Interconnection, and the dispatch there is made up entirely of wind, solar, and thermal generators.

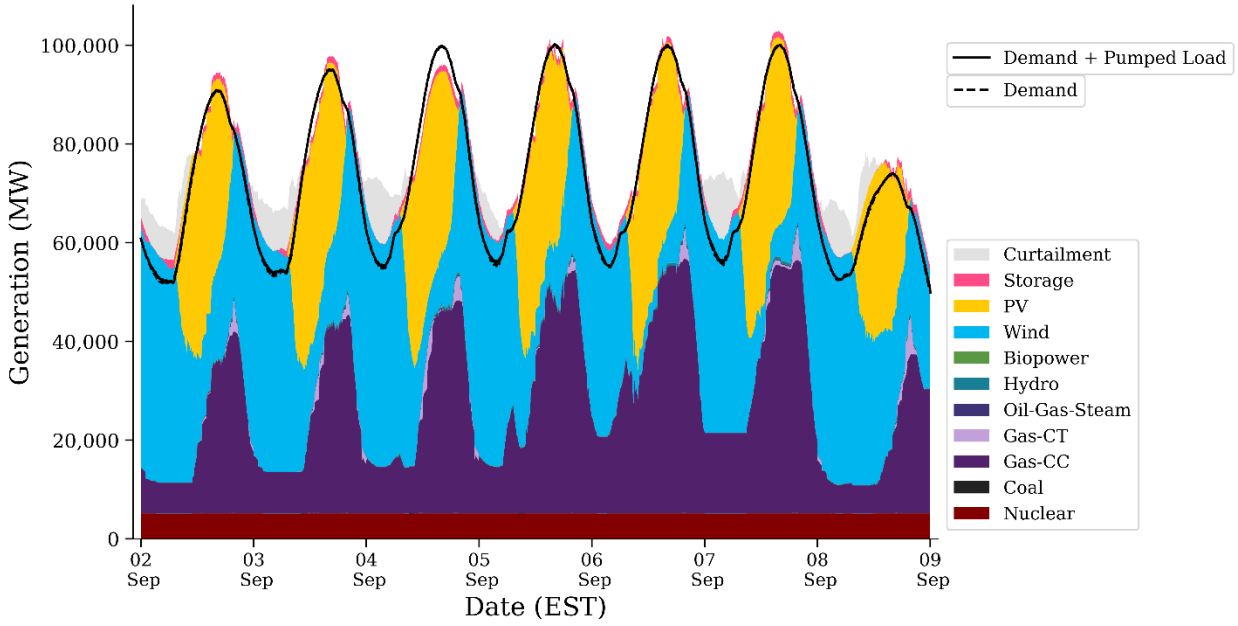

Figure 45. Texas Interconnection generation dispatch stack for early September (LowCost VG 2050)

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3.4.2 Less than 10% of potential wind and solar is curtailed.

Figure 46 shows the duration curve of curtailment in the United States in the Low Cost VG scenario. In total, it represents 9.3% of the potential wind and solar generation in the United States. The bulk of the curtailment occurs in a small percentage of the hours, but curtailment occurs somewhere in the United States in almost every hour. Curtailment represents a trade-off between capital costs of wind and solar (or transmission and storage) compared to fuel costs of thermal generators.

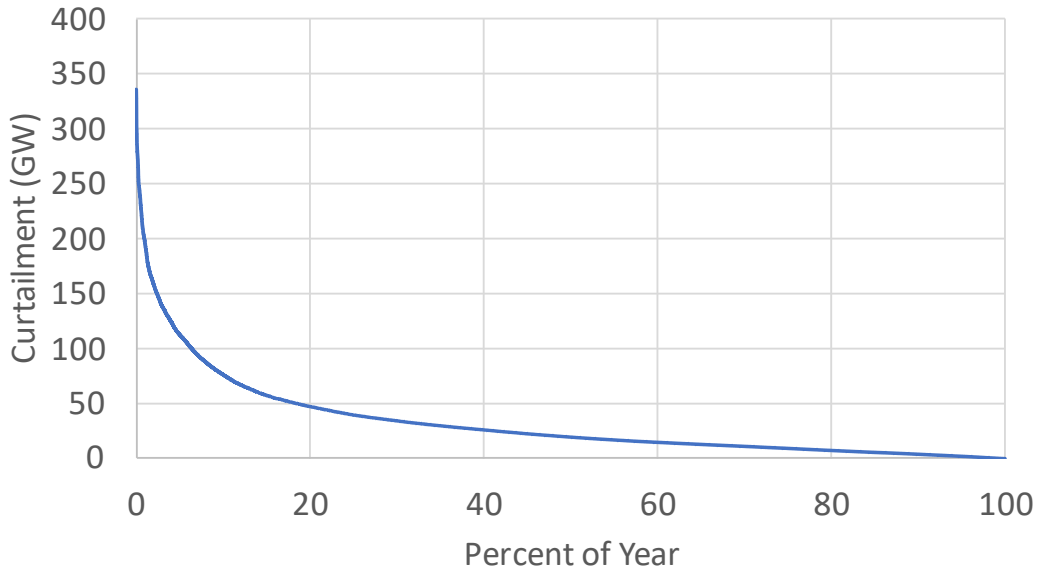

Figure 46. U.S. curtailment duration curve

Figure 47 shows the diurnal and seasonal patterns of curtailment in the United States. Most (but not all) curtailment occurs during the day, following the solar pattern until late afternoon hours, when the curtailment reduces before sunset. Curtailment also peaks in the spring months and is at a minimum in midsummer to late summer.

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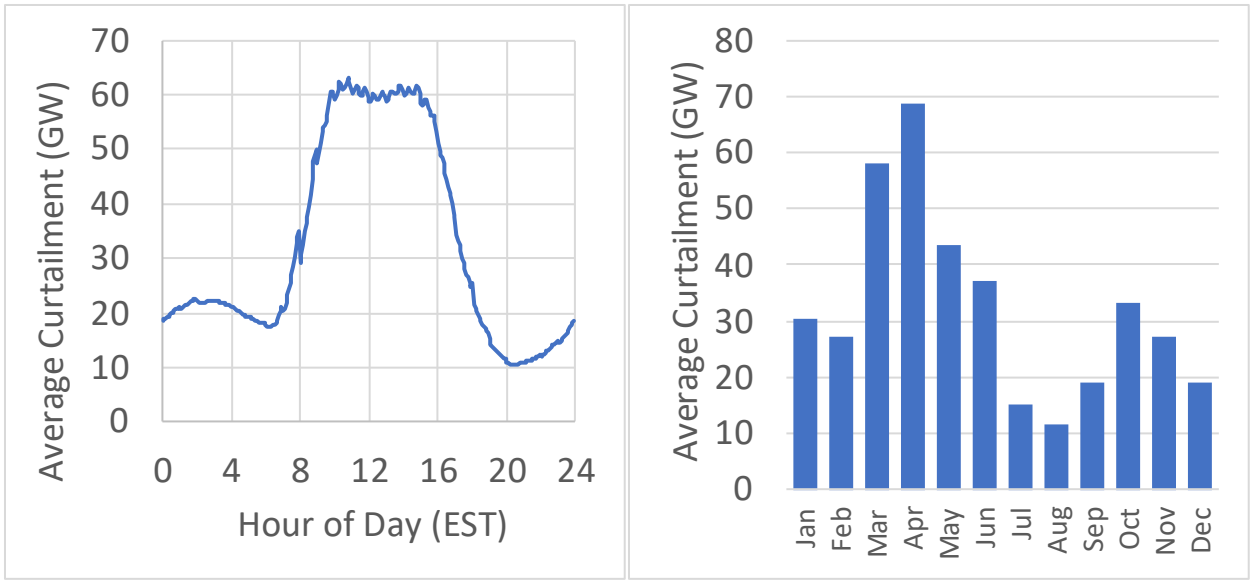

Figure 47. U.S. curtailment duration by hour (left) and month (right)

Figure 48 shows a week of U.S.-wide dispatch during May, a period with lower loads, and high solar and wind generation. Midday hours on May 10 and May 11 show hundreds of gigawatts of curtailment, and the thermal generation (mostly nuclear running flat and gas CCs cycling daily) operates similarly in each day. The curtailment varies widely through the week, but the actual dispatch is fairly consistent. Storage, imports and exports, and hydropower all play key roles, especially regionally, that are explored in Sections 3.3, 3.4, 3.5.

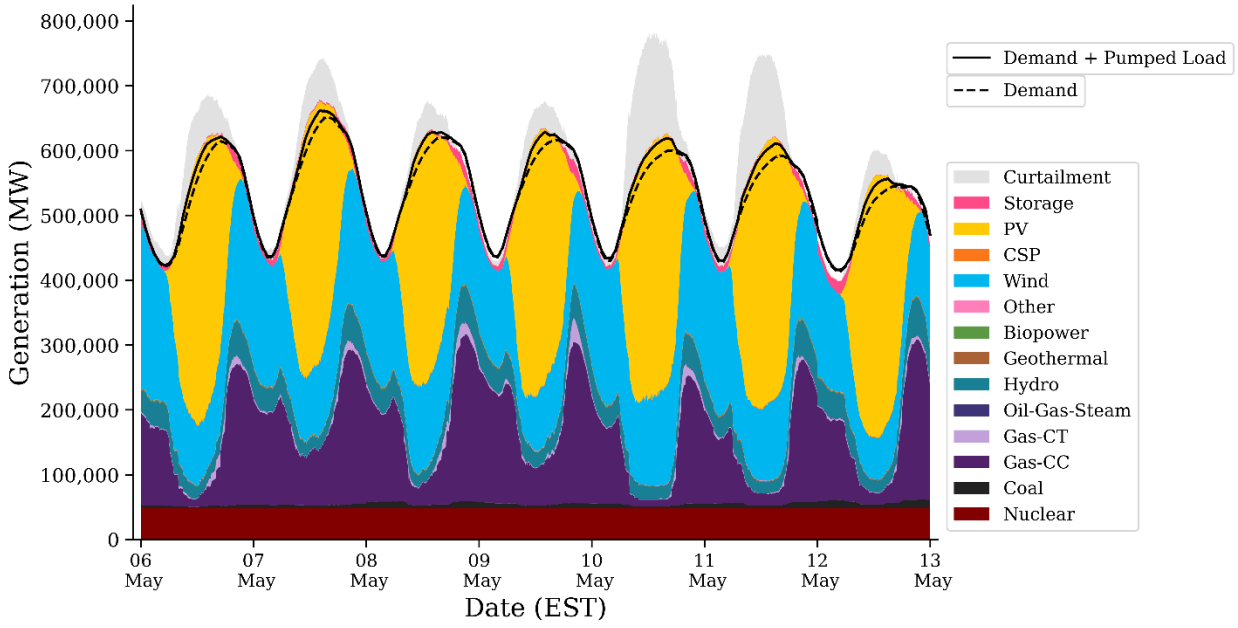

Figure 48. U.S.-wide dispatch stack during a high-curtailment period

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3.4.3 Hydropower contributes significantly to energy, adequacy, and flexibility.

Figure 49 through Figure 51 qualitatively demonstrate the contribution of hydropower flexibility. Figure 49 demonstrates hydro's contribution to the adequacy and flexibility during a week in the Western Interconnection that includes low-load and high-load days. At the peak net load, hydro capacity is contributing more than 30 GW toward the 120 GW net load peak, even in the fall, when overall energy available for hydropower is low. Earlier in the week, when net load peaks are much lower, the hydropower generators are holding back energy for higher load days. This demonstrates the potential for flexible hydropower to generate most when needs are high and least when needs are low in the future grid.[34]

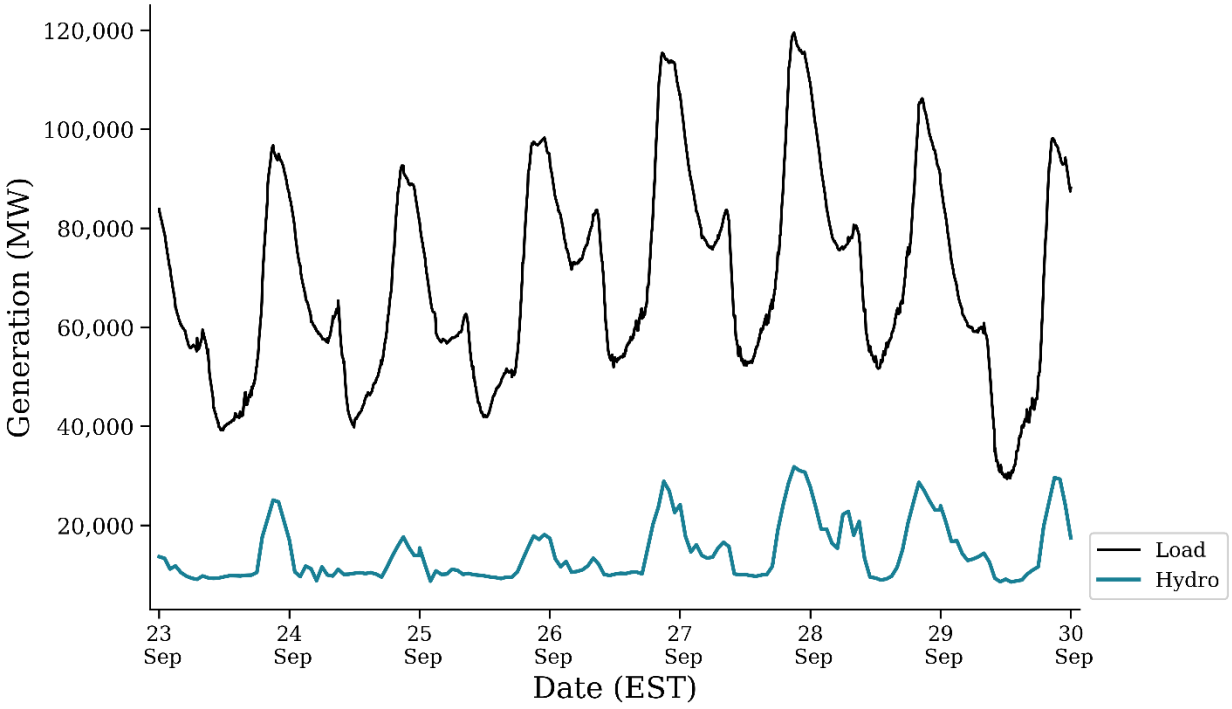

Figure 49. U.S. Western Interconnection hydropower and net load during a week with both high- and low-load days in September in the Low Cost VG 2050 scenario

Although average generation is low during this example of a week in September, the peak generation is much higher and contributes toward adequacy in the high-value periods.

Figure 50 shows the hydropower and net load again during a period in May with high curtailment (the same period shown in the dispatch stack in Figure 48). Average hydropower output is higher during this period despite lower loads than September. This demonstrates some of the seasonal limitations on hydropower flexibility based on the model assumptions (see Section 2.2.3). Some generators throughout the continent (e.g., Quebec) might have some interseasonal flexibility that is not considered here, but these seasonal limitations represent a real constraint on hydropower flexibility for many generators.

[34] This implies some ability to forecast these higher-load days in advance, although the model simplifications in the multiday dispatch prevent an unrealistic amount of information being available in the optimization.

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The hydropower follows diurnal load patterns well in both weeks. In the model dispatch, hydropower contributes during both the larger peaks in net load (which is sunset in Figure 49 and Figure 50) and the smaller peaks that sometimes occur during hours around sunrise. The Eastern Interconnection hydropower dispatch shows some similar patterns, but hydropower makes up a much smaller fraction of the load overall.

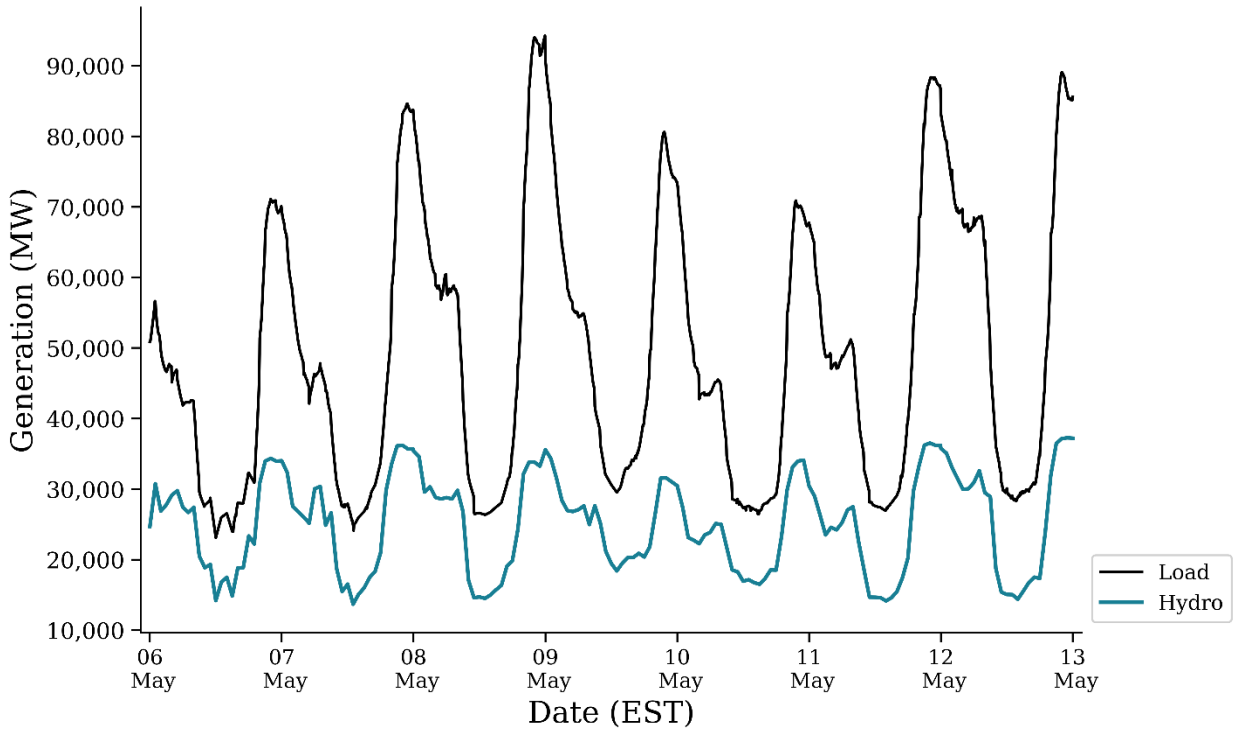

Figure 50 U.S. Western Interconnection hydropower generation and net load during a week with high curtailment

Average generation is significantly higher than during the September week, although the net loads are lower. This seasonal challenge demonstrates a constraint on flexibility, although the hydropower still follows the daily load pattern well, helping contribute in higher-value hours and reduce generation in hours when curtailment is happening the most.

Figure 51 shows the total U.S. net load versus total U.S. hydropower generation for the year. The strong correlation indicates that even with the modeled limitations to flexibility, hydropower generally can contribute substantially when energy production has the most value to the grid (high net load) and reduce generation when it has the least (low net load).

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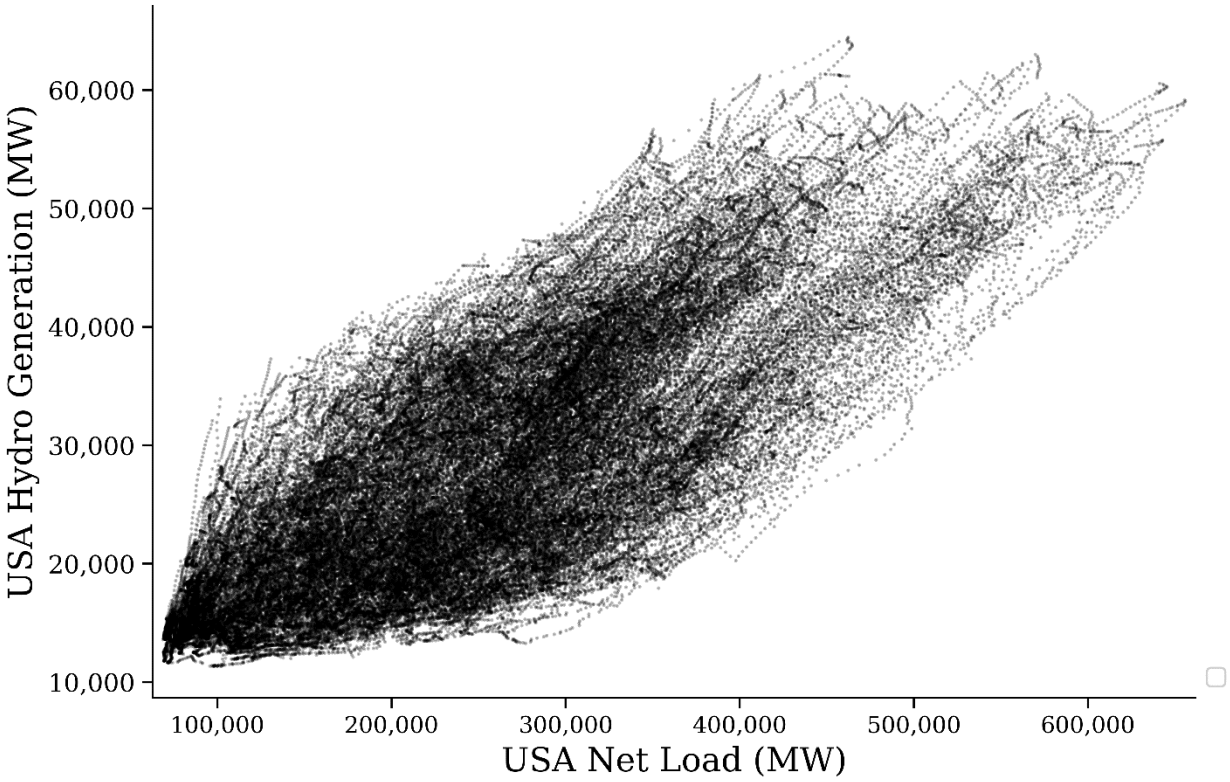

Figure 51 Total U.S. generation versus total U.S. net load for the entire year

Each dot represents a 5-minute interval in the PLEXOS model. The strong correlation indicates that hydropower is following net load patterns well and contributing to adequacy in high-value hours, and is helping reduce curtailment of wind and solar by generating less in low net load hours.

3.4.4 Hydropower flexibility reduces system costs by more than $2 billion per year.

The previous section qualitatively demonstrates some of the value hydropower brings to the system, including generation during times of peak demands and the ability to turn down at other times. To explore these values in quantitatively, we ran the unit commitment and dispatch model again assuming heavily constrained hydropower operations. By comparing the cases, we can understand the value and benefits of hydropower flexibility to this future scenario (Low-Cost VG 2050).

The Low-Cost VG scenario assumed hydropower flexibility intended to represent today's levels of flexibility. The constrained case assumed operations at all hydropower plants (not just run-of-river) have no flexibility (i.e., they have constant output, with the constant output varying monthly or daily based on water flows). Run-of-river plants were modeled with the same time series assumptions (historical flows) in both cases. This case was not intended to represent a realistic future, but to help estimate the benefits that the flexibility of hydropower provides compared to a hypothetical resource that cannot follow load. The key caveat for this valuation is that it is based on the amount of flexibility allowed in the model (see Section 2.2.3). Future work could further refine the representation of hydropower within the model and disaggregate the types of flexibility (e.g., determine how much benefit is from interday versus intraday flexibility).

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Table 10 shows some of the impacts of hydropower flexibility on key metrics in the Low-Cost 2050 production cost modeling. Today's approximate level of hydropower flexibility—compared to a completely inflexible hydropower fleet—could reduce annual operating (production) costs by 3.0%, curtailment by 0.6 percentage points, fossil-fueled generation by 1.6%, and emissions by 1.3%.

Table 10. Benefits of Hydropower Flexibility

Metric	Impact
Cost	Today's level of hydropower flexibility reduces annual operating costs by $2.3 billion, which represents 3.0% of the system production costs.
Curtailment	The flexibility of hydropower to turn down in periods of curtailment and generate more in periods of need reduces curtailment from 9.9% to 9.2%.[a]
Generation	The reduction in curtailment leads to a reduction in generation from fossil-fueled units of 22 TWh (1.6%); this includes an increase in coal generation of 4 TWh and a decrease in gas of 26 TWh.[b]
Emissions	Increased flexibility reduces emissions in this scenario by 1.3%.

These values are based on a comparison of the 5-minute dispatch model runs from the Low-Cost VG scenario with runs from an identical scenario with all hydropower flexibility disabled (i.e., dispatchable hydropower generators are assumed to have flat output levels for each month). U.S. and Canadian hydropower was included in the sensitivity, so results presented are aggregated for the continent.

[a] Curtailment reported here is a U.S. and Canada average, because the sensitivity was done for all U.S. and Canada hydropower.

[b] Because the dispatch of generators is a cost optimization, increased flexibility will lead to selecting lower-cost resources (in this case, coal because of fuel costs)

Figure 52 shows the annual pattern of daily cost reductions from hydropower flexibility. It is smoothed to limit the visibility of interday energy shifting. Although the reasons for the value likely vary by season, the overall value is similar between seasons. Curtailment is likely a strong driver of this value; the highest curtailment in the model and the highest monthly value of hydropower flexibility both occur in April. The lowest curtailment occurs in July and August, as does the lowest monthly value of hydropower flexibility. In high curtailment periods, like the spring, the value comes primarily from avoided curtailment. In low curtailment periods, it comes from a variety of sources, including substituting higher-cost peak generation with lower-cost resources.

From a hydrology perspective, the high-value periods do coincide with low-water times of the year for these modeling assumptions (see Section 2.2.3 for hydropower output by week). This might be due to the ability to shift power more easily when the quantity of water does not require generators to regularly run near capacity. More study of different hydrological conditions mixed with flexibility changes would help address this question.

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Figure 52. Daily cost reduction from hydropower flexibility

This figure shows the smoothed, daily hydropower flexibility cost reduction, which averages $6.3 million per day. It does not substantially vary by season, except a period in early March when the model shifts energy to another time if it is feasible to do so. The smoothing is a 30-day filter, to limit the impacts of daily variability due to substantially more or less energy generation from hydropower.

The above analysis is based on a typical hydropower year for all regions. We also reran the model with a 5% increase (wet) and a 5% decrease (dry) in energy availability at hydropower generators to see the different impacts (no changes were made to the capacity of the generators). The Dry case leads to an increase in production costs of $1.1 billion. Most (27 TWh) of the approximately 35 TWh generation needed to make up for the reduced hydropower generation came from gas CCs, and 5 TWh came from reduced curtailment at wind and solar generators In the Wet case, production costs decrease by $0.9 billion. The additional curtailment from wet conditions is slightly higher than the reduction from wet conditions, and the 7 TWh additional wind and solar curtailment represents approximately 20% of the additional available hydropower energy.

Table 11. Impacts of Different Water Conditions

Metric	Dry	Typical	Wet
Cost, $ billion (change from Typical)	$78.5 billion (+ $1.1 billion)	$77.4 billion	$76.5 billion (- $0.9 billion)
Gas CT, TWh (change from Typical)	95 (+ 1)	94	93 (- 1)
Gas CC, TWh (change from Typical)	1,584 (+ 27)	1,557	1,534 (- 23)
Wind and Solar (TWh difference)	3,492 (+ 5)	3,487	3,480 (-7)

These values are based on comparing the 5-minute dispatch model runs from the Typical case to a Wet (5% additional energy from hydropower in every month) and Dry (5% reduction in energy).

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3.4.5 Hundreds of gigawatts of storage could be installed if costs came down significantly.

In this section, we discuss the impacts of running the ReEDS model with the 2018 ATB Low-Cost assumptions for storage, compared to the Mid-Cost assumptions that were used for the core cases. In the core nonelectrification scenarios (BAU, Low-Cost VG, and CO_2 Constrained), storage capacity in 2050 is 30 GW–55 GW. In the Electrification scenario, storage capacity is noticeably higher at 130 GW. Figure 53 shows the change in capacity in the core scenarios assuming low-cost storage (based on the 2018 ATB). In the nonelectrification scenarios, storage capacity is approximately 200 GW higher by 2050. In the electrification scenario, there is approximately 350 GW of additional storage by 2050. The existing pumped-storage hydropower was modeled in all scenarios and included as storage (not hydropower) in all plots; the new builds in the core and Low Cost Storage scenarios are primarily batteries with 4 hours of storage capacity.

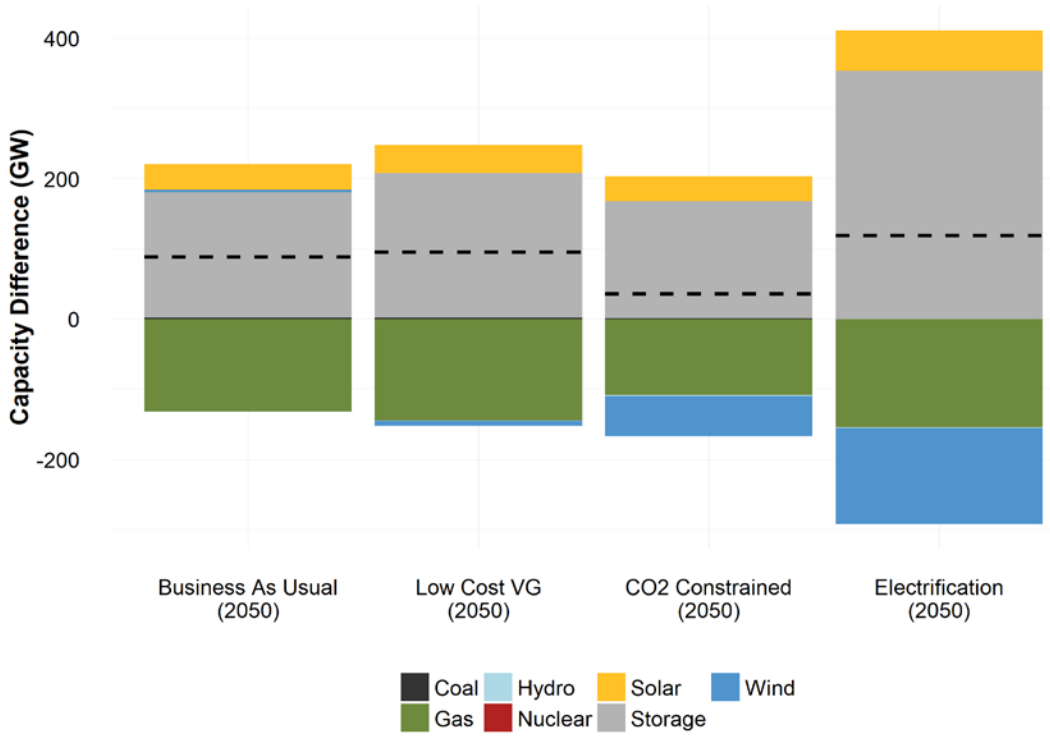

Figure 53. Change in 2050 capacity for core scenarios with lower-cost storage availability

Each core scenario was modeled with standard (2018 NREL ATB Mid Cost) assumptions for storage costs. As a sensitivity, each core scenario was also modeled with lower storage cost trajectories through 2050. The difference between each sensitivity and each core scenario is presented here. The dashed line represents the net capacity impact for each scenario and sensitivity pairing. For all scenarios, the total capacity is higher in the Low Cost Storage cases.

The importance of the contribution of storage to adequacy in these low-cost storage scenarios is shown in Section 3.2.2, where the contribution of renewables plus storage to planning reserve is seen to be hundreds of GW higher in the low-cost storage cases because of the high storage deployment. Deployment of thermal generation (a mixture of gas CCs and CTs) is also several hundred GW less in the low-cost storage scenarios because of the adequacy provided by the storage.

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3.5 Scenario Comparisons

In this section, we compare some of the key outcomes of the scenarios, including costs, emissions, distributed generation, and the impacts of electrification.

3.5.1 Emissions drop substantially in all scenarios.

Figure 54 shows the emissions trajectory through 2050 in the core scenarios. Existing state renewable portfolio standards and clean energy standards drive CO_2 reductions through 2028. The carbon limits in the model (80% reduction by 2050 in the CO_2 Constrained and Electrification cases) are binding starting in the late 2020s. Emissions reductions from the electrification of additional energy end uses in the Electrification scenarios are not considered in this plot, so the Electrification scenario could be part of much larger emissions reduction in the overall energy system. In the Electrification Futures Study, nonelectric sector emissions reductions that were enabled by the newly electrified end uses were approximately 1,500 million metric tons per year in 2050, which is more than the electric sector emissions reductions shown here in any of the scenarios between 2020 and 2050. Between 2030 and 2040, the Low-Cost VG trajectory has significantly lower emissions than the CO_2 Constrained. However, they are nearly identical by 2050.

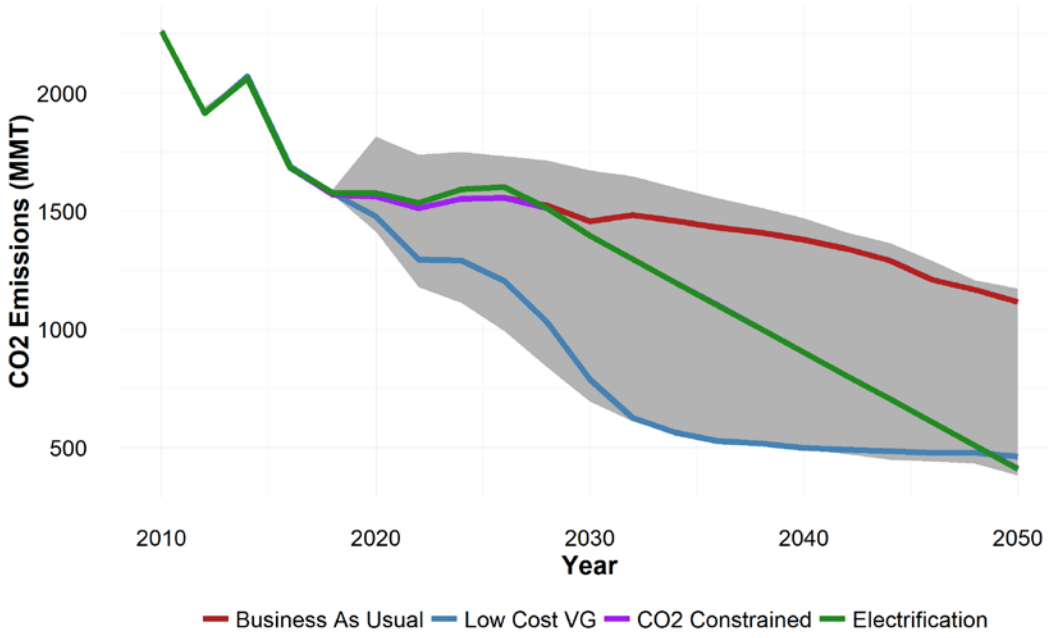

Figure 54. U.S. CO_2 trajectory through 2050 in the core scenarios

The emissions reductions from the electrification of energy end uses (e.g., transportation and heating) in the Electrification scenario are not considered in this plot. The CO_2 Constrained and Electrification scenarios follow an identical trajectory after 2028 because of binding carbon constraints.

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3.5.2 Distributed generation is likely to play a significant role in generation; costs strongly impact adoption.

The dGen modeling results for the United States are primarily drawn from the results of the *2018 Standard Scenarios Report* (Cole et al. 2018). This analysis examines the geographic distribution of DPV deployment across the United States over three cost scenarios as explained in Section 2.1.2.

The installed cost of distributed solar PV is the most significant factor affecting cumulative solar adoption. Based on the three ATB cost projections described in Section 2.1.2, Figure 55 displays dGen's cumulative DPV deployment forecast by scenario. In the High Cost scenario, adoption climbs slowly from 28.2 GW in 2030 to 32.3 in 2050. This slow growth is unsurprising, as the cost of solar remains consistent at 2018 levels in the High Cost scenario, leading to a stagnant market once the least-cost agents have adopted. In the Mid-Cost scenario, adoption increases to 57.3 GW in 2030 and 116.2 GW in 2050. Despite this growth, adoption is still concentrated in the residential sector (91.9 GW). In the Low Cost scenario, some 83.1 GW are adopted by 2030 and this grows to 232.6 GW by 2050. In this scenario, the commercial sector sees significant growth (55.9 GW by 2050) as payback periods are achieved that can compete with the generally lower-cost electricity purchased by commercial businesses.

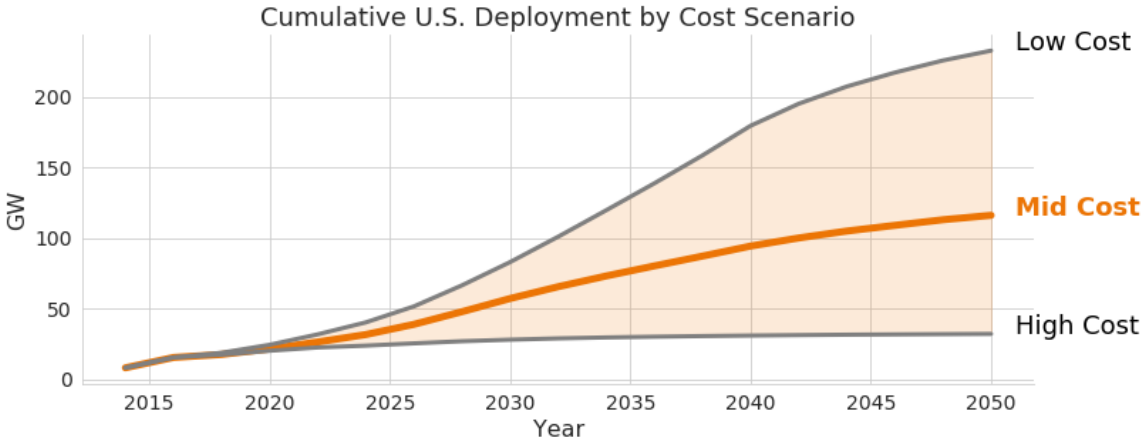

Figure 55. Cumulative U.S. DPV deployment by cost scenario

Differences in adoption levels between geographies can also be explained by *policies* (including tariffs such as NEM, subsidies, and other incentives) and *resource quality* (as measured by global horizontal solar irradiance). Resource quality influences the differences in the capacity factor that comparable PV systems would be able to produce, as displayed in the solar resource map included in Figure 1. The differences from policies and resource are explored in Table 12 (page 76) and Figure 56 (page 77).

Table 12 provides a heat map of the temporal and geographic trends of adoption within U.S. regions. Adoption is considerably concentrated in only a few regions, with 24% of 2050 adoption concentrated in only two regions, and 51% concentrated in the top five regions (for the Mid Cost NEM scenario). The coasts dominate rooftop solar adoption, including the service areas for system operators in the Middle Atlantic (PJM), Florida (Florida Reliability Coordinating Council, or FRCC), the Southeast (SERC-E), and California. Some of this is likely due in part to higher resource quality in these areas (e.g., Florida versus New York). Also, strong state policy

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support or comparatively expensive retail electricity costs boost adoption in New England (ISO-NE), which otherwise has lower solar resource quality. Table 12 also shows the impact of extending NEM policies that do not have a legislated end date (the net metering cases), compared to assuming all regions transition to a tariff where electricity sold to the grid is compensated at wholesale rates (net billing).

Table 12. Cumulative Adoption (GW) in 2050 by Region for Cost and Policy Sensitivities

Region	Low Cost		Mid Cost	
	Net Metering[a]	Net Billing[a]	Net Metering[a]	Net Billing[a]
PJM-E	26.7	19.4	14.1	8.2
FRCC	28.1	10.3	14.1	3.7
SERC-E	19.0	13.8	12.2	5.8
CA	22.0	22.1	10.8	10.8
ISO-NE	14.0	10.3	8.5	4.8
PJM-W	18.0	13.6	8.5	4.5
MISO-E	17.6	9.8	8.5	3.0
NWPP-NW[b]	11.9	8.5	6.6	2.9
SPP[c]	13.1	7.1	5.5	1.9
MISO-S	10.3	6.1	4.9	1.5
ERCOT	14.7	14.7	4.7	4.7
SRSG[d]	6.8	5.5	3.6	2.7
MISO-W	8.4	2.8	3.5	0.8
RMRG[e]	4.6	1.7	2.6	0.8
NYISO	5.2	5.2	2.5	2.5
NWPP-S[b]	3.7	3.2	2.4	2.1
SERC-SE	5.0	3.8	2.0	1.2
SERC-N	3.2	3.1	1.2	1.0
Total	**233**	**161**	**116**	**63**

[a] Net metering assumes state NEM policies that do not have a legislated end date are extended, while net billing assumes all regions use a policy that compensates customers at wholesale rates for power sold back to the grid.

[b] NPP-NW = Northwest Power Pool-Northwest; NPP-S = Northwest Power Pool-South

[c] SPP = Southwest Power Pool

[d] SRSG = Southwest Reserve Sharing Group

[e] RMRG = Rocky Mountain Reserve Group

Figure 56 is a county-level map of the United States indicating the projected cumulative DPV installed capacity by the year 2040 from dGen's Mid Cost scenario (with net metering). The scenario shown in Figure 56 assumes policies such as incentives or NEM programs will continue until current statues expire (as of November 2018). These policies likely explain some of the adoption in Northeastern U.S. states such as New York, Pennsylvania, and Massachusetts, which are expected to see substantial growth through 2040. On the other hand, states like Florida, and Arizona see high levels of adoption likely because of high solar resource availability. California

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and North Carolina both benefit from both a favorable policy regime and substantial solar resource availability.

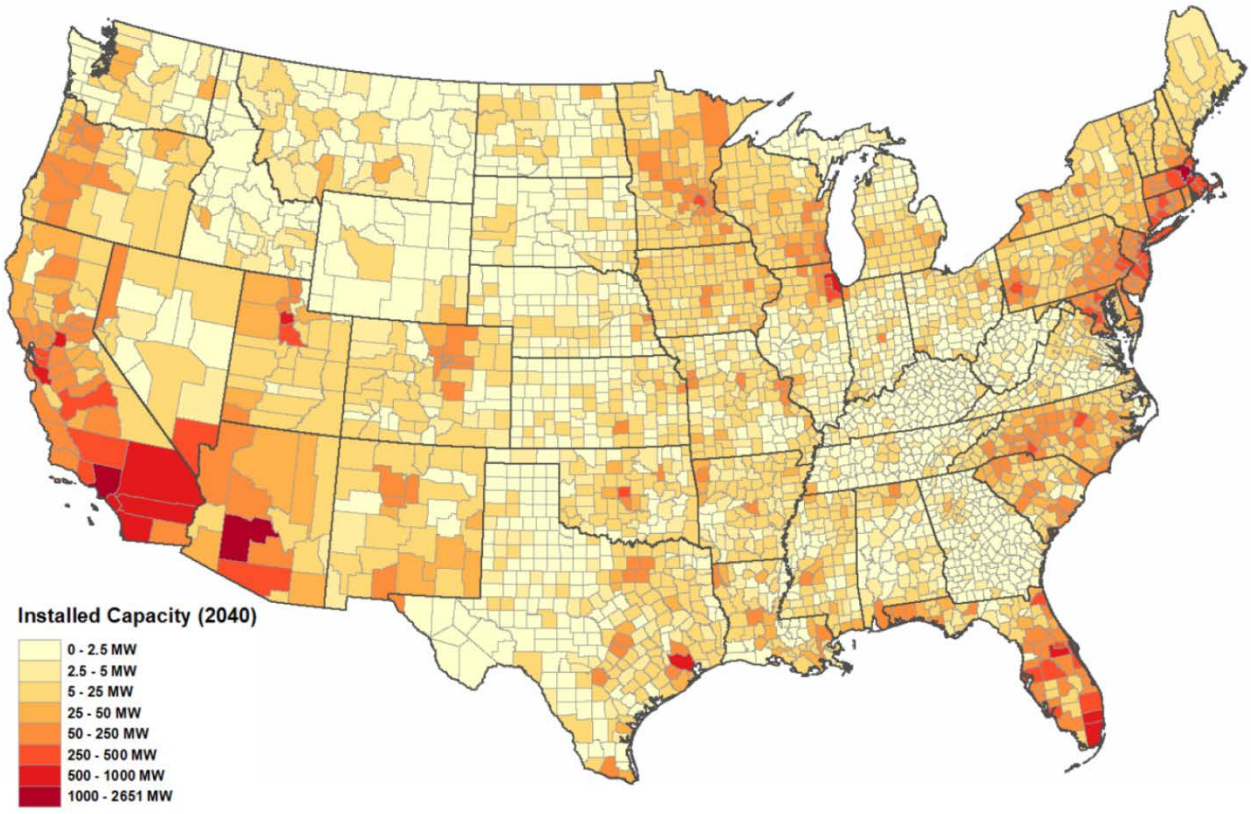

Figure 56. Projected DPV installed capacity (Mid Cost Scenario) by county

Across all geographies, solar resource adoption is temporally linked to factors such as the (increasing) cost of electricity and the (decreasing) installed technology cost of solar. Figure 57 shows a distribution of retail electricity consumption in North America by sector and cost (average $/kWh inclusive of all fees paid by dGen agents). In the United States, the residential sector forms a normal curve with a mean electricity cost of around $0.11/kWh in 2018 dollars. Commercial agents in the model pay somewhat less on average, although there is some bifurcation with bookends between $0.03/kWh and $0.15/kWh. Industrial agents pay substantially less on average, which indicates residential and commercial agents provide some level of cross-subsidization to support industry within the United States through retail rates. This pattern makes the economics of rooftop solar PV adoption more favorable among the residential sector by potentially offering a lower-cost source of electricity as the cost of solar decreases (installed costs per kilowatt were displayed earlier in Figure 9). All these rates are adjusted into the future based on electricity cost projections in the ReEDS model in the iterative process described in Section 2.1.2.

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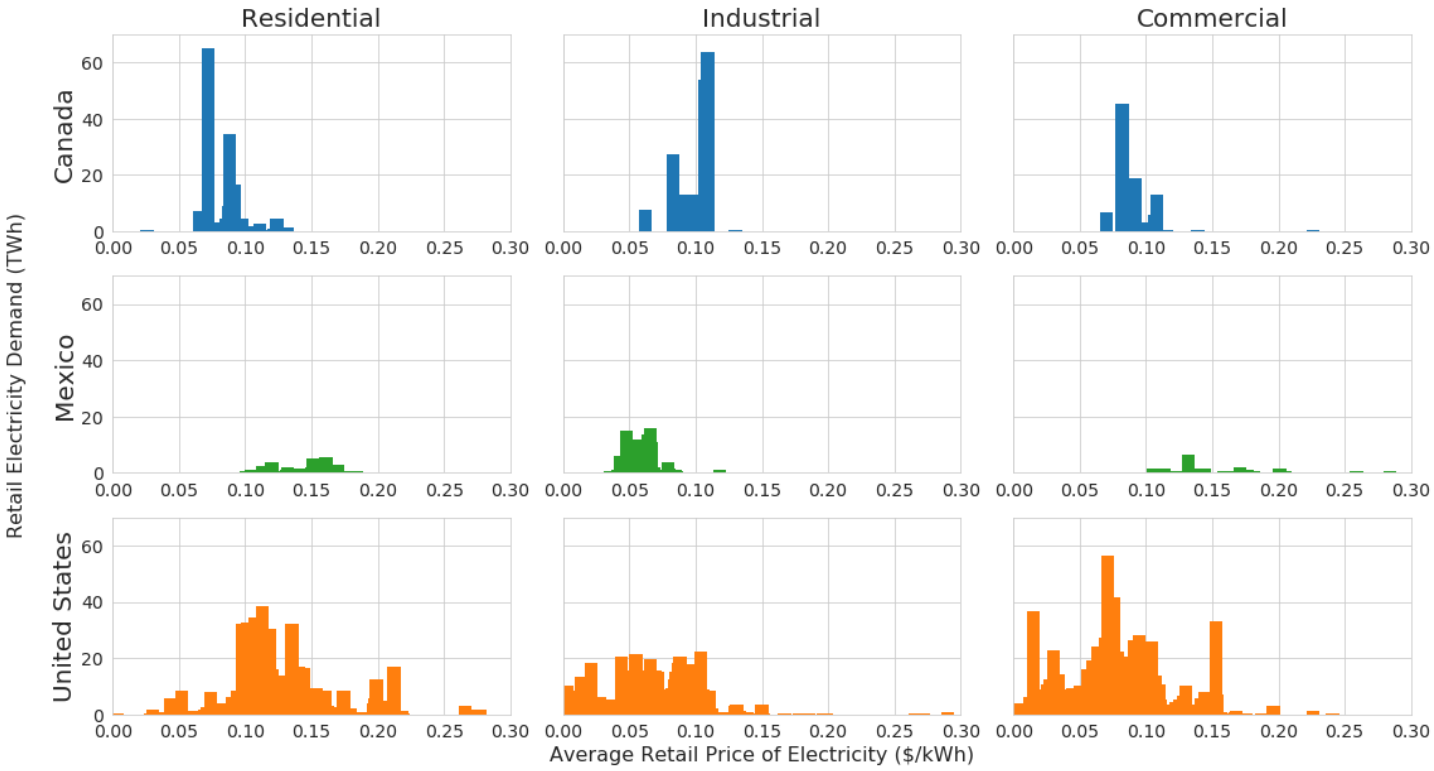

Figure 57. Histograms of average retail cost of electricity ($/kWh) across United States by sector

Histogram bins are weighted based on total load, with rates based on the total charges (including, for example, any metering charges or demand charges) divided by total load. Data were populated in the Utility Rate Database (OpenEI, https://openei.org/wiki/Utility_Rate_Database); see the database for individual sources.

As the cost of electricity increases (modeled as an escalation within dGen, based on iteration with the ReEDS model) and the cost of solar decreases (in the Mid-Cost and Low-Cost scenarios of the ATB), the payback period of adopting DPV decreases. The payback period indicates the number of years of system operation needed to pay for financed system cost through retail electricity bill savings. Because of their higher average electricity cost in the United States, the residential sector achieves lower payback periods than other sectors as displayed in Figure 58 averaging 8.3 years across the United States in 2050 compared with 14.4 in the commercial sector and 15.5 in the industrial sector. As with adoption, payback periods vary greatly by geography. SERC-E which covers Georgia offers the lowest payback periods modeled by dGen of 5.8 years by 2050 in the Mid-Cost Scenario. NYISO contains average payback periods of 21.1 years. Though there is a trend in the results for greater adoption per capita in areas with low payback periods, other influences such as peer effects favor some regions over others.

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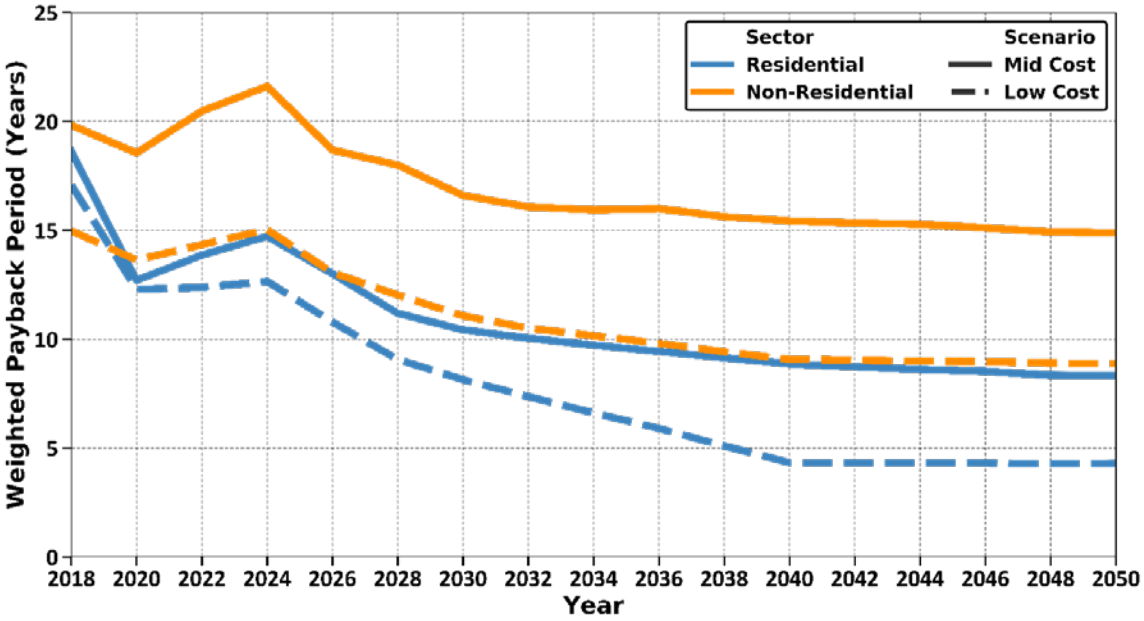

Figure 58. DPV payback periods by year across sectors and scenarios

In conclusion, dGen forecasts 63 GW–233 GW of DPV adoption by 2050 (depending on assumed costs and tariff structures), with the Mid Cost scenario forecasting 116 GW for the net metering case assumptions. Cost is seen to be the most significant factor in determining adoption rates, and factors such as policy regime and resource availability lead to a concentration of adoption in a few regions with lower payback periods for solar PV. The distributed PV adoption is allowed to contribute toward planning reserve and adequacy in the ReEDS and PRAS modeling (respectively), based on the same methods as used for other wind and solar technologies.

The Mid and Low Costs scenarios in dGen (with Net Billing assumptions) were used as inputs for the ReEDS modeling in the NARIS scenarios (Low Cost dGen was used for Low Cost VG scenario, and the Mid Cost dGen was used for all others). Note that there is substantial uncertainty between the cost trajectories.

3.5.3 Total costs are more sensitive to electrification and assumptions about wind and solar costs than carbon limits.

Figure 59 shows the total system costs of the core scenarios through 2050. Comparisons of scenarios depend on several key assumptions—the most important of which are likely the assumed cost of wind and solar generation and the assumed price of natural gas. Based on the standard (2018 ATB) cost assumptions, the carbon constraint (80% reduction from the U.S. grid compared to 2005) leads to a 6% increase in costs. The CO_2 Constrained scenario reduces cumulative continental emissions by 10.5 billion metric tons at an average cost of $39 per metric ton over the 30-year time horizon.

Low-cost wind and solar assumptions lead to overall cost reductions of 16% over the BAU with even lower carbon emissions (through 2050) than the CO_2 Constrained scenario. Although the exact values are sensitive to assumptions, the low-cost wind and solar trajectories consistently lead to higher deployments of wind and solar in NARIS, both in the final scenarios presented here and previous iterations with different cost trajectory assumptions.

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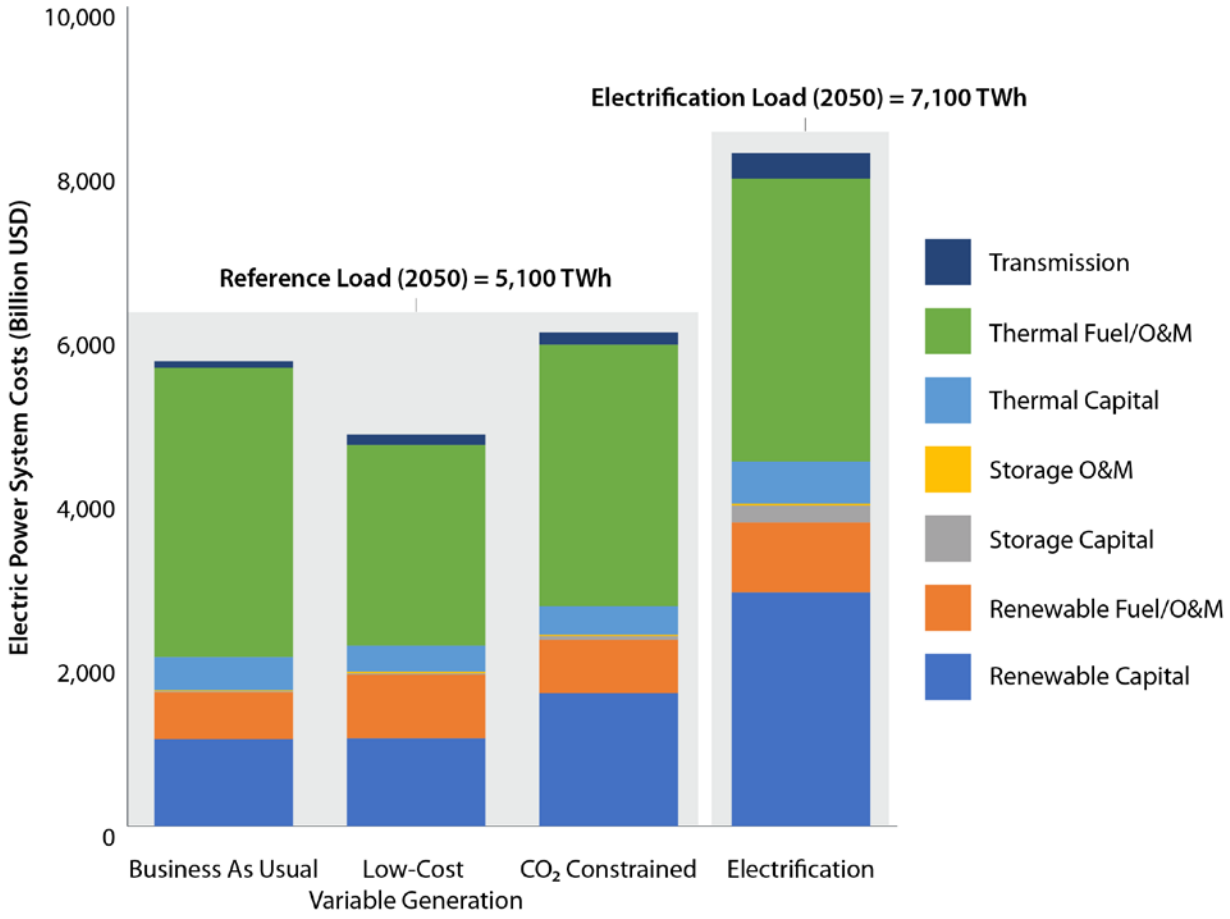

Figure 59. Total U.S. system costs for the core scenarios

The Electrification scenario costs include only electric sector costs and represent a large difference in 2050 demand (2050 annual demand is noted on figure); this does not consider the savings from reducing energy use in other sectors.

3.5.4 Widespread electrification requires approximately doubling infrastructure investment from other core scenarios; further research is needed.

Most of the scenarios in this study assumed load growth consistent with default assumptions that assume minimal newly electrified loads in 2050 (see Section 2.2.2). To understand how key conclusions from the study could change under a high-electrification scenario, we applied the load profiles created for the High Electrification scenario in the Electrification Futures Study for the United States to produce scenarios that assumed higher electrification of existing energy uses, such as transportation and building heating. We used the EnergyPATHWAYS model (using a slightly simpler methodology than the EnergyPATHWAYS used for the Electrification Futures Study) for Canada and Mexico.

EnergyPATHWAYS is a comprehensive energy accounting and analysis framework specifically designed to examine the large-scale energy system transformations. It has been used in more than a dozen national and subnational studies to calculate the impacts of energy system decisions into the future in terms of infrastructure, emissions, and cost impacts to energy consumers and the economy more broadly.

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Projections of future energy service are based on projections of variables that correlate with energy services, such as population. These explanatory variables are referred to as service demand drivers and are exogenous inputs to the EnergyPATHWAYS model. Often a chain of explanatory variables are used to determine service demand in a single subsector. For instance, residential space heating demand is based on residential square footage, which is based on the number of households, which is based on total population. Creation of hourly electricity profiles involves the additional step of multiplying annual final energy by a unitized shape representing the portion of electricity demand that occurs in each hour of the year.

Figure 60 and Figure 61 show the projected load growth from electrification through time and by province respectively. Electrification could add 38% to U.S. load in 2050, with transportation comprising the largest share of the new demands. Generally regional distribution of electrification load growth is similar to regional distribution of load, although some regions will see significant changes to the patterns of electricity load growth. For example, regions in the Northeastern United States could shift from summer peaking to winter peaking (see Figure 61).

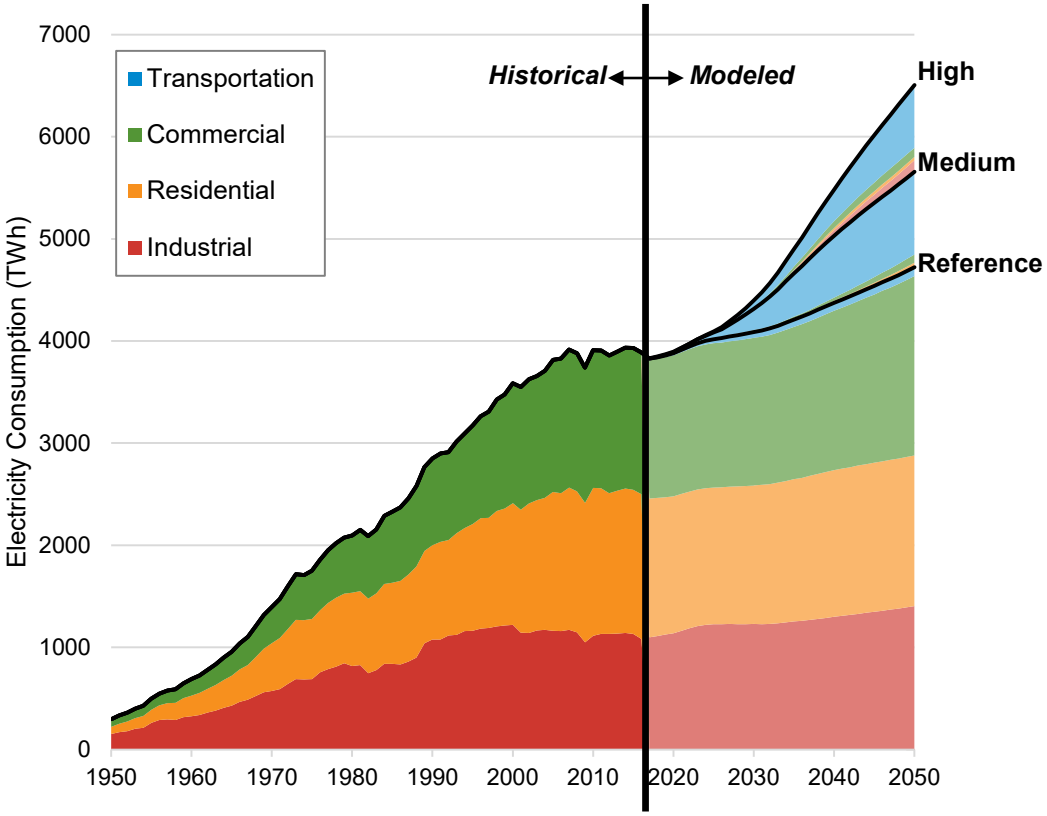

Figure 60. Load growth due to additional electrification in the Electrification scenario

The total load growth from electrification, shown here by sector, represents a 38% increase over the reference case in 2050. Source: Electrification Futures Study (Mai et al. 2018).

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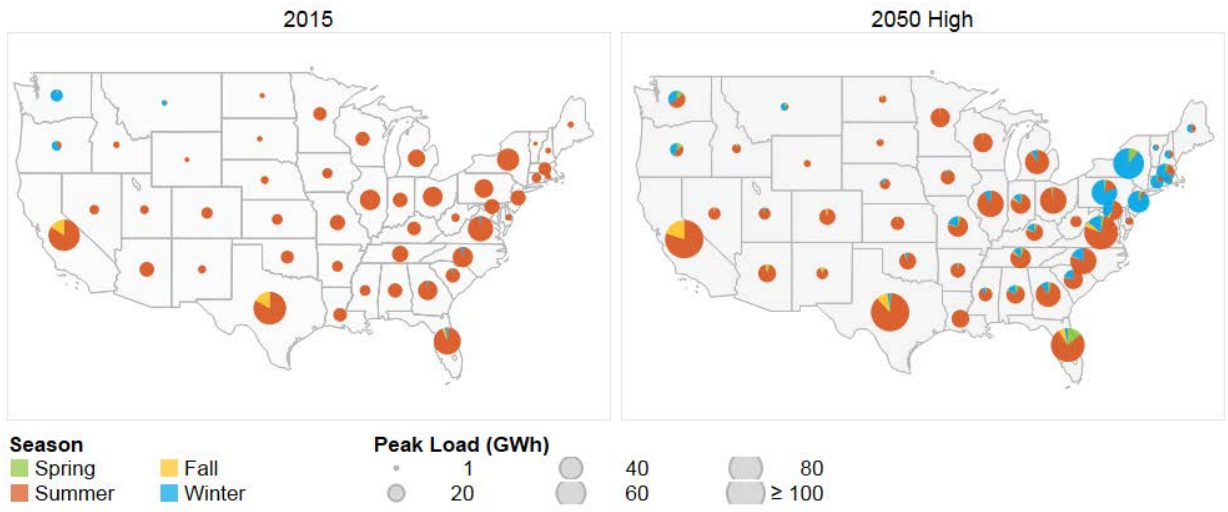

Figure 61. Electrification by state in 2050

The size of a pie charts corresponds with total electricity demand (GW) during the top demand hour. The pie wedges show the seasonal distribution of the top 100 hours with the highest demand by state. Seasons are defined along monthly groupings: summer includes June, July, and August; fall includes September, October, and November; winter includes December, January, and February; and spring includes March, April, and May. Data shown, including 2015 data, are based on modeled estimates from the Electrification Futures Study.

Figure 62 (page 83) shows the generation (left) and transmission (right) infrastructure built in the Electrification scenario versus the CO_2 Constrained scenario, which is the next closest scenario in terms of infrastructure built in the model. Wind and solar development, and transmission development, are approximately double in the Electrification scenario. Though the benefits of electrification (possibly including both economics and emissions) might justify the investment, the quantity of infrastructure development is notable when compared to the other scenarios.

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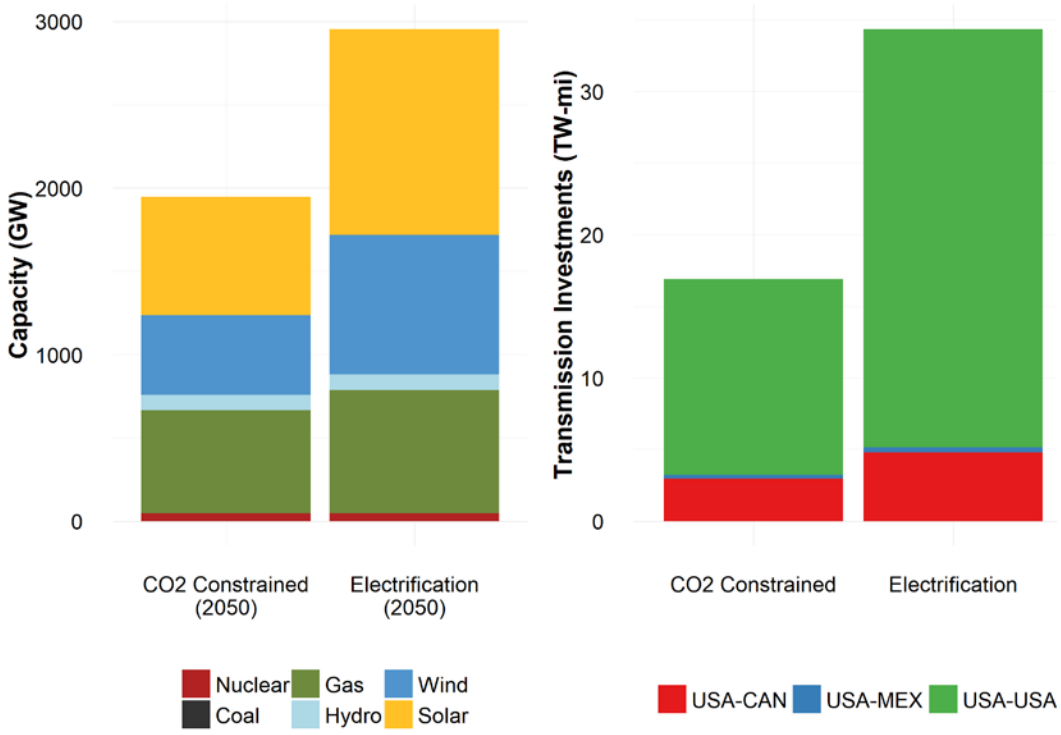

Figure 62. Generation capacity difference in 2050 (left) and total new transmission builds (right) between CO_2 Constrained and Electrification scenarios

The ReEDS model results for the Electrification scenario look similar to those for other scenarios in many respects, with one very substantial difference: the amount of infrastructure built in the Electrification scenario is much larger because of higher loads.

These results are from the ReEDS model; PLEXOS and PRAS were not run on any scenarios that included electrification. Studying demand flexibility in PLEXOS and PRAS could lead to conclusions that reduce infrastructure needs (due to lower planning reserve requirements if peak demands are more flexible) or increase infrastructure needs (if nodal powerflow analysis demonstrates that more intrazonal transmission is needed).

Outside of the general infrastructure builds and costs (which occur due to shifting infrastructure and costs to the electricity sector), the results from the Electrification scenario do not conflict with other scenarios on any key findings (including findings related to transmission value, exports, achieving low-carbon targets, and others). Methods recently developed for the Electrification Futures Study and other studies could help improve methods for treatment of these new, potentially flexible loads. In future work, the value of load flexibility can be addressed.

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3.5.5 Using better information during unit commitment reduces costs and curtailment.

There is significant uncertainty about both (1) what the quality of wind and solar forecasts will look like in 2050 and (2) when commitment decisions will be made in regions both with and without ISOs. To address this uncertainty, we made three different types of forecasts and ran the PLEXOS unit commitment and dispatch modeling with each in the geographically decomposed method described in Section 2.1.3. Forecast data are described in Section 2.2.1.

A system operator in the 2050 grid could use better information during unit commitment in two ways:

- **Improvements in Wind and Solar Forecasting:** Advanced site-specific forecasting techniques were not specifically applied for NARIS, but such techniques could help achieve better information for use by operators in unit commitment.
- **Shorter-Term Commitment Horizons:** Though system operators today make many unit commitment decisions in the day-ahead time-frame, the U.S. grid in the NARIS 2050 scenarios consists mostly of generators that do not need commitment decisions to be made 24 hours in advance. Improved information could be used during unit commitment by performing operational commitment closer to real-time and repeating the process regularly. Such a "rolling" unit commitment method, in combination with generators that are flexible enough to adjust, could incorporate better information.

The model runs presented in Table 13 do not assume any specific rolling commitment horizon or forecasting technique; they use improved forecast information (from "blending" with real-time actual generation) to understand the potential benefit of using better information during unit commitment. Improving forecast error from 10% average MAE to 5%–0% reduces production costs by approximately $1 billion (1%) per step and reduces curtailment by approximately one percentage point per step.

Table 13. Continent-Wide Cost Impacts of Forecast Quality Used During Unit Commitment

Forecast	Annual Production Cost Increase ($)	Annual Production Cost Increase (%)	Total Wind and Solar Curtailment (%)
Perfect forecasts	N/A	N/A	9.1%
Forecast with 5% continental MAE (hours-ahead)	$800 million	1.1%	10.4%
Forecast with 10% continental MAE (day-ahead)	$2 billion	2.8%	11.1%

Forecasts were created using day-ahead model runs from the ECMWF model, time synchronous with the 2012 meteorology presented in this report for dispatch. The forecast with 5% plant-averaged MAE is used in other sections of this report. Note that these sensitivities are based on a penultimate hourly version of the model, and absolute numbers may not be consistent with other sections.

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4 Discussion and Future Work

This report represents the findings of NARIS from a U.S. perspective. However, the overarching conclusions are nearly identical across the continent.[35] Key NARIS learnings for the United States include:

- Supply can balance with demand in a variety of scenarios, with high contributions coming from renewable resources continentally. This was demonstrated through unit commitment and dispatch modeling with nodal transmission representation for 1 year of meteorological data and 7 years of historical meteorology for the Monte Carlo resource adequacy modeling.
- Thermal generators (i.e., nuclear, coal, and gas) do not produce as much energy in the NARIS scenarios in 2050 as actual thermal generators produce today, but significant thermal capacity remains in the NARIS scenarios to serve capacity adequacy needs of the system. This result is economic from a system cost perspective, but more study is needed to understand the market implications. Increased transmission and storage could also fulfill some of these system roles, and they could be optimal depending on cost and emissions limit assumptions.
- Transmission helps enable economics and reliability (via resource adequacy) in the NARIS scenarios. Transmission expansion and cooperation between countries can save the system tens of billions of dollars, while transmission and cooperation between regions can save hundreds of billions of dollars.
- Flexibility to accommodate the variability in the system can come from flexible operation of hydropower and thermal generators, transmission, storage, curtailment, and other technologies and practices.

Key assumptions and limitations of the study, which are listed in Section □, include that:

- The ReEDS model used to create the transmission and generation expansion scenarios performs a cost optimization. Though this helps illuminate potential low-cost pathways to a reliable grid, it should not be read as a blueprint for the continent or any specific region.
- We ran scenarios with various assumptions about wind and solar costs, storage costs, natural gas prices, and other assumptions, and many of the conclusions in this report are robust to these assumptions. However, we represented only a small fraction of the infinite possibilities of combinations of all potential grid conditions in 2050.
- Although we addressed the adequacy portion of reliability, we did not address voltage or frequency stability in any detail in this work.
- Much of the work is based on meteorological conditions from 2007 through 2013. If these years are not representative of typical conditions in the future, or of certain types of extreme events, there could be gaps in our analysis. Climate change has the potential to lead to meteorological conditions different than what we have studied here.

[35] For our report of the NARIS findings from a Canadian perspective, see *The North American Renewable Integration Study: A Canadian Perspective*, which is available at "North American Renewable Integration Study," NREL, https://www.nrel.gov/analysis/naris.html.

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More study is needed to understand some of the key caveats and questions that remain after this work, including about:

- **Market Implications:** The optimizations in our sequence of models led to very different future operation for thermal generators (particularly natural gas combined cycle units) compared to their current operation. Existing market structures might not create sufficient revenue for these generators.
- **Extreme Events:** The NARIS scenarios were analyzed with state-of-the-art tools for data development and modeling. A variety of extreme meteorological events were considered in the 7 years studied (e.g., storms, heat waves, and polar vortex events). More-detailed analysis of how various technologies perform in extreme events (e.g., wind performance in a hurricane) could improve our understanding of grid reliability with today's infrastructure or the infrastructure of the future.
- **Transmission:** More-detailed transmission and power flow modeling could help us better understand the feasibility of the NARIS scenarios, and the costs and benefits of new transmission investments.
- **Demand**: The uncertainty of electricity demand patterns in the long-term future is significant due to climate change and electrification of other sectors. Building off the Electrification Futures Study, electrification-focused studies can also help refine and quantify the benefits of electrification to other sectors and understand the potential flexibility of new demands. For this study, the more detailed models (production cost and Monte Carlo resource adequacy) were not run on the Electrification scenario.
- **Evolving Technologies:** Technology cost improvements in NARIS sensitivities for storage and distributed generation led to significant increases in their deployment (hundreds of GW for each). Ongoing cost reductions for offshore wind in North America would likely lead to significant deployment increases. Other technology breakthroughs, including long-duration storage, carbon capture, geothermal, and concentrating solar power, could possibly lead to similar deployment expectations. Although the key conclusions in this report may be unaffected by these changes, there may be different conclusions or more efficient (or robust) ways to maintain a reliable low-carbon grid with emerging technologies over the coming decades.

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Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-175
Tri-State and Platte River Request for Rehearing

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January 29, 2026

Via Email

Secretary Chris Wright
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Alex Fitzsimmons, Director
Office of Cybersecurity, Energy Security, and Emergency Response
1000 Independence Avenue, SW
Washington, DC 20585

Re: Craig Station, Order No. 202-25-7

Dear Secretary Wright and Mr. Fitzsimmons:

Pursuant to Section 313(a) of the Federal Power Act,[1] and Section 301(b) of the Department of Energy Organization Act,[2] Tri-State Generation and Transmission Association, Inc., and Platte River Power Authority hereby submit for filing the enclosed request for rehearing and for clarification.

Please contact me if you have any questions.

Respectfully submitted,

/s/ Jennifer Quinn-Barabanov

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[1] 16 U.S.C. § 825*l*(a).

[2] 42 U.S.C. § 7151(b).

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY

In re Craig Order No. 202-25-14	)	Order No. 202-25-14
	)	

REQUEST FOR CLARIFICATION AND FOR REHEARING OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION AND PLATTE RIVER POWER AUTHORITY

TABLE OF CONTENTS

SUMMARY 1
Statement of Issues 3
BACKGROUND 4
A. The Petitioners 4
B. The Craig Generating Station 6
C. Craig Unit 1 8
D. DOE Order No. 202-25-14 9
ARGUMENT 11
I. THE ORDER CONSTITUTES AN UNCOMPENSATED TAKING OF PETITIONERS' PROPERTY INTERESTS 11
A. The Order Constitutes a Physical Taking 12
1. The Order's Direction of Prolonged Operations at Craig Unit 1 Contrary to Petitioners' Plan to Retire the Facility Constitutes a Physical Taking 14
2. The Order Mandates Physical Changes to Petitioners' Property That Constitute a Physical Taking 16
B. DOE's Order Constitutes a Regulatory Taking 19
1. Economic Impact 20
2. Investment-Backed Expectations 21
3. Character of the Taking 23
C. Just Compensation 23
II. THE ORDER DISRUPTS PETITIONERS' RELIABILITY PLAN AND FAILS TO ACCOUNT FOR VIABLE ALTERNATIVES 25
A. The Order Violates Petitioners' Constitutional Due Process Rights and Disrupts Carefully Considered Reliability Planning 26
B. The Order Failed to Consider Reasonable Alternatives 29
C. The Order is Inconsistent with the FPA's Statutory Objectives 32
Conclusion 33

Pursuant to Section 313(a) of the Federal Power Act,[1] and Rule 713 of the Rules and Regulations of the Federal Energy Regulatory Commission (FERC or Commission),[2] and the applicable rules of practice and procedure,[3] Tri-State Generation and Transmission Association, Inc. (Tri-State) and Platte River Power Authority (Platte River) (together, Petitioners) hereby file this Request for Clarification and Rehearing of the Order No. 202-25-14 dated December 30, 2025 (the Order) requiring Petitioners and their co-owners to keep coal-fired Unit 1 of the Craig Generating Station in Craig, Colorado (Craig Unit 1) open and available to operate. Craig Unit 1 was scheduled to shut down by December 31, 2025.[4]

SUMMARY

Petitioners and the Department of Energy (DOE) share the goal of securing reliable and affordable electricity generation assets for their service areas' energy grid, including in the event of an energy emergency. For years, Petitioners have engaged in thorough, deliberate, and industry-leading resource planning to achieve this same end. Petitioners' resource planning ensures that the communities they serve are supported by electricity generation resources sufficient to respond to

[1] 16 U.S.C. § 825l.

[2] 18 C.F.R. § 385.713 (2024).

[3] U.S. Dep't of Energy, DOE Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited Jan. 15, 2026); *see also* 18 C.F.R. §§ 385.214, 385.713.

[4] Petitioners are co-owners of Craig Unit 1, and named recipients of the Order. Under the Commission's rules and regulations they are parties to this proceeding. However, if necessary to give them party status, out of an abundance of caution, Petitioners ask that this filing also be treated as a motion to intervene under Rule 214 of the Commission's Rules and Regulations. Petitioners' position on the Order and the nature of their interest are set forth in detail in this filing.

forecasted extreme weather events and demand growth, relying on coal, gas, dual-fuel, hydropower, solar, wind, and battery assets.

Petitioners will continue to work with DOE and other government agencies to secure reliable, affordable generation portfolios, but submit this request for clarification and rehearing because keeping Craig Unit 1 available to operate will not best meet DOE's goal of securing dispatchable electricity resources in the northwestern United States. Tri-State and Platte River, as member-owned and municipal public utilities, respectively, face unique challenges from the DOE's Order that lead them to file this request. The costs of compliance fall directly on their members and customers, who must now pay to respond to the DOE's finding that utilities in the northwestern United States have "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes," DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). The members and customers must pay those costs even though neither Tri-State nor Platte River are experiencing these shortages and not all the members and customers served by Tri-State and Platte River are located in the region identified by the Order. For example, Tri-State has numerous members in New Mexico and Nebraska. Petitioners have already paid for and planned investments in the generation resources needed to secure reliable and sufficient capacity for their systems. The Order therefore imposes additional costs to Tri-State's membership and the communities served by Platte River.

Petitioners respectfully ask DOE to reconsider the Order and to work with Petitioners to find a more effective and affordable path forward, one that will not

delay retirement of Craig Unit 1. Petitioners continue to stand ready, willing, and able to work cooperatively with DOE and any other federal agencies to address energy emergencies in a manner that minimizes costs, promotes reliability, and complies with the law.

STATEMENT OF ISSUES

Pursuant to Section 313(a), Petitioners request clarification and, in the alternative, rehearing based upon the following issues:

1. By mandating Craig Unit 1's availability to operate and the terms under which it shall operate, and requiring related changes to Petitioners' physical property, the Order constitutes both a physical taking and a regulatory taking. Because the Order does not provide "just compensation" from the government, this is an uncompensated taking in violation of the Fifth Amendment to the United States Constitution. *United States v. Pewee Coal Co.*, 341 U.S. 114, 116 (1951); *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015); *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1011 (1984).

2. Because DOE predicated the Order on long-term concerns, Petitioners were deprived of the process due to them pursuant to the Administrative Procedure Act (APA) and the Federal Power Act (FPA), and the Fifth Amendment to the United States Constitution. This constitutes a violation of Petitioners' due process rights as guaranteed by the Fifth Amendment. *Miller v. Campbell Cnty.*, 945 F.2d 348, 353 (10th Cir. 1991); *Pa. Gas & Water Co. v. FPC*, 427 F.2d 568, 576 (D.C. Cir. 1970).

3. There is a disconnect between the energy reliability concerns described by the Order and the means DOE directs for addressing those concerns as compared to alternatives. DOE, therefore, did not establish that the Order "best meet[s] the emergency and serve[s] the public interest." 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373. It is, therefore, arbitrary and capricious.

4. The Order does not align with the statutory objectives of the Federal Power Act (FPA), because it requires the operation of an uneconomic resource and disrupts ordinary and orderly planning, development, and investment in generation resources. It is, therefore, arbitrary and capricious.

BACKGROUND

A. The Petitioners

Tri-State is a wholesale generation and transmission cooperative operating on a not-for-profit basis with its principal place of business in Westminster, Colorado. Organized and existing pursuant to the Colorado Cooperative Act,[5] Tri-State is a public utility subject to FERC jurisdiction under Part II of the FPA.[6] Tri-State is wholly owned by its electric distribution cooperative and public power district members (Utility Members) and three non-Utility Members (Non-Utility Members)[7] and was formed by its Utility Members for the purpose of providing the Utility Members with wholesale power and transmission services for resale to their retail customers.

Through their participation in the cooperative, the Utility Members serve retail customers across Wyoming, Nebraska, New Mexico, and Colorado. Some, but not all, of the Utility Members and their retail customers are located in the 2024 Western Electricity Coordinating Council (WECC) Northwest region.[8] The retail service territories of Tri-State's Utility Members cover approximately 182,000 square miles and their customers include suburban and rural residences, farms and ranches,

[5] COLO. REV. STAT. § 7-55-101 *et seq.* (2019) (Cooperatives- General); Articles of Incorporation (2020).

[6] *Tri-State Generation and Transmission Ass'n*, 170 FERC ¶ 61,221, at P 37 (2020).

[7] Tri-State's Non-Utility Members are: (i) MIECO, Inc., a wholesale supplier of natural gas in the United States; (ii) Olson's Greenhouses of Colorado, LLC, a grower/distributor of plants throughout the western United States that has a contract to purchase thermal energy from Tri-State; and (iii) Ellgen Ranch Company, which leases property from a Tri-State subsidiary.

[8] The boundaries of this region changed from 2024 to 2025, *see* note 24, *infra*.

and large and small businesses and industries, serving approximately 522,000 retail electric meters. Tri-State's Utility Members are the sole state-certified providers of electric service to retail (residential and business) customers within their designated service territories.

Tri-State owns, directly or indirectly, or controls the output of, various power generation facilities within the Western Area Power Administration's (WAPA) Western Area Colorado Missouri (WACM) balancing authority area, and purchases wholesale power within both the Western and Eastern Interconnections. Among other generation facilities, Tri-State is a partial owner of Craig Unit 1, with a 24% ownership share. Tri-State's generating facilities are included in the Western Power Pool reserve sharing pool. This pool facilitates sharing of generation reserves to be activated during a system emergency, such as loss of a generating unit or transmission line. Tri-State expects to participate in the Southwest Power Pool's (SPP) regional transmission organization, with respect to Tri-State's service in the WACM balancing authority area within the Western Interconnection, beginning in April 2026.

Platte River is a not-for-profit, municipally-owned power utility and joint action agency that generates reliable, financially sustainable, and environmentally responsible electricity for its owner communities of Estes Park, Fort Collins, Longmont, and Loveland, Colorado. Platte River is a political subdivision of the State of Colorado and a government-owned utility under FPA Section 201(f), 16 U.S.C.

§ 824(f). Platte River furnishes cost-of-service wholesale electrical power and energy to its four owner communities.

Platte River is headquartered in Fort Collins, Colorado. At Platte River's main generating facility, Rawhide Energy Station, Platte River has one coal-fired power plant, Unit 1, with a nameplate capacity of 280 megawatts (MW), as well as five natural gas-fired units with a total capacity of 388 MW. Platte River also purchases 297 MW of wind energy and 202 MW of solar energy through long-term power purchase agreements and is a preference customer of WAPA's Colorado River Storage Project and Loveland Area Projects, providing up to 78 MW of hydropower. Platte River is a partial owner of two additional coal-fired units, Craig Units 1 and 2, with an 18% ownership share in the Craig units. Platte River's share of the total net capacity from both Craig units is 151 MW. Platte River also owns and operates an integrated transmission system of high-voltage aerial and underground power lines that deliver electricity to the electric utilities of Platte River's owner communities in Northern Colorado. Like Tri-State, Platte River plans to participate in SPP's regional transmission organization beginning in April 2026.

B. The Craig Generating Station

Craig Generating Station is a three-unit, coal-fired power plant located in Craig, Colorado. Craig Units 1 and 2 were built by and are jointly owned by several utilities through what is known as the Yampa Project. Tri-State operates those two units on behalf of all the co-owners, including Platte River, PacifiCorp, Public Service Company of Colorado, and Salt River Project. Tri-State separately owns and operates

Craig Unit 3. Together, these units are transmission-interconnected to the broader power grid and supply electricity into Western energy markets.

As part of its resource plan to address the long-planned retirement of Craig Unit 1, Tri-State has placed into service the 145 MW Axial Basin generating facility. This facility, approximately 26 miles from the Craig facility, relies on much of the same transmission infrastructure. Absent the retirement of Craig Unit 1, this interconnection faces transmission constraints such that, when Craig Unit 1 remains interconnected and available to operate, Tri-State may be required to curtail output from Axial Basin when all facilities are generating at or near full output due to limited transmission capacity.

As a result of changed market conditions and state and federal requirements, Unit 1 has been scheduled for retirement since 2016, and Units 2 and 3 have been scheduled for retirement since 2020, beginning with Craig Unit 1 by December 31, 2025, followed by Craig Unit 3 by January 1, 2028, and Craig Unit 2 by September 30, 2028. A retirement date for each Craig unit is now specified in Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits.[9] In 2016, Craig Unit 1's retirement date was adopted into what was then Colorado Air Quality Control Commission Regulation No. 3 on Stationary Source Permitting and Air Pollutant Emission Notice Requirements and the Regional Haze State Implementation Plan, the latter of which was approved by EPA in 2018.[10]

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[9] COLO. CODE REGS. 1001-27.

[10] *See Approval and Promulgation of Implementation Plans; Colorado; Regional Haze 5-Year Progress Report State Implementation Plan*, 84 Fed. Reg. 47884 (Sept. 11, 2019); Co. Air Pollution

The Craig units have been fueled primarily by coal from the nearby Colowyo and Trapper mines. The Colowyo Mine has ceased active mining and transitioned to full reclamation, with two pits in final reclamation and the third transitioned to reclamation on October 15, 2025. Similarly, the Trapper Mine plans to cease active mining and convert to site remediation in calendar year 2026. Before the closure of the Colowyo Mine, Tri-State stockpiled sufficient coal to meet Tri-State's projected demand of the Craig Units 2 and 3 through their respective planned retirement dates. Before the Trapper Mine closes, Platte River will have stockpiled sufficient coal to meet its projected demand of the Craig Unit 2 through its planned retirement date.

C. Craig Unit 1

Craig Unit 1 can produce up to 427 MW of electricity and has been running since 1980. Over the last ten years, the operations and maintenance cost (without consideration of coal cost or depreciation expense) to run Craig Unit 1 has averaged $12.99 million annually.[11] By the standards of an older coal plant, Craig Unit 1 has generally provided reliable performance when called upon. However, in the last three years (due primarily to economic factors and some forced outages), Craig Unit 1 has run well below half of its capacity for Petitioners.

Control Div., *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016), https://oitco.hylandcloud.com/POP/DocPop/DocPop.aspx?docid=3303135.

[11] Over the last ten years, the operations and maintenance cost to run Tri-State's share of Craig Unit 1 has averaged $23.9 million annually (inclusive of coal cost and depreciation expense). Over the last ten years, the fixed operations and maintenance cost to run Platte River's share of Craig Unit 1 has averaged roughly $2.3 million (exclusive of coal cost and depreciation expense) annually.

Operation and maintenance of Craig Unit 1 has been undertaken prudently to reflect the scheduled 2025 retirement. The Craig Unit 1 owners have deferred optional maintenance since 2019. Craig Unit 1 has had multiple breakdowns and required significant repairs to continue operating into 2025. On December 19, 2025, the unit suffered a valve failure that rendered Craig Unit 1 inoperable, although the unit is now available to operate following repairs made in direct response to the Order.[12]

D. DOE Order No. 202-25-14

On December 30, 2025, DOE issued Order No. 202-25-14. The Order declared that "an emergency exists within the WECC-NW assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes." DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). The Order predicated its emergency on (1) "increasing demand" and (2) "shortage from accelerated retirement of generation facilities [that] will continue in the near term and are also likely to continue in subsequent years." DOE stated, "[t]his could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety." *Id.* at 3.

DOE predicated energy reliability concerns on the 2024 Long-Term Reliability Assessment (2024 LTRA) from the North American Electric Reliability Corporation (NERC) for the WECC-NW assessment area, "which includes Colorado, Idaho,

[12] Tri-State Generation & Transmission Ass'n, Inc., *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating Next 90 Days*, TRI-STATE (Dec. 31, 2025), https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days.

Montana, Oregon, Utah, Washington, and Wyoming[.]" *Id.* at 1. DOE also pointed to the 2024 WECC Western Assessment of Resource Adequacy. The concerns included (1) greater "energy variability" due to the region's use of wind and hydropower; (2) planned retirement of baseload generation facilities fueled by coal, natural gas and nuclear; and (3) projected regional load growth. *Id.* at 2.[13]

The Order required Tri-State and the other co-owners of Craig Unit 1 to:

1. Take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, as applicable;
2. Limit operation of Craig Unit 1 to the times and within certain parameters to minimize adverse environmental impacts;
3. Provide daily notification to DOE reporting whether Craig Unit 1 has operated in compliance with the Order;
4. Comply with applicable environmental requirements including, but not limited to, monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions;
5. Update DOE on measures taken or planned to ensure operational availability of Craig Unit 1 by January 20, 2026; and
6. File with the FERC Tariff revisions or waivers to effectuate the Order with rate recovery available pursuant to 16 U.S.C. § 824a(c).

Tri-State has already taken and will continue to take steps to comply with the Order. In coordination with the other co-owners of Unit 1, it timely submitted its

[13] The Order placed these concerns in the broader context of Executive Orders 14156 and 14262. Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency; Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

update to DOE on January 20, 2026, describing the measures it has taken and plans to take to ensure operational availability of Craig Unit 1. Tri-State has submitted and continues to submit daily notification to DOE pursuant to the Order.

ARGUMENT

Petitioners seek rehearing and clarification on two fronts. *First*, the Order, as drafted, effectuates a taking of Petitioners' property under the Fifth Amendment to the United States Constitution without an adequate process to obtain constitutionally required compensation. *Second*, the Order does not meet Section 202(c)'s requirement for a reasoned finding that compels operation of Craig Unit 1 as the "best" solution to the identified emergency.

I. THE ORDER CONSTITUTES AN UNCOMPENSATED TAKING OF PETITIONERS' PROPERTY INTERESTS

Petitioners chose to close Craig Unit 1 largely because of the uneconomic nature of the facility, and Petitioners have taken numerous steps over the years to prepare for its closure. By mandating that Tri-State continue operating the facility on a sustained basis for months beyond its planned closure date, and thus directing its operations in a manner entirely inconsistent with Petitioners' own planned retirement of the facility, the Order effects an uncompensated taking of Petitioners' property in violation of the Fifth Amendment of the United States Constitution. By compelling continued operational availability of Craig Unit 1, DOE took effective control over the physical infrastructure of the facility and mandated a variety of changes to Petitioners' infrastructure and business operations, constituting both a *per se* physical and regulatory taking.

A taking is not prohibited so long as it provides just compensation, but this taking comes with no assured government compensation. FERC cost recovery shifts costs onto ratepayers; it does not assure compensation *from the government*. And, due in part to the broad scope of the declared energy emergency, FERC cost recovery related to the Order will be complex procedurally and substantively and could leave material costs unrecovered from the Order's putative beneficiaries. The Order gives Petitioners no constitutionally adequate avenue for just compensation.

A. The Order Constitutes a Physical Taking

The Fifth Amendment provides, "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. "When the government physically acquires private property for a public use, the Takings Clause imposes a clear and categorical obligation to provide the owner with just compensation." *Cedar Point Nursery v. Hassid*, 594 U.S. 139, 147 (2021) (citation omitted).

Physical takings can take a variety of forms, including intermittent or limited-value intrusions. *Id.* at 149–55; *see also Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419 (1982). Moreover, "[i]f government action would qualify as a taking when permanently continued, temporary actions of the same character may also qualify as a taking." *Ark. Game & Fish Comm'n v. United States*, 568 U.S. 23, 26 (2012). This is true even when the government has not seized title to a property but rather directed it to operate in a particular way. Temporary seizures of property to operate are takings in "as complete a sense as if the Government held full title and ownership." *See Pewee Coal Co.*, 341 U.S. at 116 (quoting *United States v. United Mine Workers of Am.*, 330 U.S. 258, 285–86 (1947)).

The Order operates as a physical taking in two interrelated ways. *First*, by directing Petitioners to maintain and operate Craig Unit 1, on a prolonged basis,[14] and in clear departure from Petitioners' own planned retirement of the facility, the Order falls within a near-century-old tradition of classifying mandatory operations—even under wartime and emergency authorities—as takings that must be compensated. *Second*, even if not characterized as a government seizure of operations, the Order constitutes a physical taking by compelling Petitioners to make material physical changes to the plant, including repairing out-of-service equipment, requiring staff onsite, and physically diverting coal allocated for Craig Units 2 and/or 3 to fuel Craig Unit 1 as the facility's operations deplete limited fuel reserves that were allocated to other units that remain operational and are needed for reliability—the depletion of these stockpiled reserves will require Petitioners to obtain replacement coal at uncertain future prices, creating an additional uncompensated cost. And because of transmission constraints, Craig Unit 1's operations could further impede Tri-State's use of the nearby Axial Basin generating facility by constraining Tri-State's ability to inject power from that facility onto the grid.

[14] Petitioners note that other similar Section 202(c) orders, issued to other utilities and on similar grounds, have been repeatedly renewed. *See, e.g.*, DOE Order No. 202-25-3 (May 23, 2025), *renewed for 90 days by* DOE Order No. 202-25-7 (Aug. 20, 2025), *renewed for 90 days by* DOE Order No. 202-25-9 (Nov. 18, 2025). Petitioners are reasonably concerned that DOE Order No. 202-25-14 could be similarly repeatedly renewed.

1. The Order's Direction of Prolonged Operations at Craig Unit 1 Contrary to Petitioners' Plan to Retire the Facility Constitutes a Physical Taking

Section 202(c) was enacted to address energy shortages that occurred during the First World War,[15] making it particularly suitable for analysis under post-war interpretations of the Takings Clause. These cases show that, even in the context of an emergency, where the government takes control of part or all of a business's facilities to use and operate for the government's purposes, a compensable taking occurs, *see, e.g.*, *United States v. Gen. Motors Corp.*, 323 U.S. 373 (1945) (holding that a government seizure of part of a leased warehouse space for military purposes was a compensable taking). Similarly, where the government requires a private business to operate in the public interest, this too constitutes a *per se* physical taking. *Pewee Coal Co.*, 341 U.S. at 116 (taking occurred when government responded to work stoppages and strikes at coal mines by directly operating them or arranging for their continued operation). Finally, these cases illustrate that a taking is particularly likely to occur where the imposition of government control extends over a lengthy period of time. *See Gen. Motors Corp.*, 323 U.S. at 375 (warehouse seized for more than a year); *Pewee Coal Co.*, 341 U.S. at 115 (government-directed operation of coal mine continued for more than 160 days).

In that light, the Order constitutes a taking of Petitioners' property. The Order requires Petitioners to, in relevant part: (1) take all measures necessary to ensure that Craig Unit 1 is available to operate; and (2) limit operation of Craig Unit 1 to

[15] Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 789–846, 800–02 (2024) (hereinafter "Rolsma (2024)").

certain times and parameters to minimize adverse environmental impacts. Even the narrowest version of the measures necessary to ensure that Craig Unit 1 is available to operate include extensive repairs to Craig Unit 1's physical facility and the ongoing employment of some share of approximately 130 staff to maintain the Craig facility, operate equipment, and remain ready to operate. The Order requires Petitioners to take these significant steps, unnecessary but-for the Order, for a prolonged period of time. This closely resembles the sustained mandate to operate that the *Pewee Coal* Court held was a taking.[16]

Indeed, the federal government recently recognized that where the government appropriates the right to control operation of a facility and deprives owners of their freedom to dispose of their property, a taking has occurred. *See* EPA-R08-OAR-2024-0607-0067, Regional Haze Round 2 at 19–21 (Jan 9, 2026), https://www.regulations.gov/document/EPA-R08-OAR-2024-0607-0067 (describing how the "unconsented closure" of a coal-fired power station constituted a *per se* taking of the facility owner's property) (citing *Cedar Point Nursery v. Hassid*, 594 U.S. 139 (2021) and *Horne*, 576 U.S. 351).

By requiring Petitioners to involuntarily keep Craig Unit 1 available for operations according to the government's instructions and mandating an

[16] The *Pewee Coal* Court did not enjoin the government's actions—the wartime emergency justified the government's effort to keep coal mines operational. The fact of a justified emergency, however, did nothing to abate the Takings Clause requirement that the government compensate the plaintiff. *See Pewee Coal Co.*, 341 U.S. at 118 (holding that government is "entitled to the benefits and subject to the liabilities" of operating a facility it takes over).

unconsented re-opening of a non-operational facility—for not hours or days but months—DOE engages in a taking.

2. The Order Mandates Physical Changes to Petitioners' Property That Constitute a Physical Taking

The physical changes to Petitioners' property mandated by the Order also constitute a *per se* physical taking of Petitioners' property rights in Craig Unit 1 and other related property, such as fuel. *First*, mandating that Petitioners make Craig Unit 1 ready for operations compels Petitioners to make material physical changes to Craig Unit 1, including repairing out-of-service equipment that would otherwise remain unused. *Second*, operations require fuel, which compels Petitioners to deplete the Craig facility's limited fuel reserves intended for Craig Units 2 and/or 3 as operations at Unit 1 continue; these reserves were acquired and measured for the anticipated operation of two specific coal units and based on the assumption that Craig Unit 1 would retire at the end of 2025. Because the Order forces Petitioners to surrender and exhaust coal inventory for the government's chosen public purpose—coal that Petitioners acquired, allocated, and reserved for other units—it effects a *per se* physical taking of that property. And *third*, transmission capacity limitations for Petitioners' facilities at and near Craig Unit 1—the Craig units and Axial Basin—mean that requiring Craig Unit 1 to remain interconnected and possibly operating could constrain the ability of these resources to fully access the grid.

a. Physical Changes to Craig Unit 1

Bringing Craig Unit 1 back into service has already required modifications to the physical infrastructure on the site, beginning with repairs to Craig Unit 1's failed

Main Steam Stop Valves #1 and #2, and including additional maintenance to the unit's baghouse that had previously been deferred based on the unit's planned December 31, 2025 retirement. Petitioners must also perform emissions testing and other evaluations to ensure that Craig Unit 1 complies with applicable environmental requirements to the "maximum extent feasible while operating consistent with the emergency conditions." Order No. 202-25-14 at 4. Ongoing operations at the site will also require continual maintenance and staffing readiness, with the potential for further equipment failures that require repair and staffing (including overtime). And long before Craig Unit 1 was scheduled to retire, Petitioners both engaged in careful resource planning resulting in generation portfolios for the future that meet all member/customer needs, as well as planning reserve margins necessary to ensure reliable capacity in the event of extreme weather events and other emergencies, all based on the assumption that Craig Unit 1 would retire from service on December 31, 2025.

Compelling a property owner to make improvements to their property constitutes a physical taking when the mandated improvement benefits others—particularly the public at large—but do not benefit the property owner. "Put in general terms, government may not force a landowner to make an improvement that, while valuable to others, is useless to him" without it constituting a compensable taking. *Furey v. City of Sacramento*, 780 F.2d 1448, 1454 (9th Cir. 1986) (citing *Norwood v. Baker*, 172 U.S. 269 (1898) and *Myles Salt Co. v. Bd. of Comm'rs*, 239 U.S. 478 (1916)), *abrogated on other grounds, Cumbre Inc. v. State Compensation*

Ins. Fund, 403 F. App'x 272 (9th Cir. 2010). The Order requires Petitioners to make significant repairs to a facility they had planned to imminently retire for good. This is the kind of taking described in *Furey*.

b. The Craig Facility's Fuel Reserve

All three Craig Units were designed to run on coal obtained from the now-shuttered Colowyo Mine and the soon-to-be-shuttered Trapper Mine.[17] Before closing the Colowyo Mine, Tri-State stockpiled sufficient reserves to operate its share of the Craig Units until their respective retirements. The only practical source of fuel for Craig Unit 1 to maintain readiness after its planned retirement, and to make use of in the event of a dispatch, are Craig Units 2 and/or 3's previously acquired and allocated reserves.[18]

This too constitutes a taking. *See Horne*, 576 U.S. at 357–65 (USDA requirement that a percentage of a grower's crop be set aside for public use constituted a *per se* physical taking). Just as the government in *Horne* effected a *per se* taking by requiring raisin growers to surrender a specific, identifiable portion of their crop for public use, by mandating that Petitioners consume coal inventory purchased and reserved for Craig Units 2 and/or 3, DOE appropriates that property for a public reliability objective. Under *Horne*'s reasoning, forced depletion of a

[17] Tri-State believes that co-owners supply their share of Craig Units 1 and 2 through Trapper or other mines.

[18] The diversion of this coal will necessitate future purchases of replacement fuel at uncertain cost, thereby imposing an additional, uncompensated expenditure that independently constitutes a taking. Use of an alternative source of supply not only results in additional costs, but also requires Tri-State to negotiate new contracts and alter operations at the Craig facility to account for variances between the physical qualities of different coal supplies.

utility's fuel reserves—no less than forced surrender of raisins—constitutes a physical taking of personal property requiring just compensation.

c. Axial Basin

The 145 MW Axial Basin generating facility is in the same general location as the Craig Generating Station and relies on much of the same transmission infrastructure. There is insufficient transmission capacity to move all electricity generated by the three Craig units and Axial Basin to the broader power grid. The Order thus constitutes appropriation of Tri-State's transmission infrastructure, a clear physical intrusion. This transmission limitation could lead to further physical intrusion by potentially forcing the curtailment of one or more of the other generation facilities to ensure that there was sufficient transmission capacity available for Unit 1 to comply with the Order.

B. DOE's Order Constitutes a Regulatory Taking

In addition to being a *per se* physical taking, the Order constitutes a regulatory taking. Regulatory takings occur where the government "imposes regulations that restrict an owner's ability to use his own property" but goes too far. *Cedar Point Nursery*, 594 U.S. at 148. The property rights implicated by the Takings Clause can include contract rights, *see Lynch v. United States*, 292 U.S. 571, 579 (1934), and government-created entitlements with economic value, *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986 (1984) (trade secrets constituted property for takings purposes). When evaluating whether a regulatory burden constitutes a taking, courts look to the test established in *Penn Central Transportation Co. v. New York City*, 438 U.S. 104, 124 (1982), which evaluates regulatory takings based on: (1) the regulation's economic

impact; (2) its interference with reasonable investment-backed expectations; and (3) the character of the government action.

The Order constitutes a regulatory taking under this analysis. The Order levies substantial economic impacts on Petitioners through both direct maintenance costs and the disruption to Petitioners' planning with associated downstream costs. The Order also disrupts Petitioners' reasonable investment-backed expectations rooted in years-long resource and economic planning, and interferes with Petitioners' operations and their contractual and regulatory rights.

1. Economic Impact

In requiring Petitioners to "take all measures necessary to ensure that Craig Unit 1 is available to operate," the Order places a heavy economic burden on Petitioners. As discussed above, Petitioners will necessarily incur a variety of operations and maintenance costs to ensure that Craig Unit 1 is ready and able to operate on request, with no economic benefit available from retaining the to-be-retired facility because it is uneconomic to operate.

Moreover, because of limited capacity over common transmission facilities, dispatching Craig Unit 1, while the other Craig Units are operating, can impede Tri-State's ability to dispatch its nearby Axial Basin generating facility. This in turn, prevents Petitioners from gaining the benefit of a margin on more economic resources, including renewable energy credits (which themselves have tangible value). *See Ruckelshaus*, 467 U.S. at 1011 (trade secrets are property); *Cienega Gardens v. United States*, 331 F.3d 1319, 1329 (Fed. Cir. 2003) (option rights to prepay subsidized mortgage and exit affordable-housing program are property); *Casitas*

Mun. Water Dist. v. United States, 543 F.3d 1276, 1288–96 (Fed. Cir. 2008) (water capacity rights are property). Forced operations would prevent Petitioners from most efficiently and affordably managing the transmission and generation system.

2. Investment-Backed Expectations

"The regulatory regime in place at the time the claimant acquires the property at issue helps to shape the reasonableness of [investment-backed] expectations." *Palazzolo v. Rhode Island*, 533 U.S. 606, 633 (2001) (O'Connor, J., concurring). Where a change in regulation dramatically disrupts the economic basis for a property owner's choices, it constitutes unreasonable interference with reasonable investment-backed expectations. *See Petworth Holdings, LLC v. Bowser*, 3d 347, 356–58 (D.C. Cir. 2018). An explicit government guarantee forms the basis of a reasonable investment-backed expectation. *See Ruckelshaus*, 467 U.S. at 1011.

The Order disrupts Petitioners' reasonable investment-backed expectations on several fronts. DOE's use of Section 202(c) authority to address long-term predicted shortages or grid reliability problems is a substantial and novel change to prior uses of Section 202(c) emergency authority.[19] The Order fundamentally alters DOE's longstanding approach in a novel, untested way that could not be predicted from DOE's actions until recently, a decade after Craig Unit 1's 2025 retirement was announced. Petitioners could not have fairly anticipated DOE's novel approach to Section 202(c) when it engaged in business planning and made investment decisions; thus, the Order upsets Petitioners' reasonable expectations.

[19] *Rolsma* (2024) at 802–09, 839–46 (discussing paucity of involuntary Section 202(c) orders since WW2).

Moreover, diverting coal from Craig Unit 1 to comply with the Order depletes Craig Unit 2 and 3's fuel reserves and hinders Petitioners' right and ability to freely use those facilities consistent with their investment-backed expectations. The Order also upsets Petitioners' delicate contractual relationships. Even if Section 202(c) provides protection from enforcement action by Colorado under "environmental" laws,[20] disruption to these longstanding relationships disturbs Petitioners' ability to manage risk, engage in long-term planning, and maintain their reputations as reliable counterparties. Notwithstanding possible regulatory action, Petitioners have made commitments to stakeholders and planned their businesses around complying with existing environmental laws, which form part of their investment-backed expectations.

Finally, the electrical generation and transmission industry operates on a long time horizon. Craig Unit 1's closure was announced a decade ago, and numerous steps, such as deferring maintenance, reducing staffing, and redirecting capital expenditures, have been undertaken since. As is best practice, Petitioners engaged in extensive long-term planning with both government and private-sector partners, and Petitioners' plan to close Craig Unit 1 is part of a long-term plan to retire Unit 1 for economic reasons. Disruption of these long-term plans through a shorter-term Order upsets Petitioners' reasonable investment-backed expectations.

[20] Section 202(c)(3) does not define "environmental law" in this context and the scope of that term is untested.

3. Character of the Taking

The character of a governmental action is defined by "the purpose and importance of the public interest underlying [the] regulatory imposition, by obligating the court to inquire into the degree of harm created by the claimant's prohibited activity, its social value and location, and the ease with which any harm stemming from it could be prevented." *Maritrans, Inc. v. United States*, 342 F.3d 1344, 1356 (Fed. Cir. 2003) (internal quotation and citation omitted). "A 'taking' may more readily be found when the interference with property can be characterized as a physical invasion by government . . . than when interference arises from some public program adjusting the benefits and burdens of economic life to promote the common good." *Penn Central*, 438 U.S. at 124 (citations omitted).

The character of the Order's action further strengthens the case for a regulatory taking. As discussed in Section (I)(A), the Order effectively commandeers Craig Unit 1, its fuel, the potential dispatch of the nearby Axial Basin facility, and related infrastructure owned by Petitioners. The Order does not merely adjust the benefits and burdens of economic life, but rather directs operational control for a public reliability aim that could—and should—be solved through other means, and by other electrical utilities.

C. Just Compensation

The Takings Clause provides that "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. Whether compensation is "just" is measured by relation "both to an owner whose property is taken and to the public that must pay the bill[.]" *United States v. Commodities Trading Corp.*, 339

U.S. 121, 123 (1950). "The owner's loss is measured by the extent to which governmental action has deprived him of an interest in property." *Wheeler v. City of Pleasant Grove*, 833 F.2d 267, 270 (11th Cir. 1987).

There is no established process by which Petitioners will obtain government compensation for losses relating to the Order. Section 202(c) and its implementing regulations, namely 10 C.F.R. 205.376, suggest recovery through FERC rate-making processes, but nowhere does the Order guarantee Petitioners' complete recovery.[21] As one example of the complexity of this undertaking, WAPA and the Bonneville Power Administration, as Federal Power Marketing Administrations located within WECC-NW, are exempt from most FERC jurisdiction.[22] It is not immediately clear how the FERC rate-making process could be used to secure cost recovery from utilities serving areas located within the scope of the emergency but over which FERC lacks jurisdiction.

Moreover, even if Petitioners can and do recover some costs through this process, it is still not *just compensation* within the meaning of the Takings Clause. The duty to pay compensation for a taking runs to the government—"a takings claim requires just compensation from the government, not from a private third party." *See*

[21] Additionally, the terms of the Order could have substantive impact on Tri-State's ability to make energy sales at market-based rates through authority granted to it by FERC. *See, e.g.*, *Tri-State Generation and Transmission Ass'n,* 170 FERC ¶ 61,220, at PP 1, 22 and ordering para. (A) (2020) (generally providing Tri-State with authorization to transact at market-based rates). The circumstances are analogous for Platte River. Platte River also makes energy sales at market rates, but, as a government utility exempt under FPA Section 201(f), Platte River does not need market-based rate authority from FERC.

[22] Stating that "[n]o provision in this subchapter shall apply to, or be deemed to include, the United States." 16 U.S.C. § 824(f) (2024).

Deutsche Bank Nat'l Trust Co. v. SFR Invests. Pool 1, LLC, Case No. 2:14-cv-001131-APG-VCF, 2016 WL 1248704, at *5 (D. Nev. Mar. 28, 2016); *see also Baker v. City of McKinney*, 608 F. Supp. 3d 457, 465–67 (E.D. Tex. 2022) (plaintiff was entitled to full compensation for a taking by police even though she obtained additional money from donations). This is particularly true where, as here, at least some of Petitioners' relief will come from Tri-State's members and Platte River's ratepayers, even if FERC orders some level of cost recovery. DOE cannot simply transfer the constitutional obligation to provide just compensation onto private parties—including, here, rural communities and the residents of four small Colorado municipalities—through regulatory mandates without satisfying its own Takings Clause obligations.

II. THE ORDER DISRUPTS PETITIONERS' RELIABILITY PLAN AND FAILS TO ACCOUNT FOR VIABLE ALTERNATIVES

Separate from whether DOE must compensate Petitioners for the impact of the Order on their property and operations, the Order suffers from statutory and constitutional frailties. While Petitioners share DOE's goal of ensuring that the Northwestern United States has reliable and affordable electricity, the Order misses the mark.

First, the Order violates Petitioners' constitutional due process rights to pre-deprivation notice and a hearing. While emergencies sometimes allow the government to provide only post-deprivation process, the government must do more than reference the word "emergency"—rather, it must show that the *kind* of emergency that requires such fast-moving action has occurred. The Order's asserted

emergency is no such emergency. And the Order disrupts a considered resource planning effort.

Second, the Order does not meet the requirements of Section 202(c). It does not consider reasonable alternatives as required by Section 202(c), including Petitioners' carefully calibrated reliability planning, using both thermal and renewable resources based on findings including from objective, industry-leading forecasting methods. *Third*, the Order is inconsistent with the FPA's objectives. The Order is, therefore, contrary to law and arbitrary and capricious.[23]

A more deliberative process would, on the whole, work better to address DOE's concerns about the reliability of the electrical grid in the northwestern United States, and, in particular, the Mountain West. Petitioners stand ready to work with DOE to make their service area as reliable as possible and best serve their members and customers, doing so in a manner that is economically efficient.

A. The Order Violates Petitioners' Constitutional Due Process Rights and Disrupts Carefully Considered Reliability Planning

The Fifth Amendment's Due Process Clause guarantees that no person shall be "deprived of life, liberty or property" by the federal government "without due

[23] As DOE is aware, Petitioners have already taken and will continue to take steps to comply with the Order. This includes incurring compensable costs and expenses. Although Petitioners take the position that the Order does not comply with the requirements of Section 202(c), Petitioners are nonetheless entitled to cost recovery under Section 202(c) and as a compensable taking even if the Order is determined to be unlawful. Petitioners note that Section 202(c) is an emergency provision, and, for that reason, recovery pursuant to its terms should not turn on an ultimate determination of the lawfulness of the Order. Further, the Order provided notice to all potential ratepayers that rights to recovery would accrue to Petitioners (and the other co-owners) beginning on December 30, 2025. To bar Petitioners from recovering these already-incurred costs would be inconsistent with Section 202(c)'s purpose to respond to emergency conditions. Petitioners' position is based on currently available facts and information. Petitioners reserve all rights.

process of law." U.S. Const. amend. V. At its core, due process requires notice and an opportunity to be heard before the government takes action affecting protected interests. *Memphis Light, Gas & Water Division v. Craft*, 436 U.S. 1, 19 (1978). This principle applies across regulatory regimes where hearings are generally required before agencies impose obligations or alter rights. Under the FPA, most Commission (*i.e.*, FERC or DOE) actions—such as rate changes or interconnection orders—cannot take effect without a prior hearing. *See generally* 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o, & 824p.

Section 202(c) orders are unusual in that they may be issued without any prior hearing, reflecting their purpose as an emergency tool meant to address fast-moving and unexpected situations. *Indus. Park Dev. Co. v. EPA*, 604 F. Supp. 1136, 1142 (E.D. Pa. 1985) ("[A]dministrative deprivation of [a] property interest violates the Constitution's due process guarantees except in very narrowly circumscribed emergency situations."). However, "[t]here is a relation between the kind of emergency and nature of the solution." *Pa. Gas & Water Co.*, 427 F.2d at 577. Where, as here, the declared emergency does not involve immediate and concrete concerns (potentially in 2029 if new generation is not built as planned), a hearing is certainly feasible, and, absent a hearing, Petitioners are deprived of their right to due process. *See Indus. Park Dev. Co.*, 604 F. Supp. at 1145 (holding that "[u]nilateral administrative action . . . should be saved for cases of extreme emergency"); *Miller*,

945 F.2d at 353 (emergency insufficient to avoid need for pre-deprivation hearing, but concluding that sufficient hearing had occurred).

The Order's emergency does not rest on an urgent and immediate need for additional generation to address a specific incident or event, such as unusually extreme weather or another plant's sudden unplanned outage. Rather, the emergency articulated by the Order is based on broader concerns about the sufficiency of generation capacity and reliability in the WECC Northwest assessment area over time and in the future. Because the Order does not demonstrate an immediate crisis, it cannot justify dispensing with the pre-deprivation hearing requirement. Formal notice to the co-owners, moreover, was lacking. The Order's imprecision on boundaries of the region at issue,[24] not only highlights the lack of immediate crisis, but also fails to give Petitioners proper notice of the precise contours of the emergency. Petitioners were, therefore, deprived of their constitutional right to notice and a hearing before the Order came into effect.

The effect of this deprivation is significant. Petitioners have carefully planned the retirement of the Craig facility—including Craig Units 2 and 3's reliance on

[24] The Order relies on NERC's 2024 LTRA, which discusses conditions throughout the sweeping and populous WECC Northwest assessment area—an area that includes "Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota[.]" *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, at 127 (corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf. However, NERC's more recent and more targeted 2025–2026 Winter Reliability Assessment from November 2025 shows that the new WECC-Rocky Mountain region—redrawn to better reflect local conditions than the vast and heterogeneous old WECC-Northwest region—has more than enough power to meet immediate winter needs. *See* N. Am. Elec. Reliability Corp., 2025 Winter Reliability Assessment (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf. Craig Unit 1 and most of Petitioners' service territory is located in the WECC-Rocky Mountain region.

stockpiled coal. Petitioners have also planned and invested to bring new generation online, such as the Axial Basin facility, to ensure reliability even as Craig Unit 1 is carefully retired. If the Order proceeds and Unit 1 runs, it deprives the other units of fuel. This undermines Petitioners' planning, imposes "reliability" costs on Tri-State's members and Platte River's ratepayers a second time, and disrupts the operation and economics of the other coal resources still operating. A more deliberative process with the required pre-deprivation hearing would have allowed Petitioners to work with DOE to address concerns about reliability and shape a more workable plan.

B. The Order Failed to Consider Reasonable Alternatives

DOE could have taken other steps to more effectively meet the energy emergency identified in the Order. Section 202(c) requires the Secretary to exercise "judgment" and select only those measures that "will *best* meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1) (emphasis added). Implicit in this mandate is the recognition that alternatives be considered and ruled out. DOE should have conducted and disclosed an analysis showing why the path selected is the "best" course forward, particularly in light of the potential 2029 time-horizon of the asserted emergency. This is consistent with the emergency nature of the powers contained in Section 202(c), which should not be exercised where "alternatives offered a more confined solution" to the emergency at issue. *Pa. Gas & Water Co.* 427 F.2d at 577 (considering analogous powers under the Natural Gas Act); *see also Farmers Union Cent. Exchange, Inc. v. FERC*, 734 F.2d 1486, 1511 (D.C. Cir. 1984) ("It is well established that an agency has a duty to consider reasonable alternatives to its chosen policy, and to give a reasoned explanation for its rejection of such

alternatives.") (citation and footnote omitted). The Order reflects no consideration of alternatives, let alone a case for mandating Craig Unit 1 remain active over other options, and is thus contrary to law and arbitrary and capricious.

Compelling Craig Unit 1 to remain available to operate after its planned retirement date must be the "best" measure to address this long-term reliability concern across the region described in the Order. "[R]easonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions." *Michigan v. EPA*, 576 U.S. 743, 753 (2015). This weighing process requires engagement with the factual record, as reflected in DOE regulations, which require applicants to provide extensive information related to operations and alternative courses of action.[25] These requirements reflect the understanding that Section 202(c) should only be used where unit-specific alternatives have been considered, applied, and deemed inadequate based on the facts on the ground. The record in this proceeding reflects that neither these facts nor any reasonable alternatives were considered in connection with the Order.

DOE's need to consider alternatives, based on a clear factual record, is particularly important given Craig Unit 1's status. Craig Unit 1 is an older, uneconomic unit. Due to its long-planned retirement, Craig Unit 1 has experienced years of prudently deferred maintenance, and therefore faces particularly high costs to restore and maintain operations compared to possible alternatives.

[25] *See* 10 C.F.R. § 205.373. The specified information includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "[a] listing of proposed sources and amounts of power necessary from each source to alleviate the emergency and a listing of any other 'entities' that may be directly affected by the requested order." 10 C.F.R. § 205.373(g)–(i).

Further, the Order fails to consider how mandating Craig Unit 1's continued operation interferes with Petitioners' ability to invest in other generation capacity and therefore undermines the very ends that it purports to advance. For instance, the Axial Basin generating facility relies on the same transmission infrastructure as the Craig units. That infrastructure is already congested; if all three Craig units are operating, Craig Unit 1's continued operation could interfere with the ability of new alternatives like Axial Basin to provide economic power to the grid.

A lawful exercise of the emergency powers contained in Section 202(c) required consideration of reasonable regulatory alternatives. For example, the Order does not explain why DOE or FERC could not proceed through the rulemaking process pursuant to section 403 of the Department of Energy Organization Act, 42 U.S.C. § 7173, to devise a plan to ensure reliability through a more fulsome, consultative process. Proceeding with a notice of proposed rulemaking for consideration and final action would have minimal short-term risks and is appropriate to the timeline of the described emergency, which, by DOE's supporting evidence, is predicted to occur no earlier than "in Summer 2029 onward" (because "the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed").[26] Similarly, DOE could have evaluated whether it had authority to take proactive action to insure that "new resources" in the region are not "significantly delayed."

[26] N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, at 128 (corrected July, 11 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

In the absence of such consideration, and the disclosure of the relevant rationale, Petitioners and the public "cannot weigh the merits of an agency decision nor compare it to other alternative actions[.]" *Rocky Mountain Wild v. Bernhardt*, 506 F. Supp. 3d 1169, 1187 (D. Utah 2020). The Order does not discuss why Craig Unit 1's continued operation was selected as the "best" solution to the described conditions, or if alternatives were considered, what those alternatives were, and why any considered alternatives were discarded. Thus, it was contrary to law and an arbitrary and capricious exercise of agency authority.

C. The Order is Inconsistent with the FPA's Statutory Objectives

Courts reject agency action as arbitrary and capricious if it is "inconsistent with the statutory mandate" or "frustrate[s] the policy that Congress sought to implement." *FEC v. Democratic Senatorial Campaign Comm.*, 454 U.S. 27, 32 (1981). The FPA was passed to advance a variety of policy goals, including protecting consumers from "excessive rates and charges," *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 952 (D.C. Cir. 2016) (citation omitted)); "maintaining competition to the maximum extent possible[,]" *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973); and encouraging the "orderly development of plentiful supplies of electricity . . . at reasonable prices." *NAACP v. FPC*, 425 U.S. 662, 670 (1976).[27]

[27] "Recognizing the careful balance that the FPA strikes between federal and state regulation" FERC recently found that "states retain exclusive authority over . . . the generation mix." *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61217, at P165 (Dec. 18, 2025). Long-term economic and planning decisions regarding Tri-State's resource mix had been approved by the State of Colorado through the 2020 and 2023 Energy Resource Plans. This jurisdictional division of responsibility and federal respect for state policymaking is also a policy of the FPA. *See Sierra Club v. FERC*, 145 F.4th 74, 81 (D.C. Cir. 2024) (respecting the role of state regulators); *NextEra Energy Resources, LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024) ("[FERC] may regulate the transmission, but not the generation, of electricity[.]").

The Order, by compelling an uneconomic unit to remain operational on the eve of its retirement, upends Petitioners' ability to plan their systems in an orderly fashion and to act with confidence in a competitive marketplace. Because the Order is at odds with the statutory objectives of the FPA, it is arbitrary and capricious.

CONCLUSION

Tri-State is a not-for-profit, member-owned cooperative and Platte River is a not-for-profit municipally owned joint action agency. Both utilities aim to work with government at all levels to best serve the communities to which they provide reliable and affordable energy. In that light, Tri-State has taken the steps necessary to plan for a reliable system that would have a planning reserve margin of at least 22% even with the retirement of Craig Unit 1, for which its Utility Members have paid. Platte River has likewise proactively developed resources that more than replace Craig Unit 1's energy and capacity to reliably serve its owner communities and meet the planning reserve margins SPP requires for its expanded western footprint (19% for summer; 40% for winter), and for which its owner communities have already paid.

The Order effects an uncompensated taking of Petitioners' property, denies them due process, and fails to meet Section 202(c)'s statutory requirement that DOE's chosen policy rationally "best address[es]" the stated emergency. Requiring Petitioners—not all of whom are located in the WECC Northwest region described by the Order—to suffer additional costs *and* uncertainty because of potential conditions created by utilities outside Petitioners' service area, is fundamentally unfair and harms affordability. Petitioners urge DOE to reconsider the Order.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties below. Dated at Washington, D.C., this 29th day of January 2026.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-176
Xcel Motion to Intervene in Petition for Rehearing

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

State of Colorado,	)	
Petitioner,	)	
v.	)	**Case Nos. 26-1059** **26-1060**
United States Department of Energy and Chris Wright, Administrator, United States Department of Energy,[1]	)	**(Consolidated)**
Respondents.	)	

MOTION FOR LEAVE TO INTERVENE OF PUBLIC SERVICE COMPANY OF COLORADO

Public Service Company of Colorado ("Public Service") respectfully moves for leave to intervene in the consolidated petitions for review filed by the State of Colorado and by the Sierra Club, Vote Solar, and the Environmental Defense Fund (collectively, "Petitioners") in the above-captioned proceedings. Public Service is the object of the agency actions that the Petitioners challenge and seeks leave to intervene to protect its

[1] The case caption refers to the Secretary of the Department of Energy as "Administrator."

interests. At present, Public Service does not support or oppose either side. Accordingly, Public Service respectfully requests that it be permitted to file a brief with or after Respondent Department of Energy ("Department").

In support of this motion, Public Service states the following:

Public Service is a wholly owned subsidiary of Xcel Energy Inc. and is a combination gas and electric utility serving various geographic areas in Colorado. Public Service provides (i) natural gas local distribution service to approximately 1.4 million residential, commercial, and industrial customers in northern, central, southern, and western parts of Colorado; (ii) cost-based electric service to approximately 1.5 million retail customers in Colorado, subject to the jurisdiction of the Colorado Public Utilities Commission; and (iii) cost-based wholesale requirements service to five customers within Colorado, subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Public Service is a co-owner of Craig Unit 1, a 446.4 MW coal-fired generator in Craig, Colorado, which is the subject of the orders challenge by Petitioners here.

On March 18, 2026, the State of Colorado (Case No. 26-1059) and the Sierra Club, Vote Solar, and the Environmental Defense Fund (Case

No. 26-1060) filed petitions for review of the following orders issued by the Department:

1. Federal Power Act Section 202(c) Emergency Order for Craig Unit 1, DOE Order No. 202-25-14 (December 30, 2025); and

2. *Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, Xcel Energy Inc., Western Area Power Administration – Rocky Mountain Region, and Southwest Power Pool Regarding Craig Station*, DOE Order No. 202-25-14A (March 2, 2026).

The Department orders concern an electric generation facility partially owned by Public Service. On December 30, 2025, the Department issued Order No. 202-25-14 ("Craig 1 Order"), pursuant to Section 202(c) of the Federal Power Act, to the co-owners of Craig Unit 1–Tri-State Generation and Transmission Association ("Tri-State"), Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy.[2] (*Fed. Power Act § 202(c) Emergency Order for Craig Unit 1*, DOE Order No. 202-25-14 (Dec. 30, 2025)). The Craig 1 Order directs "Tri-State and the co-owners" to "take all measures necessary to ensure that Craig Unit 1 is available," as well as to provide information regarding facility operations and environmental and operational impacts

[2] Public Service is the Xcel Energy Inc. operating company subsidiary that is the co-owner for Craig Unit 1.

of compliance. (*Id.* at 1, Ordering ¶ A). Although the co-owners had intended to cease operations at the end of December 2025, the Craig 1 Order requires the facility to remain available until at least March 30, 2026. (*Id.* at 1, Ordering ¶ H).

"There is ordinarily little question" that the "object of the government action" has standing in a case challenging the action. *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 561–562 (1992). Here, the Craig 1 Order has caused Public Service and other co-owners to incur substantial additional operations, maintenance, and fuel costs. For these evident reasons, Public Service has a direct and substantial interest in these proceedings—at a minimum, its concrete interest in recovering costs of compliance with the Department's order ensuring that these petitions do not impair Public Service's ability to recover its costs.[3]

At this time, Public Service expects to take no position on the legality of the Department's order, including whether it should be upheld

[3] This interest demonstrates an injury-in-fact to a legally protected interest, causation, and redressability sufficient to establish Article III standing. *Cf. Fund for Animals, Inc. v. Norton*, 322 F.3d 728, 732–33 (D.C. Cir. 2003); *Institutional S'holder Servs., Inc. v. SEC*, 142 F.4th 757, 764 & n.3 (D.C. Cir. 2025) (noting that intervenors seeking the same relief as an existing party need not establish independent standing under Supreme Court precedent).

or set aside on the merits. Public Service seeks leave to intervene to protect its interests and respond to arguments that relate to Public Service's ability to assign, allocate, and recover costs. Public Service has incurred and will continue to incur substantial costs to comply with the Department's order. Public Service estimates that its share of the costs to comply with the Department's order has been approximately $100,000.[4] Neither Petitioners, the Department, nor the other co-owners can adequately represent Public Service's interests in cost assignment or allocation.

Public Service's intervention is supported by *Michigan v. Department of Energy*. *Michigan* involves another recent Department order under Section 202(c) and even involves some of the same Petitioners as are in this proceeding. (*See* Br. for Pet. in *Michigan v. Dep't of Energy*, D.C. Cir. Case No. 25-1159 (filed Dec. 19, 2025)). In *Michigan*, the affected utility did not take a position on the legality of the Department's order and had originally intended to participate only as an amicus. However, after the petitioners' opening brief raised cost recovery

[4] The estimate is subject to change because final costs are still being determined.

issues, the utility moved out-of-time to intervene to defend its interests. (*See* Mot. of Consumers Energy Co. for Leave to Intervene & for Extension of Time in *Michigan*, D.C. Cir. Case No. 25-1159 (filed Dec. 26, 2025)). Owing to the substantial stakes for that utility, the Court granted the utility's out-of-time motion and permitted it to file a brief with the respondent-intervenors. (*See id.* at 2-3, 10; Order in *Michigan*, D.C. Cir. Case No. 25-1159 (Feb. 5, 2026) (granting intervention) ("*Michigan* Intervention Order")).

Public Service is in the same basic position as the *Michigan* utility in that it intends to participate to defend its ability to recover costs, if that issue arises, and does not intend to take any position on the legality of the Department's Order. The only difference here is that, unlike the utility subject to an equivalent order in the *Michigan* case, Public Service is moving to intervene at the outset rather than assuming a wait-and-see approach that risks the need for an out-of-time motion.

The Court should grant Public Service leave to intervene in support of neither party and file its brief with or after the respondent's brief.

Respectfully submitted,

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Dated: April 9, 2026

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

State of Colorado,	)	
Petitioner,	)	
v.	)	
United States Department of Energy and Chris Wright, Secretary, United States Department of Energy,[5]	)	**Case Nos. 26-1059 26-1060** **(Consolidated)**
Respondents.	)	

CORPORATE DISCLOSURE STATEMENT OF PUBLIC SERVICE COMPANY OF COLORADO

In accordance with Rule 26.1 of the Federal Rules of Appellate Procedure and Rule 26.1 of the Rules of this Court, Public Service Company of Colorado ("Public Service") provides the following disclosure statement:

Public Service is a combination gas and electric utility incorporated in Colorado that serves various geographic areas in the State of Colorado.

[5] The case caption refers to the Secretary of the Department of Energy as "Administrator."

Public Service is a wholly owned utility subsidiary of Xcel Energy Inc. ("Xcel Energy"). There are no other parent corporations or publicly held companies that own a 10% or greater ownership interest in Public Service. Public Service's principal place of business is 1800 Larimer Street, Suite 1100, Denver, CO 80202.

Xcel Energy is a Minnesota corporation and a holding company under the Public Utility Holding Company Act of 2005. Xcel Energy's principal place of business is 414 Nicollet Mall, Minneapolis, Minnesota 55401. Xcel Energy is a publicly traded company on the NASDAQ under the symbol "XEL." The Vanguard Group, Inc. is the only entity that owns a 10% or greater ownership interest in Xcel Energy. No affiliate of Public Service, other than Xcel Energy, has issued shares to the public.[6]

[6] Certain operating company subsidiaries of Xcel Energy have issued first mortgage bonds and other debt securities that are publicly traded, including Southwestern Public Service Company; Northern States Power Company, a Minnesota corporation; Northern States Power Company, a Wisconsin corporation; and PSCo. A complete list of all debt securities of Xcel Energy and its subsidiaries is available at the Xcel Energy website (www.xcelenergy.com) under "Investors."

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CERTIFICATE OF COMPLIANCE WITH TYPE-VOLUME LIMIT

I hereby certify that this motion complies with the type-volume limitation, the typeface requirements, and type-style requirements in Rules 27(d)(2)(A), 32(a)(5), and 32(a)(6) of the Federal Rules of Appellate Procedure because this motion contains 1,069 words and was prepared in a proportionally spaced typeface using Microsoft® Word for Microsoft 365 MSO in Century Schoolbook 14-point font.

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Dated: April 9, 2026

CERTIFICATE OF SERVICE

Pursuant to Rules 15(d) and 25(d) of the Federal Rules of Appellate Procedure and Circuit Rule 25, I hereby certify that I electronically filed the foregoing with the Clerk of the Court for the United States Court of Appeals for the D.C. Circuit by using the appellate CM/ECF system. Participants in these cases will be served by email through the Court's CM/ECF system.

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Dated: April 9, 2026

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-177
March 30, 2026 Colorado Sun Article

THE COLORADO SUN

DONATE

NEWS: CLIMATE, ENERGY, ENVIRONMENT, NEWS

Life of coal burning Craig Unit 1 extended again by Trump administration

Against the wishes of its owner and many others, Department of Energy says plant is needed to generate electricity to cover emergencies, growing demand



Michael Booth

3:50 PM MDT on Mar 30, 2026



The Queen Anne dragline, with the Tri State Craig Station power plant in the background, is shown operating at the Trapper Mine in Craig, Colo., Sept. 27, 2006. (AP Photo/Denver Post, Brian Brainerd)

The Trump administration's Department of Energy on Monday extended its emergency order keeping coal-burning Craig Unit 1 open against the wishes of its

owners as well as Colorado regulators and environmental advocates.

The plant, scheduled for a Dec. 31 permanent shutdown by Tri-State Generation and Transmission **long before the first Trump emergency order**, will now stay open and available to bolster Western power supplies through at least June, the order says.

Colorado Attorney General Phil Weiser and other states are **challenging the coal plant extensions in federal court**, but have not yet won reversals. Opponents of the extensions renewed their criticism, calling coal power needlessly costly and dangerous to the health of Colorado residents.

"The Trump administration has doubled down on an order that no one seems to want except the coal industry," said Leslie Coleman, senior attorney with Earthjustice's Rocky Mountain Office. "Craig's co-owners have had to pour money into this aging and unreliable unit to keep it available, and those costs are likely to be passed on to Coloradans. It is time for the administration to stand down and allow this unit to retire as utilities and state regulators had long planned."

Tri-State Generation, a power-supplying co-op that co-owns the northwestern Colorado unit, has said it completed repairs earlier this year and the plant has been available to respond to demand orders from regional power coordinators. But the plant still hadn't been called on for actual power as of Monday, said Tri-State officials, who are reviewing the new order.

Tri-State and environmental groups have said the federal orders have not offered any information about who will pay to keep Craig 1 operating, **which could cost more than $80 million over a year**.

"The emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years," according to the order by Secretary of Energy Chris Wright. "This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety."

Colorado clean energy officials and advocates counter that Craig's power is not needed, and that the state had planned carefully for years to make sure cleaner sources came online while state rules required retirement of the last six coal plants by 2030. Colorado says it needs the coal plants to close to meet a number of clean air goals, including an 80% reduction in greenhouse gas emissions from the power sector by 2030.

Instead, Colorado's life as a coal state keeps getting extended. In addition to the Craig order, Xcel has been allowed to extend the life of the Comanche 2 unit in Pueblo while it completes repairs on the damaged Comanche 3. Colorado Spring Utilities, meanwhile, is asking the state for permission to keep burning coal at its Ray D. Nixon plant in Fountain past the previously scheduled closing in 2029, while it builds replacement power.

The Craig Station owners have also noted the double-whammy they face with the unit's coal energy: There's only so much transmission capacity in northwestern Colorado, and if they have to force coal power out onto the lines, they won't be able to use solar electricity generated by the newly added **145MW Axial Basin solar farm in Moffat County**.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-178
NERC 2025 Long-Term Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Long-Term Reliability Assessment

January 2026



Table of Contents

Preface 3
About This Assessment 4
Reading This Report 5
Executive Summary 6
Capacity and Energy Risk Assessment 6
Trends and Reliability Implications 9
Recommendations 10
Capacity and Energy Risk Assessment 12
Assessment Approach 12
Risk Categories 12
Resource and Demand Projections 23
Reducing Resource Capacity and Energy Risk 24
Demand Trends and Implications 25
Demand and Energy Projections 25
Reliability Implications 29
Resource Mix Changes 30
Planned On-Peak Capacity Additions 31
Transmission Development and Interregional Transfer Capability 37
Transmission Projects 37
Interregional Transfer Capability Study (Canadian Analysis) 38
Regional Assessments Dashboards 41
MISO 42
MRO-Manitoba Hydro 49
MRO-SaskPower 54
MRO-SPP 59
NPCC-Maritimes 63
NPCC-New England 68
NPCC-New York 74
NPCC-Ontario 80
NPCC-Québec 86
PJM 90
SERC-Central 95
SERC-East 102
SERC-Florida Peninsula 112
SERC-Southeast 120
Texas RE-ERCOT 128
WECC-Alberta 134
WECC-Basin 138
WECC-British Columbia 143
WECC-California 147
WECC-Mexico 151
WECC-Northwest 154
WECC-Rocky Mountain 159
WECC-Southwest 163
Demand Assumptions and Resource Categories 167
Methods and Assumptions 171
Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area 175
Recommendations and ERO Actions Summary 177

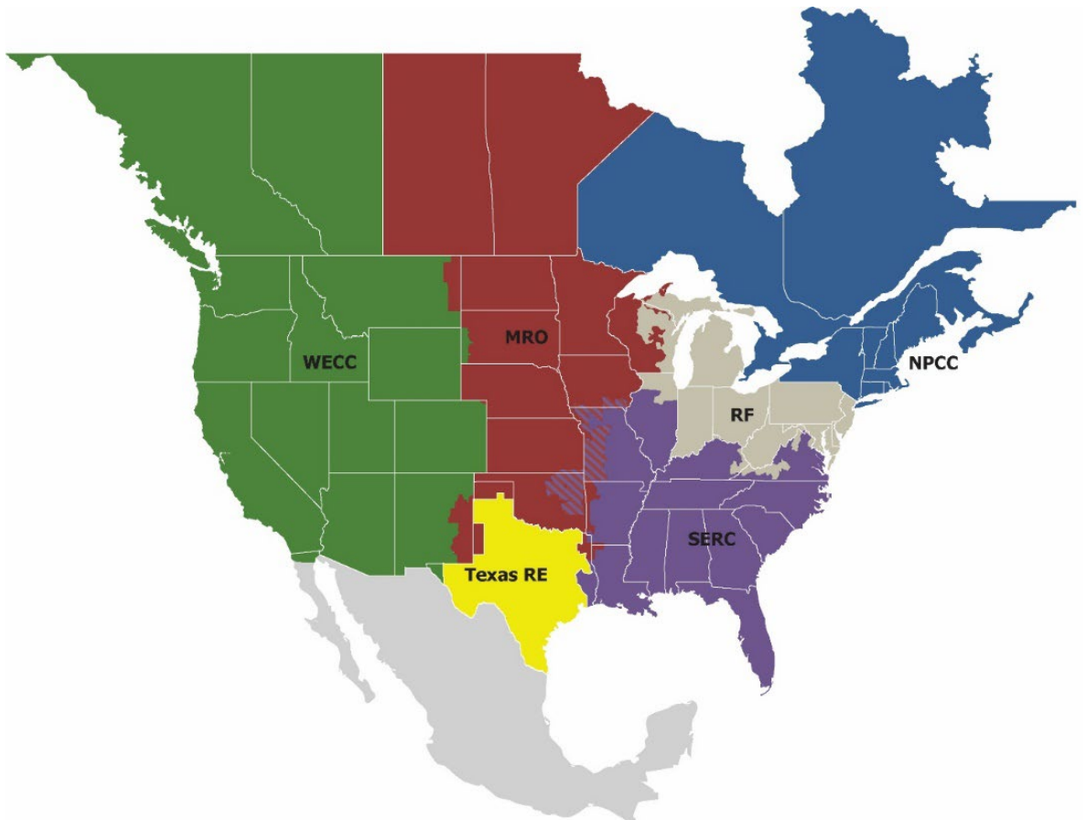
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

The *Long-Term Reliability Assessment* (LTRA), along with NERC's other reliability assessments and analysis reports, supports the ERO Enterprise vision and mission by providing independent analysis of reliability risks. Other important assessments and reports include the following:

- **Seasonal Reliability Assessments:** The *Summer Reliability Assessment* (SRA) and *Winter Reliability Assessment* (WRA) provide overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected seasonal peak demands. They also identify reliability issues of interest and areas of concern for the upcoming season. Seasonal assessments are published annually prior to each respective season.
- **Special Reliability Assessments:** In addition to the long-term and seasonal reliability assessments, NERC also conducts special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the NERC Board of Trustees or governmental authorities. Special reliability assessments are performed and published on an as-needed basis.
- ***State of Reliability* Report (SOR):** The SOR contains an unbiased, data-driven look at BPS reliability for the calendar year, identifying ongoing challenges and informing future-looking reliability assessments. It seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describe the actions that the ERO Enterprise has taken, and will take, to address them. The SOR is published annually, containing analysis of BPS performance data from the prior year.
- **Event Analysis Reports:** NERC publishes reports of major system events and off-normal system occurrences as one output of the ERO Event Analysis Program. This program employs rigorous post-event analysis and promotes broad understanding of the causes and effects of reliability events. NERC also publishes Lessons Learned for industry.

Reliability assessments and analysis are published on NERC's website.

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the LTRA annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2025 about known system changes with updates incorporated prior to publication. This *2025 LTRA* assessment period includes projections for 2026–2035; however, some figures and tables examine data and information for the 2025 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment, which is primarily focused on resource adequacy and operating reliability. NERC leads a multifaceted approach through its Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry and government partners.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

Assumptions

In this *2025 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts that were submitted and validated in July 2025. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame has been included where appropriate.
- Peak demand is based on average peak weather conditions and forecasted economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, known planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading This Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability, with a special focus on adequacy in the first five years
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[5] ERO Reliability Assessment Process Document

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

The overall resource adequacy outlook for the North American BPS is worsening: In the *2025 LTRA*, NERC finds that 13 of 23 assessment areas face resource adequacy challenges over the next 10 years. Projections for resource and transmission growth lag what is needed to support new data centers and other large loads that drive escalating demand forecasts. Most new resources in development to come on-line in the next five years consist of battery storage and solar photovoltaic (PV), which are inverter-based and weather-dependent resources that increase the complexity of planning and operating a reliable grid. Meanwhile, more fossil-fired generator retirements loom in the next five years, reducing the amount of generation that has fuel on site and impacting the system's ability to respond to spikes in demand. The continuing shift in the resource mix toward weather-dependent resources and less fuel diversity increases risks of supply shortfalls during winter months. As Resource Planners, market operators, and regulators grapple with steep increases in demand and swelling resource queues, they face more uncertainty, adding to the already-complex endeavor of planning for resource adequacy during this period of rapid grid transformation. To ensure there are sufficient resources for supplying electricity in the future and to reliably meet the growing electricity needs for North Americans, industry, regulators, and policymakers need to be vigilant for shifting projections, keep plans for deactivating existing generators flexible, expedite system development, and perform robust adequacy assessments of future scenarios. In addition, careful planning and broad cross-sector coordination will be needed to navigate a period of potentially strained electricity resources.

The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions based on current BPS planning forecasts. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used a probabilistic assessment and a deterministic reserve margin analysis from the LTRA process to identify the risk of future electricity supply shortfall and determine a risk category for each assessment area based on consistent risk criteria.[7] Risk assessment inputs are tied to industry forecasts of electricity supplies, demand, and transmission development, providing a forward-looking snapshot of resource adequacy.

Areas determined to be **High Risk** exceed the upper risk criteria levels. In high-risk areas, planned resources as of July 2025 would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load.[8] **Elevated-Risk** areas meet resource adequacy criteria, but planned resources are likely to result in energy shortfalls that are expected to be limited to more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, fuel supply disruptions, and limitations of normal electricity transfers. **Elevated-Risk** areas are identified in the LTRA when unserved energy and load loss metrics are below the **High-Risk** criteria but are not negligible. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions and are below the lowest risk criteria level. The results of the risk assessment are summarized for all elevated- and high-risk assessment areas in **Figure 1** and described in **Table 1**.

[7] In some cases, NERC modified the risk category when system studies performed by a system operator or regulator determine that resource adequacy target(s) will not be met. Details of the risk evaluation for each assessment area are in the **Capacity and Energy Risk Assessment**.

[8] The criteria used for risk determination in the LTRA include resource adequacy targets established by regulatory authorities, traditional 1-day-in-10 years load-loss criteria, and probabilistic loss-of-load-hour and expected unserved energy metrics. See **Risk Categories** in this report for a complete description.

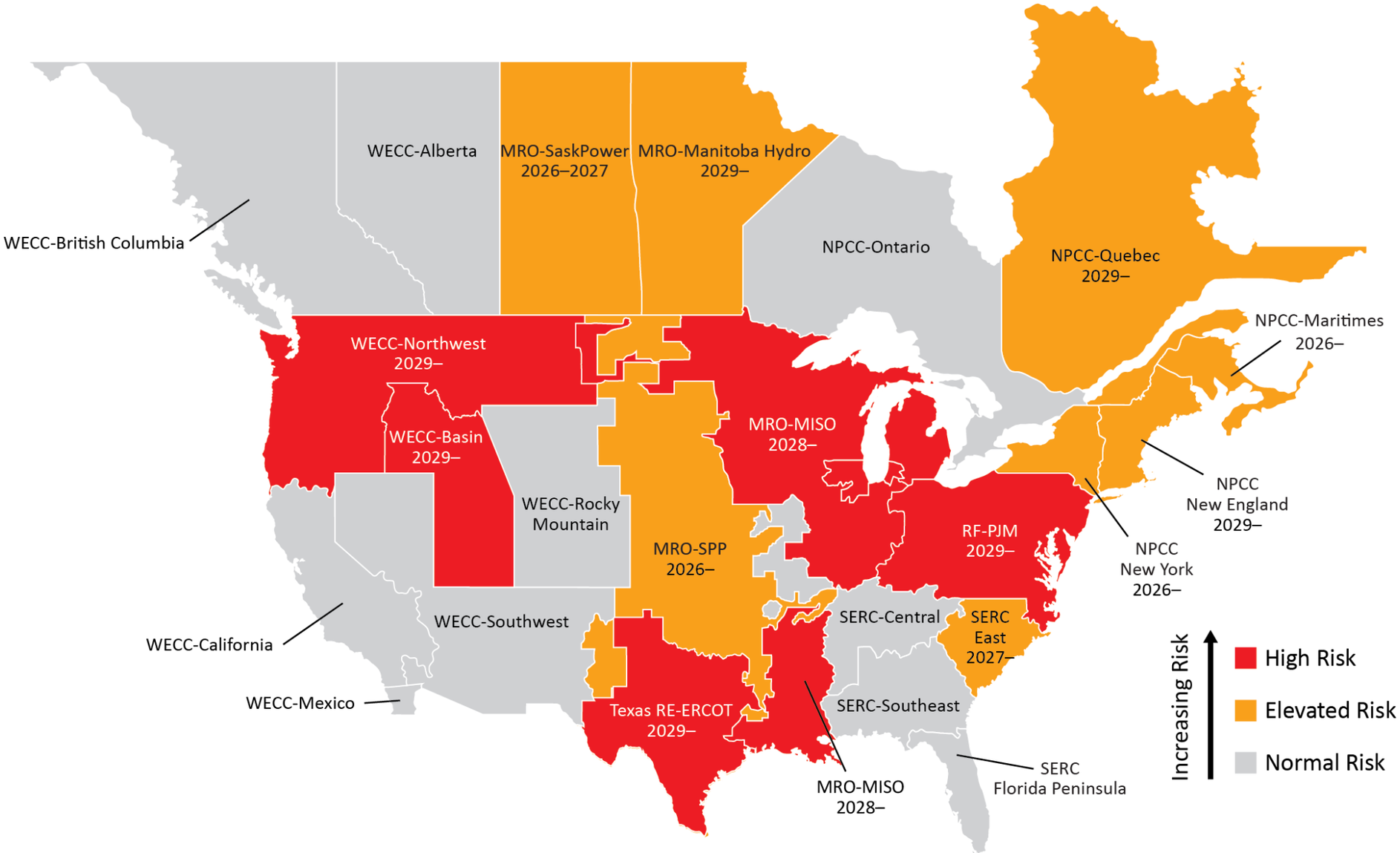


Figure 1: Risk Area Summary 2026–2030

Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

Table 1: Capacity and Energy Risk Assessment Area Summary

Assessment Area	Risk Level (High, Elevated, or Normal)					Risk Summary
	2026	2027	2028	2029	2030	
MISO						Projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements. The recently approved *Expedited Resource Addition Study* (ERAS) process is expected to result in additional resources in the MISO system beginning in 2028 that are not included in the model for the *2025 LTRA*. Timely implementation of ERAS resources will eliminate reserve margin shortfall and improve expected unserved energy metrics.
MRO-Manitoba						With rising demand, planned reserves are falling, leading to potential resource shortfalls in low-hydro conditions.
MRO-SaskPower						With current resources, there is risk of insufficient generation during fall and spring when more generators are undergoing maintenance. Expected natural-gas-fired generator additions in Winter 2027 will boost planned reserves and reduce risks of unserved energy.
MRO-Southwest Power Pool (SPP)						Demand forecasts outpace resource additions, leading to falling reserve margins. Scenarios with low wind and high generator forced outages identify energy shortfall risks. SPP's *Expedited Resource Adequacy Study* is attracting additional resources.
NPCC-Maritimes						Demand growth forecasts have increased since the *2024 LTRA*, while expected capacity contributions from variable energy resources (VER) have declined, causing resource shortfalls in the near term. New natural-gas-fired generation planned for 2028 will reduce the potential unserved energy, but not below the elevated risk threshold.
NPCC-New England						Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of energy shortfalls in extreme winter conditions.
NPCC-New York						Planned retirements of peaking generators create localized system adequacy needs as described in the New York ISO *2025 Q3 Star Report*.
NPCC-Québec						Demand growth projections are outpacing planned resource additions, leading to projected resource shortfalls in the winter season.
PJM						Current projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements. The anticipated resource margin falls below the Reference Margin Level starting in 2029. Recently approved new generation projects for expedited interconnection under the PJM Reliability Resource Initiative were not far enough along to include in the LTRA risk analysis.
SERC-East						Current projections for resource additions do not keep pace with escalating demand forecasts and planned generator retirements. With projected resources, supply shortfalls would occur in below-normal winter temperatures, resulting in unserved energy.
Texas RE-ERCOT						Probabilistic unserved energy metrics for 2026–2027 have improved since the *2024 LTRA*, but continued rapid load growth outpaces projected resource additions in later years. To mitigate increasing resource adequacy risks from load growth, Texas lawmakers have granted ERCOT operators additional authority to curtail new large loads if necessary to prevent grid emergencies. Texas lawmakers also established funding programs to expedite new resources that address reliability needs.
WECC-Basin						Demand forecasts outpace resource additions and expected generator retirements, leading to falling reserves. Resource additions nearing completion are predominantly solar PV, leading to a more variable resource mix. Unserved energy risk is in summer.
WECC-Northwest						Rapid forecasted demand growth is driving the need for more resources. Resource additions nearing completion are predominantly solar PV, battery, and wind, leading to a more variable resource mix. Periods of unserved energy are projected for both summer and winter.

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 23 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Responding to Trends in Resource Adequacy

As resource adequacy concerns have expanded and grown more acute in many parts of the North American BPS, more actions have been taken by industry and regulators to bolster resources.

- Projected retirements have shrunk from the *2024 LTRA*. Growing demand, market signals, and resource plans have highlighted the potential need to keep resources on-line longer than previously anticipated. Though the confirmed and announced potential retirements over the next 10 years remain high and total over 105 GW in peak seasonal capacity, this is roughly 10 GW lower than the 10-year retirement projections last year.
- The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Market procurements are becoming more effective in procuring resources as a result.
- Expedited resource programs that were approved by FERC in late Summer 2025 for MISO, PJM, and SPP have resulted in acceleration and prioritization for resources that can address identified reliability risks. Most new resources brought in through recently approved expedited resource programs are not included in the *2025 LTRA* risk assessment.
- Lawmakers in Texas have provided ERCOT with curtailment management authority over new large loads to prevent grid emergencies and established funding to speed new generating capacity to the grid.

The **Capacity and Energy Risk Assessment** and **Regional Assessments Dashboards** sections provide details on these examples and initiatives in other assessment areas.

Trends and Reliability Implications

Demand, resource, and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends and Implications

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter peak demand is expected to grow by 245 GW, continuing to outpace summer and exceed prior-year projections. New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.

Demand and large-load projections throughout the LTRA are based on load-serving entity (LSE) and BPS system planner forecasts provided to NERC during LTRA development, reflecting mid-2025 plans. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Still, large loads inherently add volatility to load forecasts as project timelines and commitments can vary with factors related to construction, permitting approvals, grid development, and data center owner decisions. ERCOT and PJM, the grid planners and operators for two areas experiencing vigorous large-load and data center development, have each prepared revised load forecasts since the *2025 LTRA* data collection period that, due to timing, is not used in this LTRA. Both forecasts indicate that some large-load projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Load forecasts that are revised downward can shrink the energy shortfalls that are projected in this LTRA.

Resource Additions and the Changing Resource Mix

The shift toward a more variable resource mix continues, as battery, solar PV, and hybrid generation lead the most recent and projected near-term additions and as fossil-fired generators retire. From 2024 to 2025, the existing capacity from fossil-fueled generators fell by 21 GW, while BPS capacity for peak demand hours from battery, wind, and solar resources increased by 23 GW.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and, together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year's 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown modestly since

the *2024 LTRA* by 7 GW (1.7%). This is slightly less than in the prior year when Tier 1 and Tier 2 capacity grew by 44 GW.

As older fossil-fired generators retire and are replaced by more battery and solar PV resources, the resource mix is becoming increasingly variable and weather-dependent. The share of VERs in the existing BPS on-peak resource capacity increased from 9.5% to 10.2% over the last year. VERs have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. Frequency response, or the ability of the BPS to maintain stable frequency, is one such ERS that NERC assesses on an Interconnection basis to ensure future resource mix reliability. Battery storage can enhance system frequency response. Other IBRs provide little or no frequency response capability, requiring grid operators to ensure that enough synchronous generators and other facilities are on-line for system stability. This year's LTRA finds that the future resource mix in each Interconnection through 2027 has sufficient resource types to provide for adequate frequency response. As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

The thermal generation component of the resource mix is increasingly reliant on natural gas for fuel as new natural-gas-fired generators are added to the BPS and as some existing coal-fired generators undergo fuel conversion. Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years: 53 GW of new natural-gas-fired winter capacity is in the planning queues, and new ERAS programs will add more. As new natural-gas-fired generators progress through interconnection processes, Generator Owners, grid planners, and natural gas infrastructure developers need to take steps to ensure that regional natural gas infrastructure can reliably serve the needs of BPS generators.

Transmission Development and Interregional Transfer Capability

Transmission projections reported for the *2025 LTRA* reflect an increase in transmission development, continuing a trend that emerged in the *2024 LTRA*. This year's cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years is substantially higher than the *2024 LTRA* 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially over past-year levels; rather, the large increase in transmission projects is seen in planning phases. Several Planning Coordinators (PC) have recently approved, or are actively contemplating, expansive extra-high voltage (EHV) overlays on their systems to address new generator additions and a variety of reliability needs, including Hydro-Québec, ERCOT, SPP, MISO, PJM, BC Hydro, and the Independent Electricity System Operator (IESO) in Ontario.

Interregional transmission projects that support energy transfers across Interconnections make up a small but important portion of total BPS transmission development. They can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,[9] including scenarios identified in the *Interregional Transfer Capability Study* (ITCS) published by NERC in 2024, and the separate ***Interregional Transfer Capability Study (Canadian Analysis)***. About 4% of transmission projects reported for the *2025 LTRA* are for tie-lines that support transfers between neighboring systems, lower than the 6% reported in the *2024 LTRA*.

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays. Other reasons for delays include economic impacts, planning and construction issues, permitting issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Expedite new resources to meet growing demand and carefully manage generator deactivations.** BPS planners should develop, implement, or enhance mechanisms to expedite resource additions to the grid that provide the services needed to address anticipated reliability issues related to each area's needs. Independent System Operator/Regional Transmission Organizations (ISO/RTO) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulators must support resource development and manage the pace of retirements such that replacement infrastructure can be developed and placed in service to support reliability needs.
2. **NERC, industry, and regulators: Understand and manage reliability risks accompanying large-load growth and leverage potential capabilities in new types of loads to provide flexibility to operators during times of grid stress.** An increasing number of large commercial and industrial

[9] Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission

loads is rapidly connecting to the BPS. Emerging large loads—such as data centers (including cryptocurrency and artificial intelligence applications) and hydrogen fuel plants—present unique challenges in BPS planning and operations. Stakeholders should support NERC's Large Loads Action Plan[10] and collaborate through NERC's Large Loads Task Force.[11] ISO/RTOs should collectively work to create more uniform requirements to address the emerging reliability issues associated with large data center loads.

3. **NERC, Regional Entities, and industry: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To promote consistency in analysis and develop assessment capabilities, NERC and the Regional Entities piloted Interconnection-wide energy assessments using a common probabilistic resource adequacy tool in 2025. Wide-area energy analysis will support the evaluation of interregional transfer capabilities and the effects of extreme weather and regional fuel supply issues on the BPS at an Interconnection level. Industry should work with NERC through its technical groups to implement ERO energy assessments in the *2026 LTRA* and continue to improve consistency in the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy.

4. **Regulators and policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, many states are also taking steps to expedite siting and permitting. Siting and permitting issues are among the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

5. **Regulators, electric industry, and gas industry member organizations: Continue identifying and implementing solutions for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** As various initiatives launched in past years roll out recommendations for addressing reliability needs, stakeholders should act with urgency on implementation. Continued collaboration through readiness forums and working groups remains a priority. While new regulatory and oversight mechanisms of the natural gas industry have yet to solidify, voluntary actions for managing natural gas production, processing, and delivery risks are needed. NERC, gas and electric industry, and research partners should continue studies and assessments of regional fuel supply risks to BPS generation.

6. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure that ERSs are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[12] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including VERs; however, policies and market mechanisms need to reflect these requirements to ensure that these services are provided and maintained. ISO/RTOs and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary.**

[10] NERC's Large Loads Action Plan: https://www.nerc.com/initiatives/large-loads-action-plan
[11] NERC's Large Loads Task Force webpage: Large Loads Task Force (LLTF)
[12] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Risk Assessment

Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure that sufficient resources are available to meet demand and prevent unacceptable levels of energy shortfall. In their application, traditional capacity-based adequacy criteria were not designed to consider the magnitude, frequency, duration, and timing of potential energy shortfalls. Such considerations have become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. NERC's LTRA includes all-hours probabilistic indices to measure these additional dimensions of risk and provide a more complete analysis to inform system plans.

Assessment Approach

NERC evaluates industry-provided resource adequacy data and credible studies to assess risks of future energy shortfalls as the system is currently planned. Probabilistic and deterministic analyses provide forward-looking snapshots of resource adequacy tied to industry forecasts of electricity supplies, demand, and transmission development. The risk analysis entails these components:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high risk periods and potential energy constraints resulting in load-loss events. The 2025 ProbA is performed for each assessment area and examines the system as planned for the years 2027 and 2029. Loss-of-load hours (LOLH) and expected normalized unserved energy (NEUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as the Reference Margin Level (RML)) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

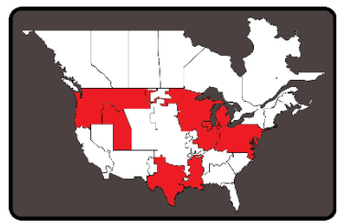
NERC also incorporates other findings from scenarios or information from system studies to address assessment area-specific adequacy risks when needed. See MRO-SPP, NPCC-New England, and NPCC-New York.

The risk determination is based on data and information provided to NERC during LTRA development and represents a snapshot in time. Integrated resource planning and ISO/RTO resource adequacy mechanisms vary across North America and can be implemented to respond to resource adequacy issues on many different timescales.

The **Demand Assumptions and Resource Categories** section provides further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

For the *2025 LTRA*, NERC uses the following three levels of risk category determination for each assessment area and associated years for which there is a risk of energy shortfall during the first five years of the LTRA period (i.e., 2026–2030). The details for the risk criteria determination are shown below for each category of risk.



An assessment area is determined as **High Risk** when established resource adequacy targets or requirements are not met or when probabilistic or deterministic energy analyses find that planned resources produce shortfalls resulting in unserved energy or load loss exceeding criteria for baseline resource adequacy specified below. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun to consider or develop resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[13] High risk areas are those where today's demand forecasts and resource projections indicate a shortfall in future planned resources for expected (i.e., most likely, aka 50/50) demand and typical resource performance. More severe operating conditions associated with unusual heat waves or deep-freeze events would further exacerbate shortfalls in planned resources.

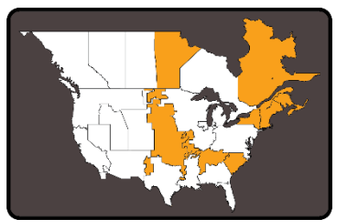
For the *2025 LTRA*, NERC uses the following criteria to determine areas and associated years for which there is high risk of insufficient planned resources during the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA; or
- Annual normalized expected unserved energy (EUE) exceeds 0.002% (20 ppm) for one or more years in the ProbA; or

[13] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

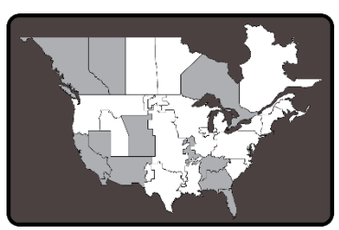
- Resource adequacy target(s) established by regulatory authority or system operator are not met.

Resource Planners, regulators, and market operators in assessment areas identified as having a high risk of resource shortfalls can mitigate these risks through timely actions that address capacity and energy risks.



An assessment area is determined to have **Elevated Risk** when it meets the established resource adequacy targets and baseline criteria specified earlier but does not meet more stringent thresholds of unserved energy and load loss that provide for reliability in more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. For the *2025 LTRA*, assessment areas are classified as elevated risk when they meet any one of the following criteria in the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA
- Annual normalized EUE is less than 0.002% (20 ppm) but greater than or equal to 0.0002% (2 ppm) for one or more years in the ProbA
- Resource adequacy target(s) established by regulatory authority or system operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions indicate risk of loss of load



An assessment area is determined to have **Normal Risk** if resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas determined as normal risk are expected to have sufficient resources for plausible extreme[14] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2025 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is below 0.0002% (2 ppm).
- Resource adequacy target(s) established by regulatory authority or system operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from the ProbA performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In last year's LTRA, NERC incorporated new probabilistic assessment risk criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report, *Evolving Planning Criteria for a Sustainable Power Grid*, alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

A numerical summary of the assessment areas' risk profile measured against the NERC risk criteria is summarized in **Table 2**. A risk description summary for each assessment area at an **Elevated Risk** or a **High Risk** is provided in the **High-Risk Area Details** or **Elevated-Risk Area Details** sections following **Table 2**. Full details about all assessment areas are provided in the **Regional Assessments Dashboards** section.

[14] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide-Area Heat Dome.

Table 2: Capacity and Energy Risk Assessment Numerical Summary														
	NEUE (ppm)		LOLH (hours/year)		Anticipated Reserve Margin					Reference Margin Level[15]				
Summer-Peaking Areas	**2027**	**2029**	**2027**	**2029**	**2026**	**2027**	**2028**	**2029**	**2030**	**2026**	**2027**	**2028**	**2029**	**2030**
MISO	1.13	**42.39**	**0.23**	**6.61**	11.0%	11.2%	9.5%	8.6%	**4.3%**	8.1%	8.3%	8.5%	8.5%	8.5%
MRO-SPP	0.00	0.00	0.00	0.00	32.4%	30.3%	28.4%	25.1%	22.6%	19.0%	19.0%	19.0%	19.0%	19.0%
NPCC-New England	0.00	0.02	0.00	0.00	18.3%	21.7%	24.8%	23.7%	23.6%	13.4%	13.0%	13.0%	13.0%	13.0%
NPCC-New York	0.00	0.08	0.00	0.03	22.3%	24.5%	24.5%	23.6%	22.5%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Ontario	0.00	0.00	0.00	0.00	29.6%	19.8%	28.1%	18.7%	19.7%	16.1%	19.0%	22.6%	15.8%	19.5%
PJM	**3.50**	**65.50**	**0.61**	**9.97**	29.7%	28.3%	24.3%	**18.9%**	**13.9%**	18.6%	20.1%	21.9%	23.9%	26.3%
SERC-Central	0.00	0.00	0.00	0.00	19.1%	20.8%	19.7%	18.5%	16.5%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-East	0.98	**2.27**	**0.15**	**0.33**	30.6%	30.5%	30.5%	31.5%	34.9%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Florida Peninsula	0.00	0.00	0.00	0.00	27.4%	25.2%	24.3%	22.6%	21.1%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Southeast	0.00	0.00	0.00	0.00	35.9%	29.5%	29.8%	24.9%	20.9%	15.0%	15.0%	15.0%	15.0%	15.0%
Texas RE-ERCOT	**8.70**	**18.84**	**0.95**	**3.64**	28.2%	30.5%	31.8%	30.8%	29.9%	13.8%	13.8%	13.8%	13.8%	13.8%
WECC-Basin	0.04	**2,250**	**3.00**	**310.00**	36.3%	37.9%	27.4%	19.7%	15.2%	13.5%	14.0%	13.6%	12.4%	12.3%
WECC-California	0.00	0.00	0.00	0.00	53.2%	47.0%	46.1%	45.6%	42.7%	20.3%	19.2%	19.3%	19.7%	19.3%
WECC-Mexico	0.00	0.00	0.00	0.00	14.9%	13.8%	29.9%	27.0%	24.6%	7.8%	8.0%	9.1%	7.2%	7.0%
WECC-Rocky Mountain	0.00	0.00	0.00	0.00	51.3%	60.0%	53.2%	38.1%	30.5%	17.8%	17.0%	16.2%	16.1%	15.7%
WECC-Southwest	0.00	0.00	0.00	0.00	41.1%	39.6%	38.6%	38.4%	36.1%	13.3%	13.7%	13.6%	12.6%	12.2%
Winter-Peaking Areas	**2027**	**2029**	**2027**	**2029**	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
MRO-Manitoba Hydro	0.12	0.23	0.03	0.06	13.9%	16.7%	15.4%	13.6%	**1.2%**	12.0%	12.0%	12.0%	12.0%	12.0%
MRO-SaskPower	**5.24**	0.19	**1.09**	0.05	25.9%	35.0%	33.4%	32.3%	31.2%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Maritimes	0.52	0.25	**0.25**	0.10	**17.2%**	**18.5%**	25.6%	23.0%	21.7%	20.0%	20.0%	20.0%	20.0%	20.0%
NPCC-Québec	0.00	0.29	0.00	**0.11**	15.6%	16.7%	14.7%	13.0%	**11.5%**	11.9%	12.2%	12.2%	12.2%	12.2%
WECC-Alberta	0.00	0.00	0.00	0.00	36.2%	45.3%	40.7%	38.0%	33.0%	11.8%	17.6%	14.3%	15.6%	11.6%
WECC-British Columbia	0.00	0.00	0.00	0.00	23.4%	19.1%	19.5%	24.1%	24.2%	11.7%	12.1%	12.1%	11.6%	11.6%
WECC-Northwest	0.00	**36.64**	0.00	**85.00**	30.2%	29.3%	23.3%	19.1%	15.7%	17.8%	17.4%	16.1%	15.8%	15.5%

[15] Refer to the Regional Assessments Dashboards and the Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area table.

High-Risk Area Details

The assessment areas below exceed the highest level of risk criteria for the **High-Risk** classification during one or more years of the 2026–2030 period. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MISO (Normal Risk 2026| Elevated Risk 2027| High Risk 2028–)

Escalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area. MISO forecasts its peak total internal demand at 127 GW during the 2026 summer season (up over 2.6 GW since the same year's projection in the *2024 LTRA*) and expects that summer demand will grow to 143.7 GW by 2035. The largest contributor to this accelerated demand growth is data center additions with 18 GW of data center loads projected by 2035. MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements. New solar PV resources contribute to a 5.7 GW increase in MISO's accredited non-thermal capacity since last year.

As of July 2025, MISO has more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity. In addition to these resources, MISO instituted the ERAS process to respond to generation needs. The ERAS process provides a framework for the accelerated study of generation projects that address urgent resource adequacy and reliability needs in the near term. ERAS projects are not in the model for the *2025 LTRA*. If ERAS projects come in as currently planned, the projected reserve margin shortfall would be eliminated.

Based on the current resource and demand forecasts, MISO begins to meet elevated-risk criteria in 2027 (see **Table 3**). While resources are adequate for regulatory requirements, the ProbA results show load loss and unserved energy exceeding the elevated-risk threshold. The Summer season makes up the bulk of annual risk in this region and is seen to materialize during late afternoon and evening hours when demand is high and solar resource output begins to decline. The ProbA also identifies winter risk periods during early morning and hours after 7:00 p.m. Additionally, shortfall risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.

As the demand forecast rises in subsequent years, and with currently projected generator retirements and planned resource additions, the ProbA shows worsening results. While resources are adequate for regulatory requirements (i.e., loss of load expectation (LOLE) of 0.1 day in a year), the ProbA results show load loss and unserved energy exceeding the elevated risk threshold criteria.

For the 2029 ProbA study, MISO assumed 14 GW of generator retirements that are uncertain to occur by 2029.

Table 3: MISO Base-Case Summary of Results

	2027	2029
EUE (MWh)	797	31,654
NEUE (ppm)	1.13	42.39
LOLH (hours per Year)	0.23	6.61
Category	Elevated	High

With model assumptions, MISO would exceed load-loss and unserved energy criteria and fall below reserve margin targets to become a high-risk area beginning in Winter 2028 (see **Figure 2**). Projections for resource additions are predominantly solar PV, with some battery and wind resources. The small amounts of natural-gas-fired generation in signed interconnection agreements do not offset planned generator retirements, and, as a result, MISO is projecting shortfalls in planned resources for winter peak periods.

These results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and can work to address uncertainties associated with these three phenomena.

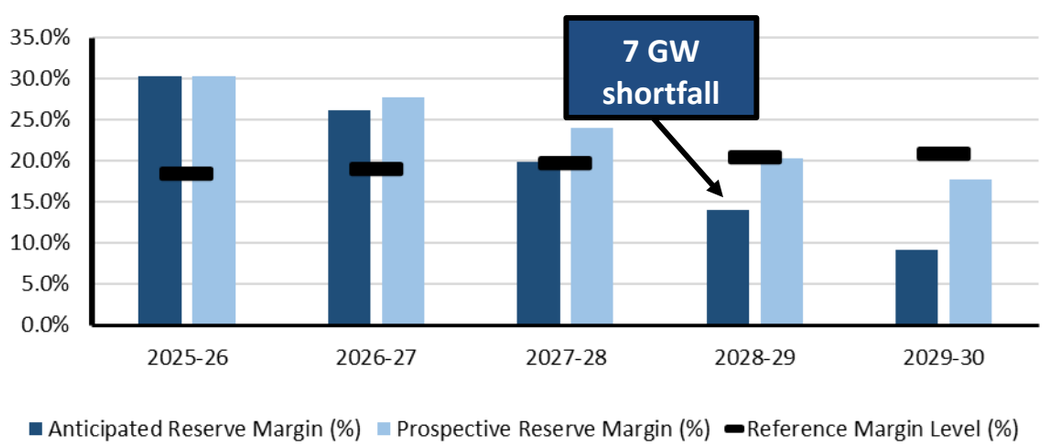
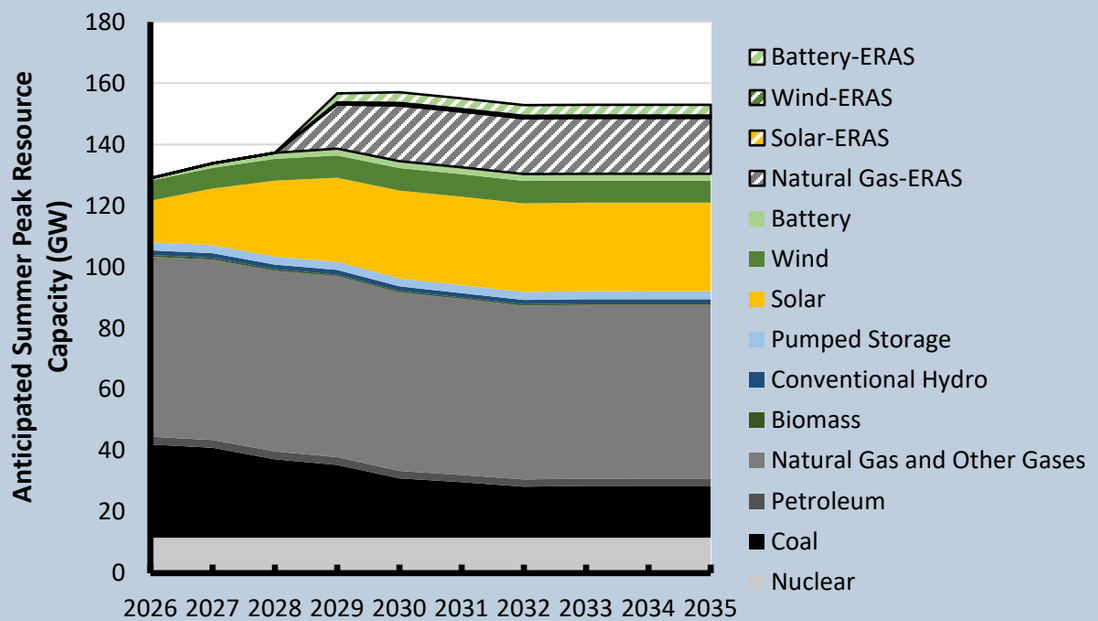


Figure 2: MISO Winter Planning Reserve Margins

Currently, MISO has surplus transfer capacity within its assessment area, but transfers between subregions have been historically constrained by a transmission limitation between the northern and southern MISO subregions.

The timing of FERC's approval of MISO's ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the *2025 LTRA*. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from ERAS is expected to grow to over 20 GW by summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year's ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the *2026 LTRA*, and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



The Potential Effect of MISO's ERAS Process on Anticipated Summer Capacity

PJM (Elevated Risk 2026–2028| High Risk 2029–)

Demand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads. PJM expects its summer peak demand to grow by 56 GW to a total of 210 GW in 2035, and its winter peak demand is expected to climb by 62 GW to reach 198 GW by winter 2034–35. PJM's annual net energy for load growth rate is projected to average 4.8% per year over the next 10 years, up from 2.3% in last year's projections.

At the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays. A large share of PJM's new interconnection requests is from VERs, approximately 40% of which are solar, and dispatchable resources are currently leaving the system faster than they can be replaced with other dispatchable technologies. These factors, paired with PJM's limited reliance on transfers from neighboring areas to meet resource adequacy targets (maximum total transmission interchange capability is <2% of PJM's internal generation capacity), have led to a projection that PJM's ARM may fall below its Installed Reserve Requirement (or RML) in 2029 (see **Figure 3**).

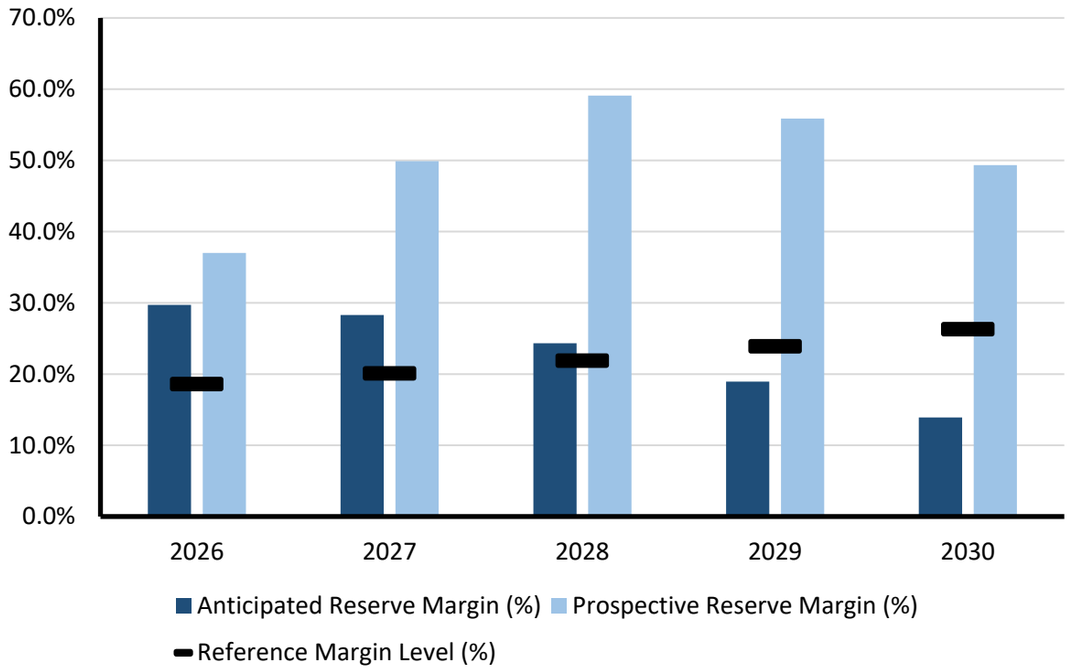


Figure 3: PJM Summer Planning Reserve Margins

As part of its reforms to speed interconnection with the system, PJM has approximately 30,000 MW of generation projections in the transitional interconnection queue to be processed in 2026. PJM's new cycle process opens in April with a one- to two-year timeline for reviews, depending on the impact to the system. From the time of the original *2025 LTRA* data submittal to recent evaluation, PJM projected an additional 8.3 GW of Tier 1 summer resource capacity over the next seven years. Tier 1 resource additions will provide 3.4 GW of winter capacity. However, many of these projects continue to be slowed or stopped by factors affecting multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges or financing.

In 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative (RRI), which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original *2025 LTRA* data submittal and 4.1 GW in winter capacity. This net increase factors resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

Setting aside the impact of such initiatives, results of the ProbA using PJM's current resource and demand forecasts indicate that the area is at an elevated risk of resource shortfalls at the beginning of the 10-year horizon (see **Table 4**). Because this year's ProbA does not study years earlier than 2027, the elevated-risk determination is based on results of the 2024 ProbA and consideration of the declining ARM in PJM since last year's LTRA (2026 Summer ARM has fallen from 35.7% to 29.7%). The greatest risk of resource shortfalls leading to unserved energy or load loss in PJM occurs in the winter months during the early morning and evening hours. The risk is associated with generator availability and performance issues that can arise from equipment freezing and fuel supply issues during extreme winter conditions. PJM falls into the high-risk category beginning in 2029 as demand forecasts continue to climb, generators reach planned retirement dates, and the projected resources become less certain. The winter risk profile indicates that new resources will need to be capable of reliably serving winter load.

Table 4: PJM Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	538	3,251	67,581
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.1	0.61	9.97
Category	Elevated	Elevated	High
***Provides the 2024 ProbA Results for Comparison**			

Texas RE-ERCOT (Elevated Risk 2026–2028| High Risk 2029–)

The Texas RE-ERCOT assessment area is forecast to experience continued rapid electric demand growth over the next 5–7 years. ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads totaling 45 GW by 2030, of which 23 GW are data centers.

ERCOT continues to evolve its planning methods as fluctuations in recent large interconnections activity continue to affect both near- and long-term demand expectations. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Such fluctuations do not, however, undercut the significance of demand growth attributable to large loads.

Responding to rapidly escalating demand from data centers and other large industrial loads, ERCOT, regulators, and lawmakers in Texas are adapting with policy and planning approaches to address emerging supply risks. Actions provide ERCOT with new curtailment management tools for large loads, establish criteria for when to incorporate new large loads in system planning, and help fund and speed new generating capacity to the grid. Furthermore, the first reliability assessment for the Public Utility Commission of Texas (PUCT)-approved Reliability Standard, and potential approval of market design changes to address deficiencies, is scheduled for completion by year-end 2026. Such market design changes would further mitigate energy risk.

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and provide ERCOT authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. For the *2025 LTRA*, ERCOT's DR contributions have increased substantially to reflect the authority and capability to curtail new large loads during energy emergencies. For Summer 2026, DR contributes 13.3 GW to resource adequacy (up from the 2.7 GW projection in the *2024 LTRA*), and contributions from DR rise to 53.1 GW by 2030. Because new large loads can be curtailed during energy emergencies, the rapid rise in projected large loads has substantially less effect on Planning Reserve Margins in ERCOT than in the 2024 LTRA.

The ARM is above the 13.75% RML for all years (see **Figure 4**).

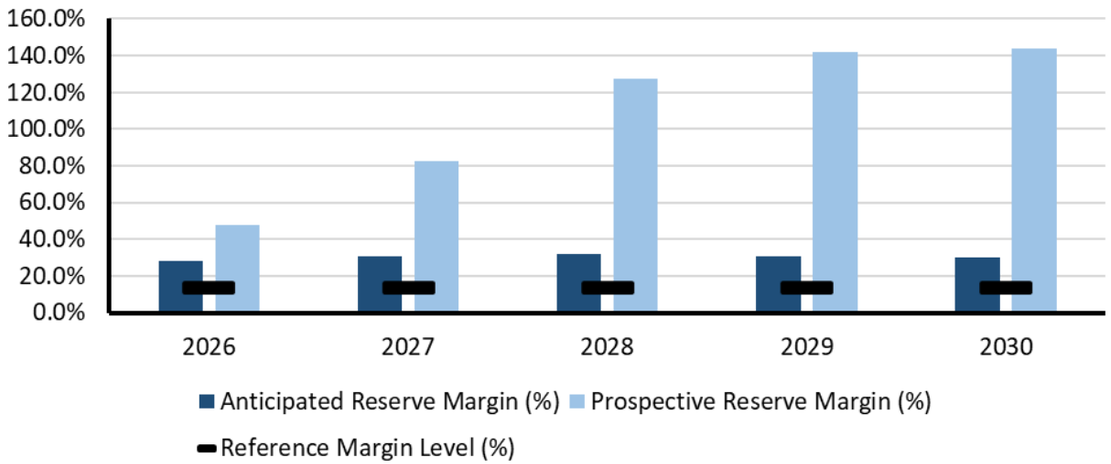


Figure 4: TEXAS RE-ERCOT Summer Planning Reserve Margins

ERCOT's Planning Reserve Margins in the *2025 LTRA* are also being affected by the implementation of new capacity contribution methods. ERCOT has switched from using historical average on-peak capacity factors to average effective load carrying capabilities (ELCC) for VERs, and the resulting capacity derates largely offset the gains that load management programs have on ARM. In the case of solar, ELCCs are significantly lower than prior years. ELCC values are probabilistically derived and reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low.

The ProbA results for Texas RE-ERCOT reveal some improvement in near-term resource adequacy when compared to the *2024 LTRA*, but the area remains an elevated risk through 2027 before forecasted load growth drives the area to high risk (see **Table 5**). ERCOT's ProbA modeling includes demand-side management protocols that reasonably reflect large load curtailments described above, and other programs used in ERCOT's market. This modeling contributes to the improved unserved energy and load-loss hour metrics that are observed between the 2024 ProbA and the current ProbA. Battery resource additions since last year and improved modeling in the resource adequacy analysis tool also contribute to these improved metrics.

Table 5: Texas RE-ERCOT Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	11,090	5,865	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.95	3.64
Category	Elevated	Elevated	High
***Provides the 2024 ProbA Results for Comparison**			

ERCOT's ProbA study results show that most resource adequacy risk is in the winter, and this is mainly driven by the large demand variability associated with winter temperatures. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year. For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours (peaking at hour ending (HE) 9:00 p.m.) based on probabilistic capacity reserve modeling for monthly peak load days. During these periods, the drop-off in solar generation causes margins to decrease when load remains high. Battery storage helps reduce these short-duration energy risks. ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026 (Existing and Tier 1 resource categories) and grow to 25.2 GW by 2029. ERCOT typically sees the greatest energy provided by energy storage during net load peaks when solar is ramping off in the evening, or during early morning hours prior to solar ramping up.

In response to the rapid and unprecedented load growth, the PUCT in April 2025 approved three 765 kV import paths identified in the *Permian Basin Reliability Study*, which introduced the new 765 kV voltage class into the ERCOT region after six decades since the introduction of the 345 kV voltage class. The Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP) tackles the unprecedented load growth expected by 2030 and enhances transfer capability by an additional 600 MW to 3,000 MW. This 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers.

WECC-Basin (Elevated Risk 2026–2028/High Risk 2029–)

Forecasted load growth and planned generator retirements in the Great Basin (WECC-Basin assessment area) present resource adequacy challenges. Over the next 10 years, the summer demand forecast will rise by over 1.7 GW (17%, or 1.8% compounded annually), while at the same time the capacity from currently existing resources will decline by nearly 2.3 GW through generator retirements and other capacity changes. Solar resources are the predominant type nearing project completion: There is 3.5 GW of nameplate solar capacity (capable of providing 2.3 GW to summer capacity) in Tier 1 resources for the assessment period, making up nearly half of all resources in the

Tier 1 and Tier 2 planning.[16] The projected resources, with planned retirements and additions, are not sufficient for forecasted demand, resulting in some unserved energy and load-loss hours in the future-year energy analysis. While the ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH (see Table 6).

Table 6: WECC Basin Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2,250.70
LOLH (hours per Year)	N/A	3.00	310.00
Category	-	High	High
***No prior results as the assessment area is new for the *2025 LTRA*.**			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. ProbA results for 2027 indicate that risk is most concentrated to the month of peak demand and the hours around sunset as solar output declines. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime. In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in unserved energy and load-loss hours.

Unlike the ProbA results from other areas, WECC's probabilistic model produces values higher values for load loss and EUE because the results are not probabilistic weighted averages. Taking this into account, NERC assesses WECC Basin as an elevated risk through 2029 even though the reported load-loss hours from the simulations exceed high-risk criteria

WECC-Northwest (Normal Risk 2026–2028| High Risk 2029–)

Peak load in the WECC-Northwest assessment area is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest. There are over 10 GW of new wind, solar, and battery projects expected to connect over the next five years (nameplate capacity) and provide an expected on-peak capacity contribution in winter of 3.2 GW. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging. While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029 (see Table 7).

Table 7: WECC Northwest Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0.00	36.64
LOLH (hours per Year)	N/A	0.00	85.00
Category	N/A	Normal	High
***No prior results as the assessment area is new for the *2025 LTRA*.**			

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer.

Elevated-Risk Area Details

The below areas are classified as Elevated Risk as they are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the Regional Assessments Dashboards section.

MRO-Manitoba Hydro (Normal 2026–2028| Elevated 2029–)

The Winter 2026–2027 peak demand forecast grew by 127 MW, exceeding the projected 29 MW growth from the *2024 LTRA*. Demand growth is driven primarily by population growth and expected economic activity. Conversely, the forecasted annual peak demand growth rate for the next 10 years has fallen to almost 1.4%, down from around 1.8% projected in the *2024 LTRA*. Generating resources are projected to remain largely the same over the 10-year planning period.

Similar to prior probabilistic assessments, Manitoba Hydro's 2025 ProbA indicates elevated-risk levels of load loss in the later (year 4) study year (see Table 8). Resource adequacy concerns and load-loss risk in the ProbA arise from studied very low hydro conditions. Although the Manitoba system is

[16] Tier 1 resources in the LTRA are those resources in the interconnection process that have high confidence of being realized and generally under construction or have signed interconnection agreements. Tier 2 resources have more uncertainty in being realized and are in earlier development stages such as undergoing interconnection planning study.

winter-peaking, the risk is primarily present during the summer season, with some risk also identified in the spring shoulder season. Planned electricity supply resources could fall short during an extreme and prolonged drought, affecting the predominantly hydroelectric system.

Table 8: MRO-Manitoba ProbA Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	5	3	6
NEUE (ppm)	0.18	0.12	0.23
LOLH (hours per Year)	0.06	0.03	0.06
Category	Normal	Normal	Elevated
*** Provides the 2024 ProbA Results for Comparison**			

MRO-SaskPower (Elevated 2026–2027| Normal 2028–)

Large industrial loads in Saskatchewan are driving average annual peak demand growth of 1.0% compounded annually over the next 10 years, down slightly from the *2024 LTRA*'s projection (1.35%). To respond to demand growth, SaskPower recently added 370 MW of natural-gas-fired generation, 220 MW of VERs, and a 20 MW/20 MWh battery storage system to its system and is projecting on-peak resource additions of 700 MW over the next 10 years—a slight decrease from last year's projection (~1 GW). Nameplate additions include 400 MW of wind, 300 MW of solar, and 525 MW of natural gas to offset ~32 MW of confirmed waste heat recovery and wind generation retirements. Saskatchewan is also deferring generator retirements and reactivating recently deactivated coal units and is bolstering both its intra-regional and interregional transmission system to diversify its current portfolio that relies heavily on firm transfers with Manitoba. Reserve margins are expected to remain above SaskPower's RML for the entire 10-year period of the *2025 LTRA*.

SaskPower is a winter-peaking system, but MRO-Saskatchewan's probabilistic studies concluded that LOLH and EUE could occur during planned outages of large generators during peak demand hours in the spring and fall seasons. The ProbA reveals load-loss risk during the months of May, August, September, and October in 2027 based on current planned resources and load forecasts. Monthly and annual results improve in 2029 with SaskPower's projected resource additions (see **Table 9)**.

Table 9: MRO-SaskPower Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	76	145	5
NEUE (ppm)	2.81	5.24	0.19
LOLH (hours per Year)	0.55	1.09	0.05
	Elevated	Elevated	Normal
***Provides the 2024 ProbA Results for Comparison**			

MRO-SPP (Elevated 2026–)

Resource additions and delays in generator retirements since the *2024 LTRA* are improving the resource adequacy outlook for 2026, while higher demand forecasts and less capacity projects in development are causing lower planned reserves in later years. SPP's ARMs are projected to remain above RMLs until after 2030 (see **Figure 5**). Additionally, ProbA results of the planned resources and demand forecast did not identify EUE or load-loss hours in studied years. Seasonal resource adequacy assessments by NERC have identified risks of insufficient operating reserves during periods of low wind and high generator outages.[17] SPP is an elevated risk because it is projected to have lower planned reserves with a similar mix of VERs and dispatchable thermal generation in the future.

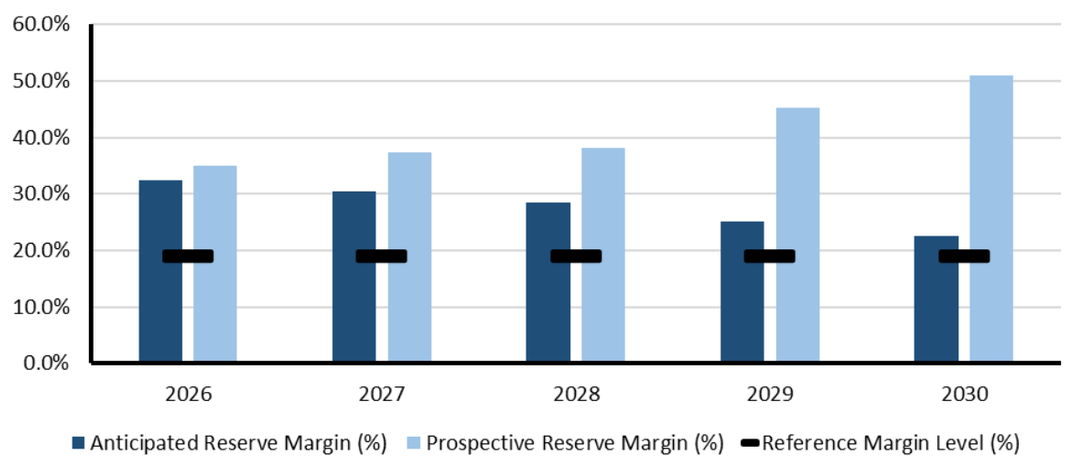


Figure 5: MRO-SPP Five-Year Planning Reserve Margin—Summer

[17] See NERC *2025 Summer Reliability Assessment*

Recent and newly approved resource adequacy initiatives in SPP are aimed at addressing demand growth and energy challenges associated with the evolving resource mix. SPP has approved higher Planning Reserve Margin requirements for LSEs that take effect beginning in the summer of 2026, along with a new winter reserve margin requirement starting later that year. These reserve margin requirements respond to growing resource adequacy challenges by obligating LSEs to obtain more firm resources for the summer and winter seasons. New performance-based resource accreditation will more accurately account for generator contributions to serving area demand during times of greatest need. The *Expedited Resource Adequacy Study* process, approved by FERC in July, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs.

NPCC-Maritimes (Elevated 2026–)

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period (see **Table 10**). This translates to compound average growth rates of 0.8% in summer and 1% in winter, which are higher than the *2024 LTRA* projections (0.4% in summer and 0.6% in winter). Resource projections for Maritimes have diminished slightly since the *2024 LTRA* due to smaller peak capacity contributions from certain VERs through most of the planning period.

Firm capacity transfers in the first two years of the assessment period (2026–2027 and 2027–2028) decreased significantly from the *2024 LTRA* (322 MWs to -32MWs in 2026 and 215 MWs to 75 MWs in 2027). As a result, the ARM is below the 20% RML in those years, 17.2% and 18.5%, respectively. Beginning in 2028, the capacity transfers for the remaining assessment period are consistent with those in the *2024 LTRA*, and ARMs are projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

Table 10: NPCC-Maritimes Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	5	15	7
EUE (ppm)	0.17	0.52	0.25
LOLH (hours per Year)	0.09	0.25	0.10
***Results from the 2024 The ProbA simulations**			

The ProbA for 2027 indicates elevated levels of unserved energy in the peak winter month of February. Load growth projections and resource mix characteristics are the primary driver. A few hours of risk occur in other winter months. Resource additions contribute to the improved EUE and LOLH metrics for the 2029 study year.

NPCC-New England (Normal 2026 –2028| Elevated 2029–)

Since the *2024 LTRA*, 650 MW of fossil-fired generation has retired in New England, while wind, battery, and solar projects and uprating to an oil-fired power plant are projected to increase summer capacity by 1 GW in Summer 2026. Winter capacity is also increasing by a similar amount due to the expected contribution of offshore wind by winter 2026–2027. New England is among the areas projecting the highest growth in winter electricity demand, with winter peak demand forecast to increase by 7.1 GW (36%) from the Winter 2025–2026 forecast over the next 10 years. This demand forecast has changed little since the *2024 LTRA*.

ProbA results and reserve margin assessment for the NPCC-New England Assessment Area indicate that the risk of unserved energy in New England is small (see **Table 11**). Unserved energy risk is concentrated in the summer months when area demand currently peaks. However, escalating winter electricity demand and the performance challenges faced by the current and future resource mix in extreme, long-duration cold weather events is a persistent reliability concern. New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. Interstate natural gas pipelines serving New England run at full capacity with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. An extended cold spell or a series of cold spells can threaten regional natural gas fuel delivery infrastructure and result in insufficient fuel for electric generators. Dual-fueled generation provides crucial alternative energy to maintain electric system reliability. In scenarios of extended extreme cold, stored liquid fuels can become depleted and result in insufficient generation for demand.

Table 11: NPCC New England Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	11	<1	2
NEUE (ppm)	0.10	0.00	0.02
LOLH (hours per Year)	0.10	0.00	0.00
Category	Normal	Normal	Normal
*** Provides the 2024 ProbA results for Comparison**			

NPCC-New York (Elevated 2026–)

The LTRA anticipated and Prospective Reserve Margins are above RML of 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the demand forecast with a greater risk added due to the variability in resource contribution. Demand could be 10–13% higher than expected, which could cause strain on the system.

This impact is shown in the increasing LOLH and EUE shown in **Table 12.**

Table 12: NPCC New York Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	2	<1	12
NEUE (ppm)	0.01	0.00	0.08
LOLH (hours per Year)	0.01	0.00	0.03
Category	Normal	Normal	Normal
*** Provides the 2024 ProbA results for Comparison**			

While NPCC's ProbA results and reserve margin assessment for the New York assessment area indicate that the risk of unserved energy in New York is relatively small, an assessment performed by NYISO, the ***2025 Quarter 3 Short-Term Assessment of Reliability*** **(STAR)**,[18] identified transmission security reliability needs in the New York City and Long Island parts of the system to ensure summer reliability. With little reliability margin, plausible futures point to system issues within the next 10 years. Depending on demand growth and retirement patterns, the system may need several thousand megawatts of new dispatchable generation over that time frame.

Due to the reliability needs identified in the STAR report, NERC assesses that NPCC-New York is an elevated risk area and that, with current resource and transmission system projections, localized supply shortfalls are likely in extreme conditions.

NPCC-Québec (Normal 2026–2028| Elevated 2029–)

Québec's demand forecast has increased since the *2024 LTRA*, driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Québec's demand peaks at 41.4 GW in 2026–2027, rising to 49.6 GWs by 2035–2036, an increase of 8.2 GWs compared to the assessment period growth of 7.5 GWs projected in the *2024 LTRA*.

With stable resources over the 10-year assessment period, Québec's ARMs remain above the 12.2% RML for the first four years, falling below in 2030–2031 and all subsequent years. Québec and Ontario have a firm seasonal capacity exchange agreement through 2030–2031 that allows Québec to import 600 MW in winter.

Hydro-Québec's Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and natural-gas-fired generation. These resources are not included in the present assessment due to their early development stage but are expected to be incorporated gradually into future assessments.

Hydro Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, EUE and LOLH are above the elevated risk criteria See **Table 13**.

Table 13: NPCC Québec Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	8	8	63
NEUE (ppm)	0.04	0.00	0.29
LOLH (hours per Year)	0.01	0.00	0.11
Category	Normal	Normal	Elevated
*** Provides the 2024 ProbA results for Comparison**			

SERC-East (Normal 2026| Elevated 2027–)

SERC-East is projecting over 5.7 GW of coal unit retirements over the 10-year assessment horizon. These continued retirements from prior years continue to trigger reserve margin targets and ProbA thresholds for elevated risk. To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years. The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years, as shown in **Table 14** below.

Table 14: SERC-East ProbA Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	143	232	539
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.15	0.33
Category	Normal	Elevated	Elevated
*** Provides the 2024 ProbA Results for Comparison**			

[18] Additional details available in the report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf/

Normal-Risk Area Details

All other assessment areas (see Figure 1) are classified as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The **Capacity and Energy Risk Assessment** section is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2025 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that the risk assessment map will expand with more elevated- and high risk areas in the future.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, petroleum, and nuclear generators can negatively affect the resource adequacy and reliability of the BPS in the next 10 years. In the preceding **Capacity and Energy Risk Assessment**, NERC accounted for nearly 92GW of nameplate of fossil-fired and nuclear generator retirements that are anticipated through 2035. NERC's risk analysis did not include an additional 65 GW of nameplate fossil-fired generators that have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. Combined, the confirmed and announced-potential retirements over the next 10 years total over 105 GW in peak seasonal capacity, roughly 10 GW lower than the 10-year retirement projections in the *2024 LTRA* (see **Figure 6**). Projected retirements overall, both confirmed and unconfirmed, have shrunk from the prior year's LTRA as reliability needs have expanded with the continued growth in anticipated large-load interconnections. The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Growing demand and evolving planning methodologies have highlighted the potential need to keep resources, particularly non-variable resources, on-line longer than previously anticipated.

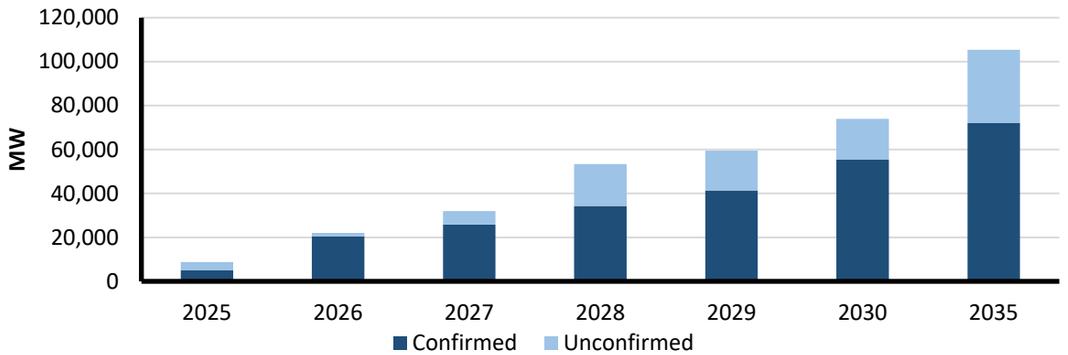


Figure 6: Projected Generation Retirement Capacity Through 2035

Figure 7 shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] MISO continues to lead the assessment areas in the amount of projected retiring capacity at roughly 35 GW.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from Additional Generator Retirements** section.

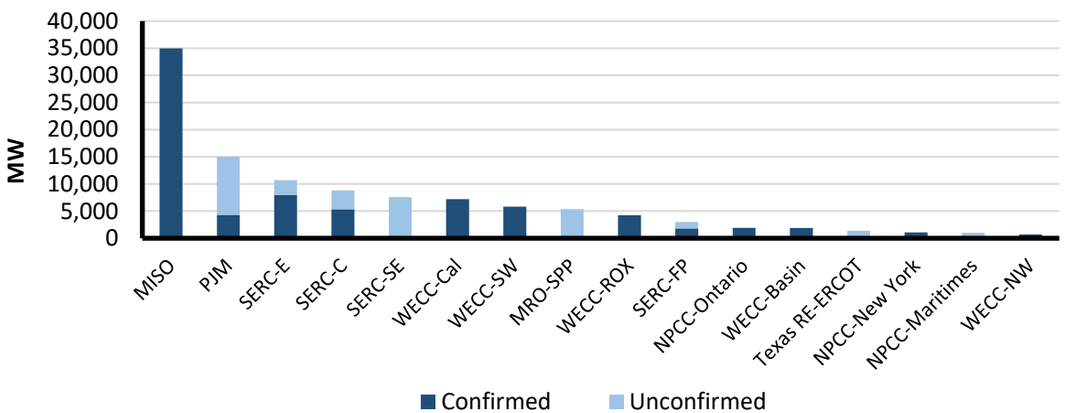


Figure 7: Projected Capacity Retirements of Nuclear and Fossil Generation 2025–2035

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2025 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the **Executive Summary**.

Resource Adequacy Program Attributes

Utilities, market operators, and regulators across North America are adapting their resource adequacy programs to address mounting challenges, including load growth, changing load behavior, resource mix transition, extreme weather, and evolving end-use need for electricity. NERC and industry stakeholders have recognized key resource adequacy program attributes that may become needed to address specific challenges faced by system planners and operators. **Table 15** includes five of these attributes and a brief description of how the attribute can be implemented. Assuring an adequate supply of electricity requires modernizing planning approaches. NERC encourages each assessment area to evaluate the program attributes needed to plan effectively for current and future challenges and implement those identified as essential.

Table 15: Resource Adequacy Program Attributes

Attributes	Objective	Implementation
1. Uses Energy Risk Criteria	To ensure energy adequacy in systems with VER and fuel limitations, resource planners and markets need to augment existing 1-day-in-10 load-loss criteria with additional energy risk metrics.	Establish criteria based on EUE or similar energy risk metric(s).
2. Evaluates Resource Contributions at Risk Periods	As periods of shortfall risk on the system change with changing resource and demand characteristics (e.g., risks during winter and summer, peak net demand, and shoulder seasons), methods for assigning resource contributions in resource procurement and assessments must evolve.	Adopt effective load-carrying capability or other probabilistic methods for determining resource contributions during risk periods.
3. Load Forecasting Accounts for Growth Uncertainty	Future electricity demand is being influenced by the pace of electrification, industrialization, data center development, and DER adoption. Load forecasts for adequacy assessment and resource planning need to account for new growth patterns and uncertainty.	Capture the forecast drivers needed for the area and address uncertainties.
4. Considers Effect of Extreme Scenarios on Adequacy	To reduce the unique resource adequacy risks from wide-area extreme weather events, resource adequacy programs should evaluate potential system impacts and weather scenarios to mitigate risk to the BPS.	Analysis considers low-probability energy events (e.g., drought, multi-day weather patterns) and adequacy criteria include load-loss event magnitude and duration.
5. Includes Coordinated Interregional Transfer Capability	Interregional transfer capability can provide enhanced reliability and resilience and is most effective when resource adequacy programs include coordination with neighbors.	Model transfer limits and deliverability; implement processes for seams coordination.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. See **Figure 8** for seasonal peak demand growth over the current and prior assessment periods and **Figure 9** for net energy growth. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter demand growth continues to outpace summer demand growth: The 10-year aggregated winter peak demand is forecast to rise by over 245 GW, a 65% increase from last year's 149 GW growth projection. Compound annual growth rates (CAGR) for summer and winter peak demand are the highest since NERC's tracking started in 1995. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 10.**

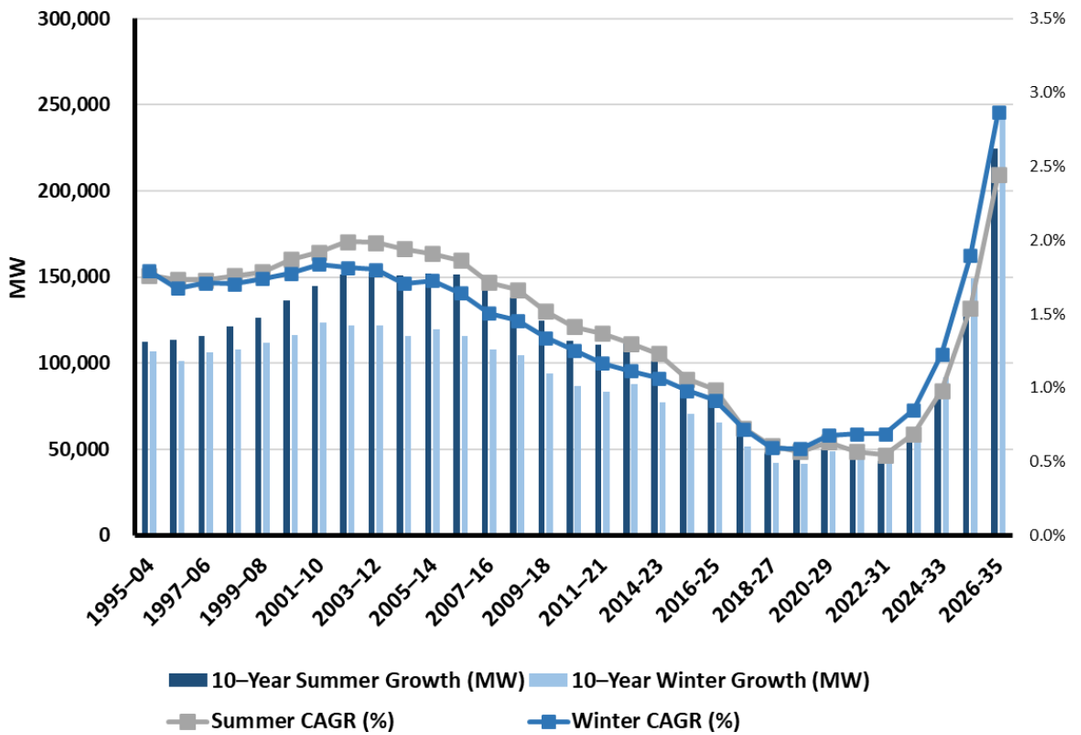


Figure 8: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

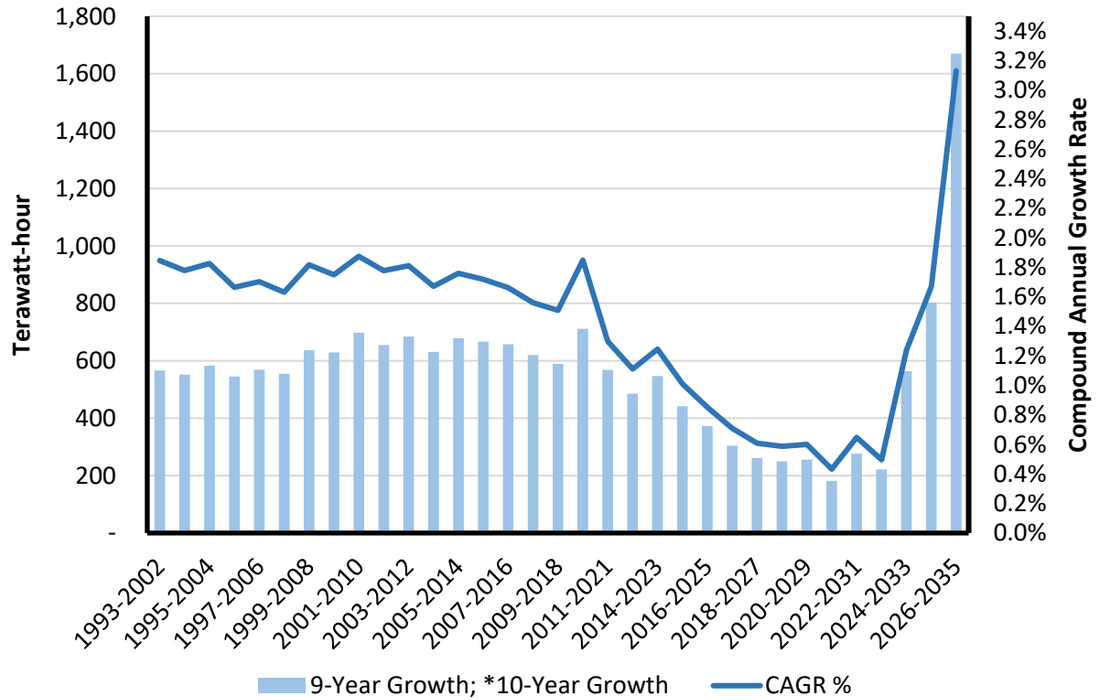


Figure 9: Net Energy for Load Growth and Rate Projections

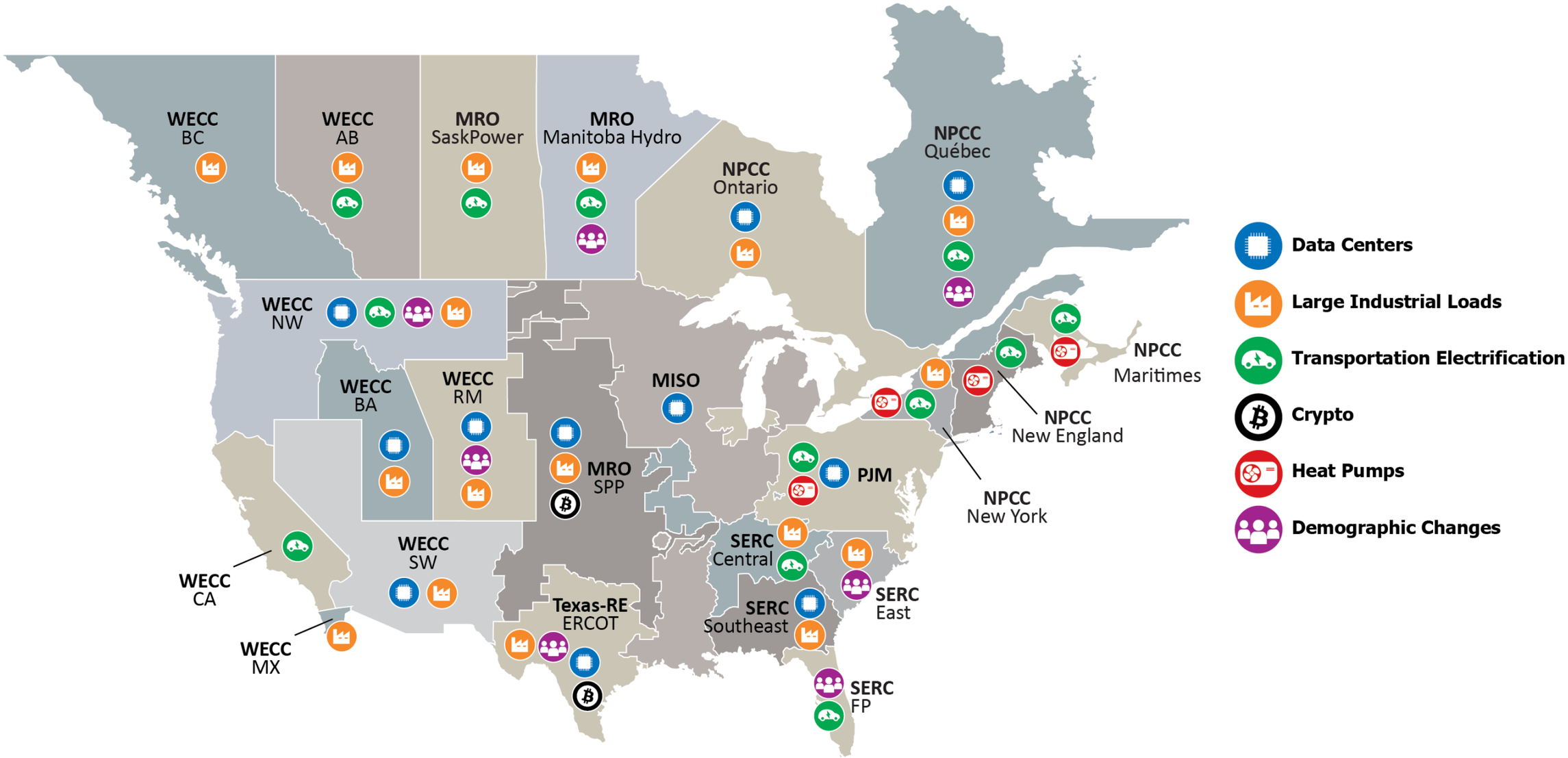


Figure 10: Primary Demand Drivers by Assessment Area

Data Centers and Large Commercial and Industrial Loads

New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years. These and other large commercial and industrial loads are connecting rapidly to the BPS. The emerging large loads present unique challenges to forecasting and planning for increased demand.

Load forecasts collected by NERC for the *2025 LTRA* reveal the massive build-out of data centers in many parts of North America. Texas, PJM, and the WECC assessment areas are reporting steep demand increases due primarily to new data centers and large loads. BAs within WECC reported that planned data centers account for an average of 10% of demand, with some BAs reporting as high as 40% of the demand forecast. See **Figure 11** and **Figure 12** for projections in ERCOT and most WECC assessment areas, respectively.

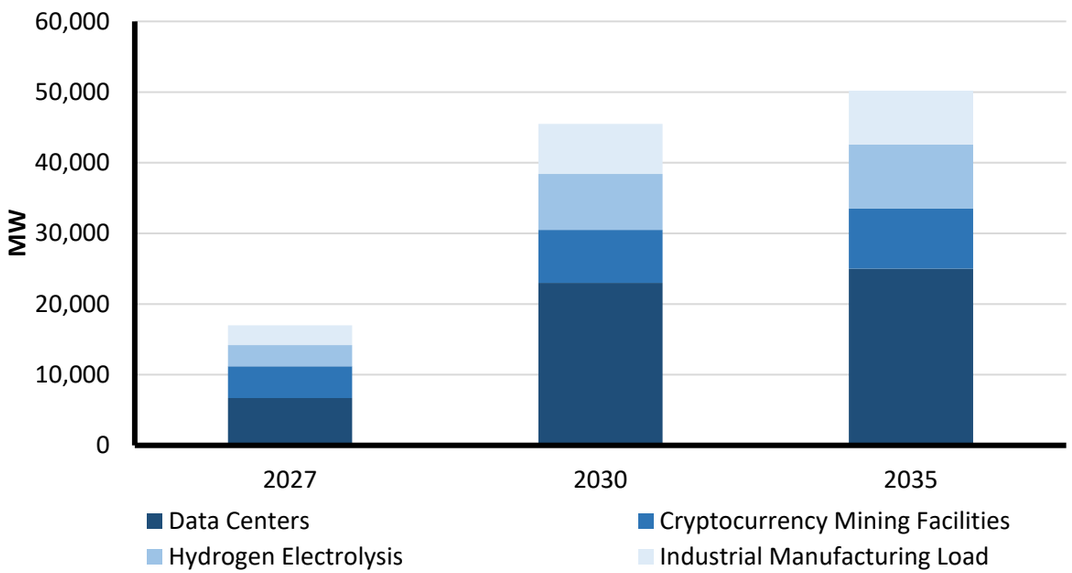


Figure 11: Large-Load Projection Breakdown in ERCOT

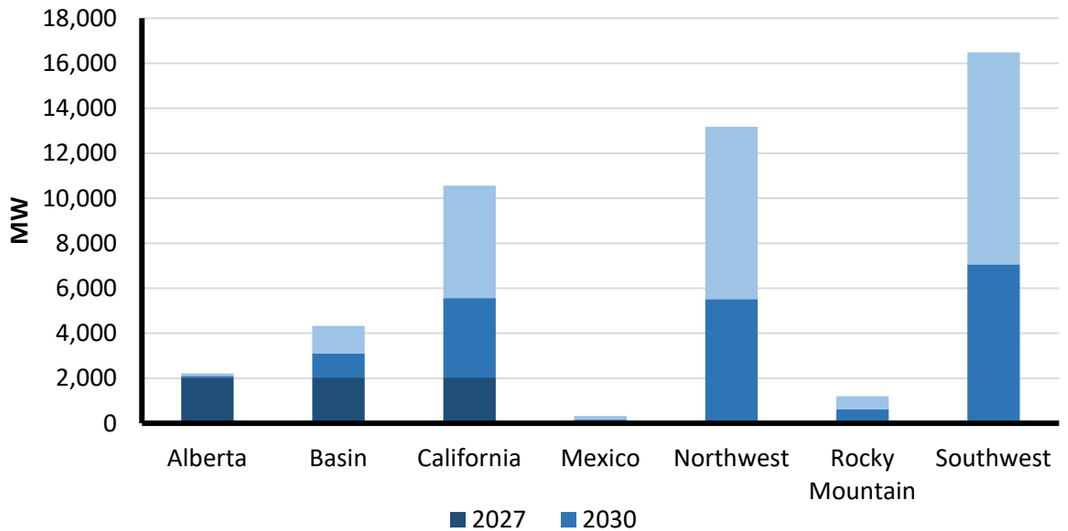


Figure 12: Large-Load Projection by Year in WECC Assessment Areas

Demand forecasts and large load projections throughout the LTRA are based on LSE and BPS system planner forecasts. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Consequently, data center and large load growth forecasts in the LTRA are likely to be more conservative than predictions from the technology industry or from economic, research, academic, and policy organizations.

In Texas, fluctuations in recent large-load interconnections activity continue to affect both near- and long-term demand expectations. Utilities and system operators are also gaining insights from large-load development and operating behaviors and applying them to future forecasts. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. New data center demand projections in Texas are reduced by almost 50% of their original requested load level to reflect the observed consumption behavior of existing data center sites during their initial operations. ERCOT also slashes most new large loads that have yet to enter a contract for transmission service from its long-term demand forecast and adjusts

expected in-service dates to account for historical delays. Similarly, PJM is refining processes for large load forecasting starting with its 2026 load forecast.[20]

There is already evidence that large loads impact BPS reliability. For example, the Eastern and ERCOT Interconnections have observed load-reduction events[21] with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction. The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation and caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying size reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue. NERC's RSTC established a Large Loads Task Force (LLTF)[22] to better understand the reliability implications of growth in large loads and develop solutions. The LLTF published the white paper *Characteristics and Risks of Emerging Large Loads*[23] in 2025, and another white paper, *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, is forthcoming.[24]

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2024 LTRA*, peak season CAGR has risen in all assessment areas except five: MRO-Manitoba Hydro's winter CAGR fell from 1.79% to 1.37%, MRO-SaskPower's winter CAGR fell from 1.32% to 0.89%, NPCC-New England's summer CAGR from 1.28% to 1.05%, NPCC-New York's summer CAGR from 0.87% to 0.84%, and SERC-East's summer CAGR fell from 1.88% to 1.17%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from summer-peaking systems to winter-peaking (or dual-season peaking) systems and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (late-2030s)
- NPCC-Ontario (2030; dual-season peaking)
- Texas RE-ERCOT (2035)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer. In Canada, WECC-Alberta has been operating as a dual-peaking system.

Demand Response

Demand-side management programs are growing for many assessments areas. DR is one form of demand-side management. It consists of mainly commercial and industrial end users that have entered into agreements with load-serving entities to curtail demand when needed by grid operators. DR can assist with reducing load during critical periods of increased demand, such as heat waves or winter storms. **Figure 13**, **Figure 14**, and **Figure 15** show the increasing projections for DR in the first year of the forecast for the past five LTRA reports in Texas RE-ERCOT, NPCC-Québec, and NPCC-New York, respectively. Other forms of demand-side management include EE and conservation programs administered by utilities. The reported contributions from DR, EE, and conservation programs reduce total electricity demand in load forecasts and provide reliability benefits that are accounted in LTRA reserve margin calculations and the ProbAs.

[20] Planned revisions to PJM's treatment of large load forecasts from PJM's Load Analysis Subcommittee: 20250613-item-03--large-load-adjustment-process-improvement-discussion.pdf

[21] "Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions," NERC, Jan. 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf

[22] NERC Large Loads Task Force webpage: Large Loads Task Force (LLTF)

[23] The LLTF's *Characteristics and Risks of Emerging Large Loads* White Paper

[24] The LLTF's action plan is updated regularly and contains links to white papers, guidance, and presentations.

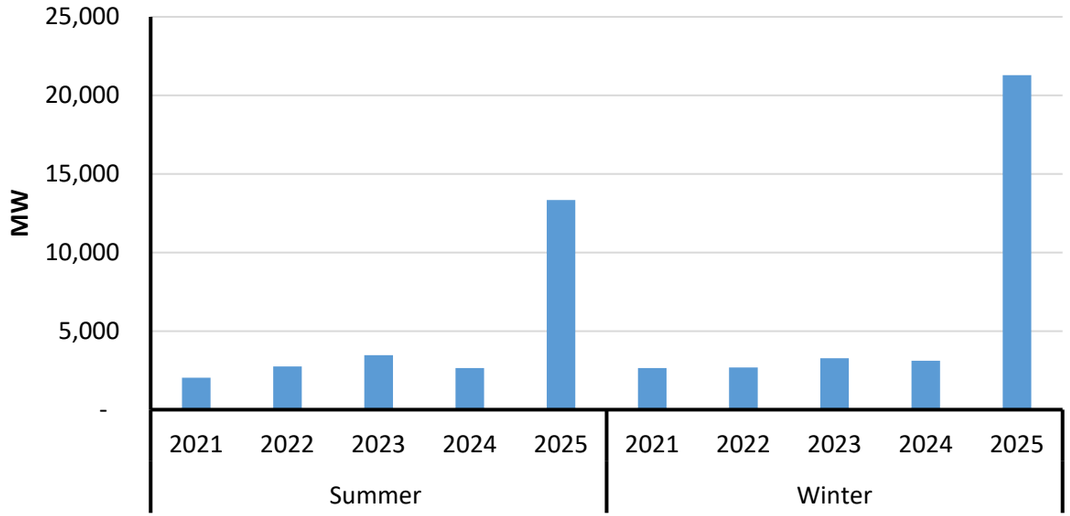


Figure 13: Texas RE-ERCOT Demand-Response Trend in Past Five LTRAs (Year 1)

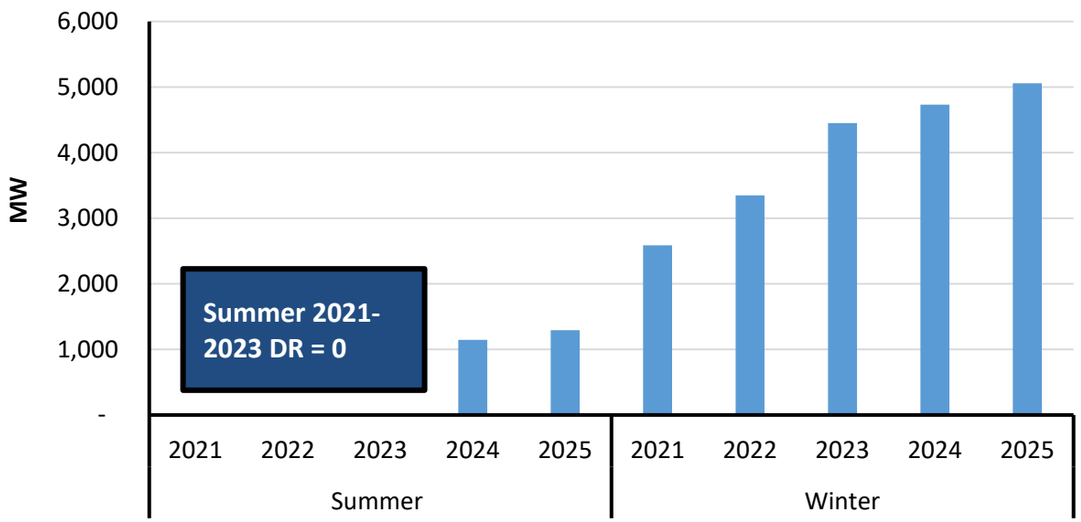


Figure 14: NPCC-Québec Demand-Response Trend in Past Five LTRAs (Year 1)

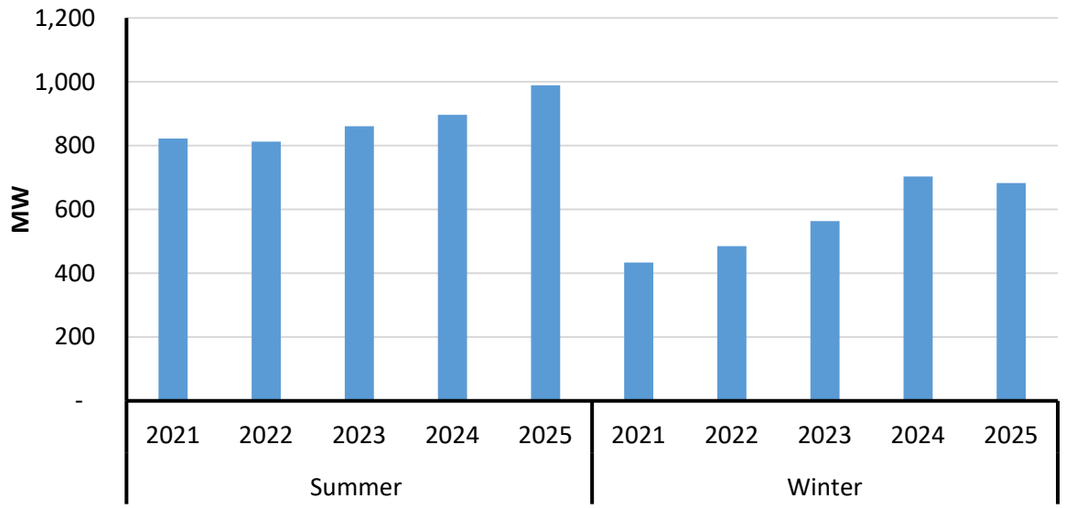


Figure 15: NPCC-New York Demand-Response Trend in Past Five LTRAs (Year 1)

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and DER performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year noticeably affected resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Resource Mix Changes

On-peak resource capacity increased approximately 6.2 GW across the interconnected North American BPS over the last year. This is down from approximately 8.3 GW of net on-peak capacity additions reported a year ago in the *2024 LTRA*. Net capacity from fossil-fueled generators continued to decline at a rapid pace over the last year with approximately 21 GW leaving the system. Continent-wide, net BPS additions of battery, wind, and solar resources totaled 23 GW over the last year (see Table 16).

Table 16: Existing BPS Resource On-Peak Capacity

Resource Type	2024 Capacity (MW)	2025 Capacity (MW)	Difference (MW)
Coal	180,402	166,799	– 13,603
Petroleum	30,987	27,931	– 3,056
Natural Gas	484,148	479,901	– 4,247
Biomass	7,381	7,181	– 200
Solar	66,293	70,723	+ 4,430
Wind	31,370	35,121	+ 3,751
Geothermal	3,881	2,932	– 949
Conventional Hydro	105,792	111,117	+ 5,325
Run-of-River Hydro	2,047	2,017	– 30
Pumped Storage	19,422	19,734	+ 312
Nuclear	105,384	105,389	+ 5
Hybrid	1,322	1,102	– 220
Other	774	830	+ 56
Battery	8,587	23,267	+ 14,680
Total	1,047,790	1,068,514	+ 6,254

Like last year, the anticipated BPS generating capacity (i.e., capacity from existing generation + expected additions – expected generator retirements) fell short of industry projections reported in the LTRA, furthering the concerns that accelerating peak demand growth is continuing to outpace the supply resources.

Figure 16 compares this year's existing and Tier 1 nameplate and on-peak capacity against the actual current capacities derived from data collected for this year's LTRA. Bars that cross the 100% line represent resources with actual additions exceeding projections from 2024, and bars that fall to the left of the 100% line represent resource types with actual additions less than projected in 2024.

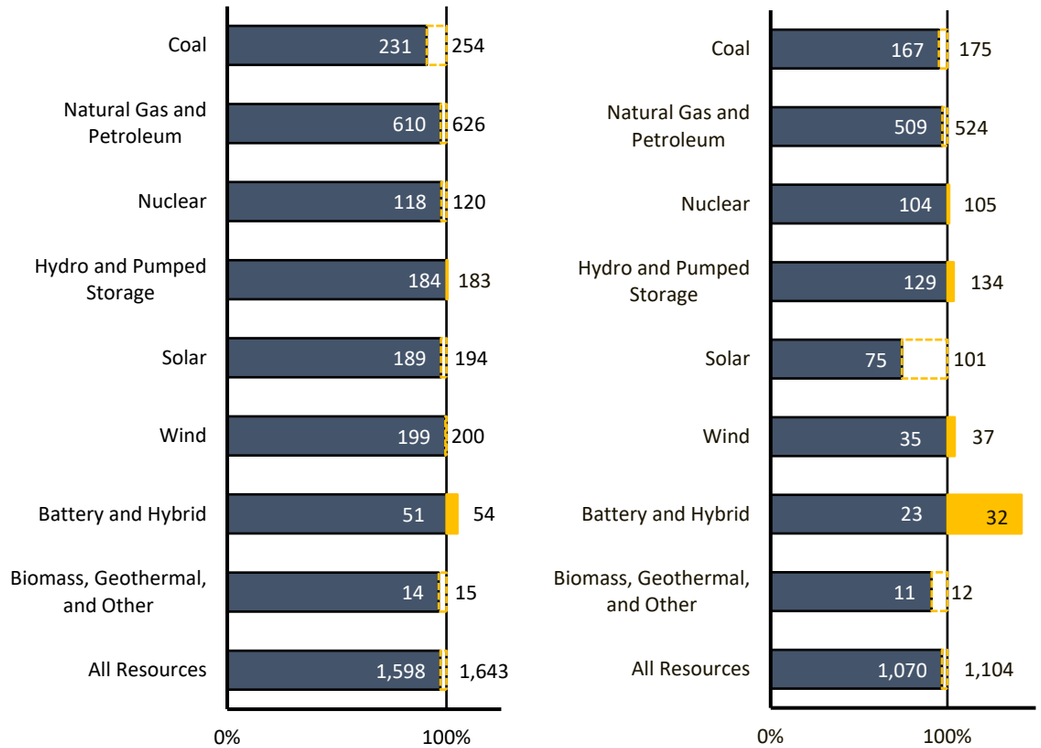


Figure 16: Comparison of North America's 2025 Existing and Tier 1 Nameplate (Left) and On-Peak (Right) Capacities in GW to *2024 LTRA* Projections

Continuing the trend from last year, battery energy storage systems were added to the system faster than expected, while coal, natural gas and petroleum, and solar resources were once again over-projected. As coal capacity continued its decline because of plant retirements and age-related derating, its over-projection from last year means that it left the system faster than anticipated in 2025.

Notably, the capacity contribution of VERs, including solar, wind, battery, and some types of hydroelectric generation, to serving load at peak demand differs from the nameplate, or installed capacity. The right plot in Figure 16 above includes a complementary view to the on-peak projections using nameplate capacity to accommodate different capacity accounting methods. Both 2025 on-peak and nameplate solar was over-projected across the North American BPS last year. These over-

projections continue to support electric industry reports of construction delays and project withdrawals prior to commercial operations that prevented the expected interconnection of new resources.

Planned On-Peak Capacity Additions

New resources are added to the BPS through each area's interconnection planning process. Entities have expressed concerns that the pace of resource additions has been too slow to meet demand growth and future retirements in the existing generator fleet. **Figure 16** above highlights that industry participants are expecting peak demand growth of nearly 250 GW over the next 10 years because of accelerating demand for a variety of electricity users. Planning for such explosive growth and the uncertainty about its magnitude and timing is a complicated challenge for system planners.

Figure 17 illustrates the planned on-peak capacity additions and subtractions across the North American BPS over the next 10 years. Additions are illustrated by the positive portions of the stacked columns and include both Tier 1 and Tier 2 additions. In general, Tier 1 resources are in the final stages for connection, while Tier 2 resources are further from completion (see **Demand Assumptions and Resource Categories**). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. Deratings and retirements of the existing fleet are stacked in the negative Y direction with diagonal hatching patterns.

To keep up with forecasted demand growth and generator retirements, planned resources with interconnection agreements will need to come in on time, and additional resources in development must mature through the interconnection process quickly (see **Figure 18**). The on-peak capacity of approved resource additions found in integrated resource plans (IRP) and ISO/RTO expansion plans through 2028 is able to keep pace with the aggregated peak demand forecasts of all NERC assessment areas. Beyond 2028, new approvals for resource additions are required to maintain robust growth. Furthermore, additional generation is needed to make up for capacity lost to generator retirements. Considering the generator retirements depicted in **Figure 17**, there are only approximately 60 GW of net additions planned in the most certain Tier 1 category over the next 10 years. Another 190 GW of Tier 2 or other resources (70% of Tier 2's 10-year total) would need to complete the interconnection planning process and reach commercial operations to meet the expected demand growth, illustrating the pressure on resource and system planning to rapidly add resources. DR programs, EE improvements, and transmission development to enable interregional transfers that take advantage of geographic diversity can also support growing demand.

To respond to this urgent need for new resources, independent system operators and regional transmission organizations have been developing new market structures and products to retain capacity and expedite interconnection of new generation and storage. Three such programs established by ISO/RTOs are PJM's Reliability Resource Initiative, MISO's ERAS process, and SPP's *Expedited Resource Adequacy Study*.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year's 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown only modestly since the 2024 LTRA by 7 GW (1.7%) as compared to a year-over-year growth of 44 GW last year.

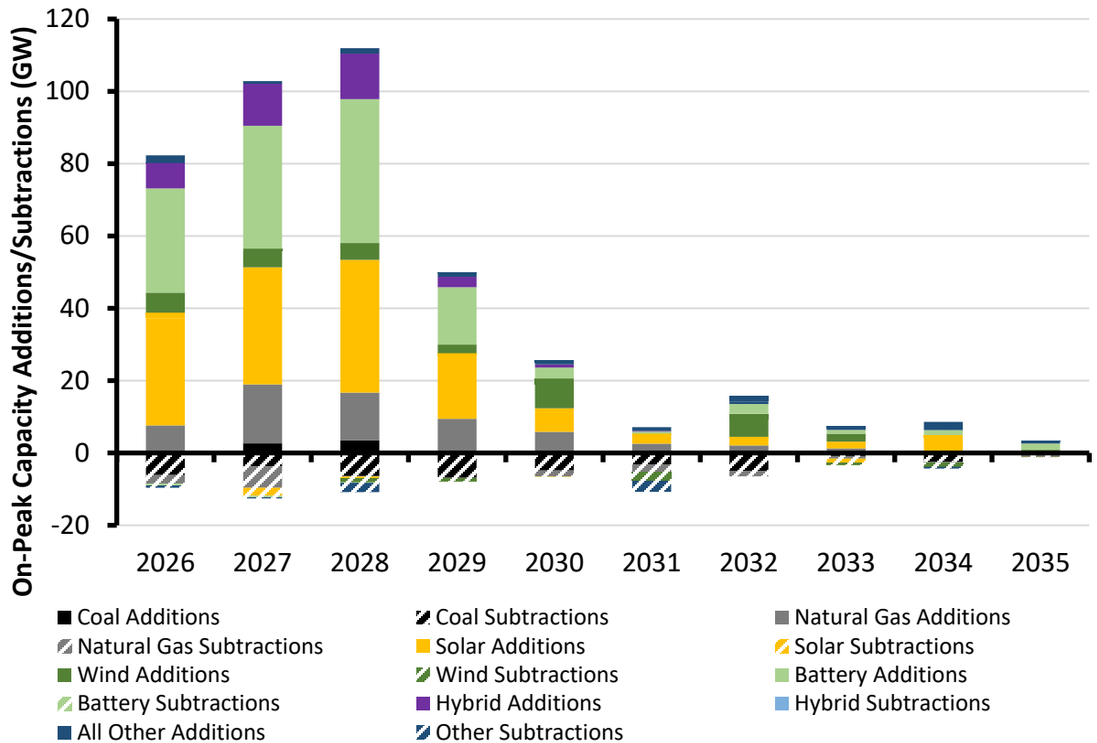


Figure 17: Projected Annual On-Peak Capacity Additions and Subtractions by Resource Type and Net Cumulative Capacity Changes

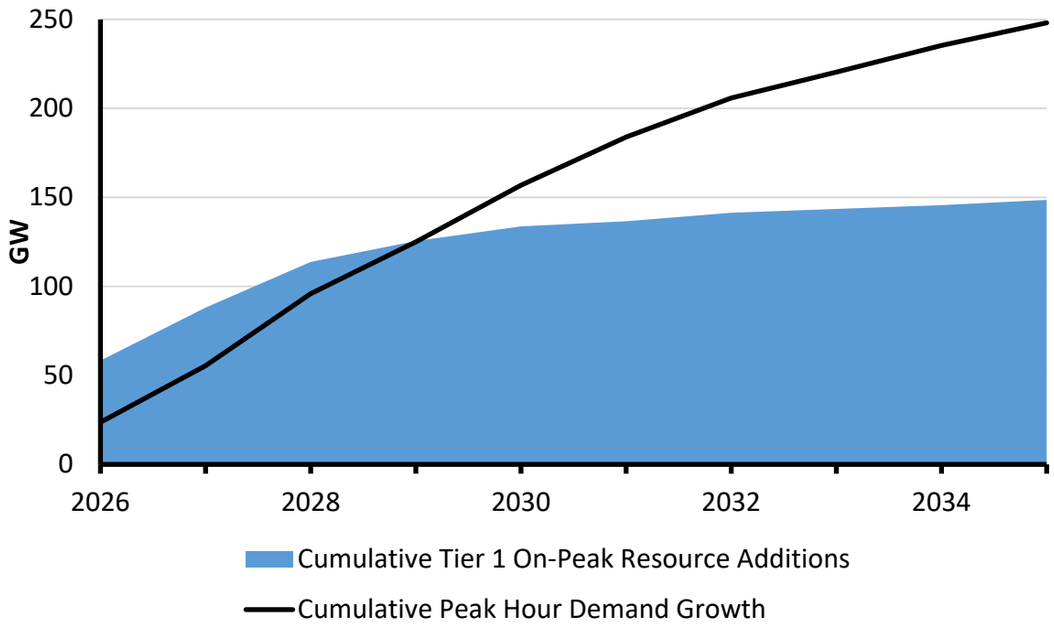


Figure 18: Expected BPS Resource Additions (Tier 1) and Aggregated BPS Peak Demand Growth Through 2035

Increasing On-Peak Share of Variable Resources

Year-over-year increases in the fraction of on-peak capacity provided by VERs—run-of-river hydro, solar, and wind—have continued since the 2024 LTRA with VER on-peak contributions increasing from 9.5% to 10.2%. This observed trend is projected to continue through 2035 with shares of on-peak VER capacity projected to rise to between 15% and 20% depending on the completion and interconnection of Tier 1 and Tier 2 resources. **Figure 19** shows existing on-peak capacity by resource type for 2024 and 2025 along with projected on-peak capacity by resource type for 2035 with Tier 1 and Tier 2 additions. Resource types with on-peak shares less than 5% are not labeled with their contribution fraction but are stacked in the graphic.

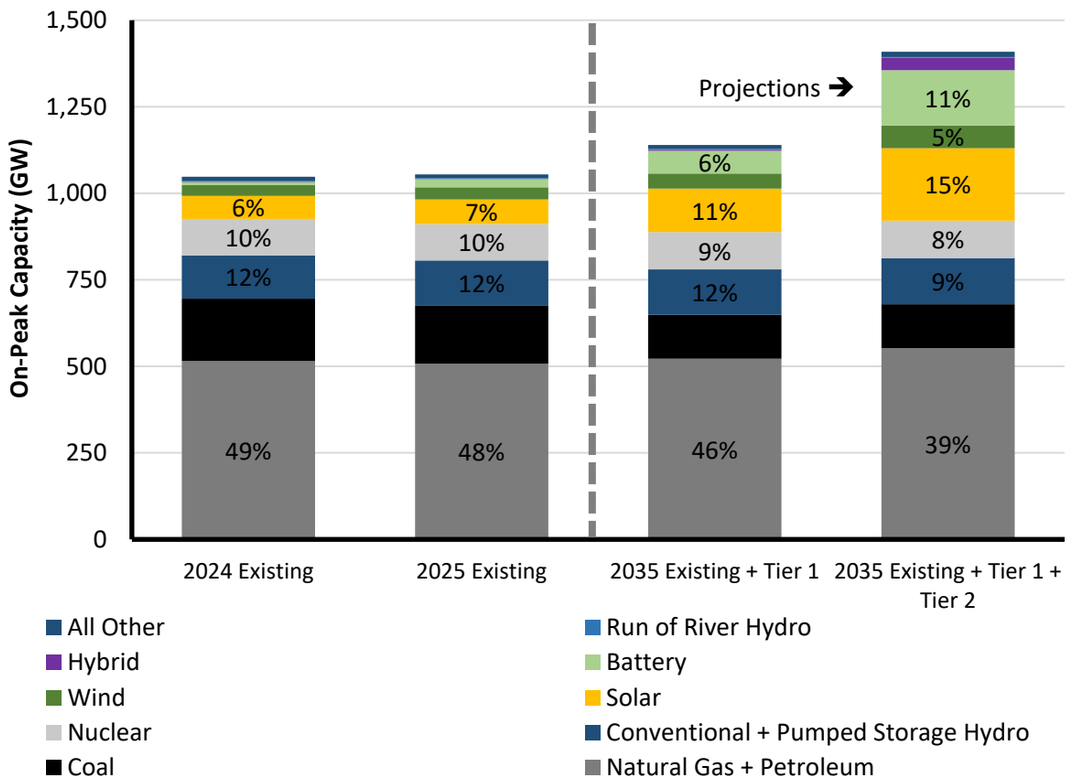


Figure 19: North America On-Peak Capacity Shares by Resource Type

Like last year, a relatively small change in total on-peak capacity was observed, but the continued trend of increasing VER share highlights that important reliability attributes continue to leave the system. Non-variable generation—including coal, petroleum, natural gas, biomass, geothermal, conventional hydro, and nuclear—as well as hybrid or storage systems can ramp up or down in response to demand. Non-variable resources can also provide other ERSs like system inertia, dynamic reactive support, and frequency response for stable grid operation. Many of the variable resources that are being added to the grid to replace non-variable resources cannot provide the same ERSs in their current configuration. This deficiency is amplified in the winter when on-peak contributions from variable resources are diminished by changing weather and environmental conditions.

System Frequency Response Analysis

Despite lower inertia from retiring synchronous generators and greater penetration of inverter-based resources, all four Interconnections expect adequate, diverse frequency response capabilities and a low risk of under-frequency load shedding (UFLS) activation. In preparing the *2025 LTRA*, NERC worked with the Regional Entities and system planners to assess the frequency response capability of the projected resource mix through 2027 on an Interconnection basis. The findings are summarized in Table 17.

Table 17: Measures of Frequency Response

Measure	What it Measures	Summary Assessment Findings
Synchronous Inertial Response (Measure 1)	The minimum inertial response amount (total stored kinetic energy) projected in each Interconnection	Despite the retirement of synchronous generation over the past eight years, there appears to be more than sufficient inertia within all Interconnections. ERCOT's use of load response to respond to frequency disruptions is effective in supporting low-inertia conditions.
Rate of Change of Frequency (Measure 2)	The calculated rate of frequency decline within the first 0.5 seconds following the largest credible contingency	No negative trends identified. Texas RE-ERCOT studies show that load response is extremely effective in arresting frequency due to its ability to perform very quickly.
Frequency Response Performance (Measure 4)	Simulated dynamic behavior of an Interconnection's response to the largest credible contingency	Simulations in both the Eastern and Western Interconnection show sufficient frequency response in future planning cases.

The results of analysis for each Interconnection are in Table 18. Non-synchronous resources have increased in all Interconnections since the last LTRA frequency response analysis in 2022. Each interconnection continues to project sufficient frequency response ERSs in the near term and have low likelihood of UFLS activation during a disturbance. These results were determined by dynamic studies performed for the Eastern, Western, and Québec Interconnections and analysis of operational procedures for the Texas Interconnection.

Table 18: Summary of the Results of NERC Frequency Response Sufficiency Assessment

Interconnection	Highest Non-Synchronous Penetration at Minimum Inertia Studied	Number of Critical Inertia Conditions Reached?	Lowest Frequency Nadir Observed in Planning Studies	Likelihood of Credible Disturbance Resulting in UFLS Activation
Eastern Interconnection	17.9%[25]	0	59.93 Hz	Low
Western Interconnection	42.9%[26]	0	59.65 Hz	Low
Texas Interconnection	65.7%	0	N/A	Low[27]
Québec Interconnection	37%	0	N/A	Low

Increasing Natural Gas Reliance

In 2024, natural-gas-fired power plants generated approximately 43.4% of all electricity generated in the United States, according to the U.S. Energy Information Administration, up from 43.2% in 2023. As of August 2025, natural-gas-fired power plants in the United States are on track to generate a slightly smaller share of electricity this year in comparison to last year, but accelerating energy demand through the remainder of the year and projected increases in net energy for load over the next 10 years indicate that natural-gas-fired generators will remain critical resources for BPS reliability in many areas.

Natural-gas-fired generators are especially important during the winter. Winter peak electricity demand in most areas occurs during early morning hours when unavailability of weather-dependent resources leads to a surge in natural-gas-fired generation's share of the resource mix. Severe winter weather events in 2021 and 2022 provide stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure fuel supplies during times of extreme electricity demand.

[25] EIPC Frequency Response Report

[26] 42.9% is the penetration of utility-scale non-synchronous generation. The Western Interconnection has a significant amount of DERs that are also non-synchronous. When DERs are included, the non-synchronous penetration was 54.9%.

[27] ERCOT procures responsive reserve service to protect from involuntary under frequency load shed after loss of two largest generating units at a single plant (2,805 MW). In March 2020, a new subproduct of responsive reserve service was introduced, FFR, which is triggered at 59.85 Hz within 0.25 seconds. Up to 450 MW of FFR can be procured as a part of responsive reserve service. This product is still going through implementation stages due to required changes to ERCOT systems.

Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to slightly more than 12 GW of new natural-gas-fired winter capacity if only the most certain Tier 1 resources come on-line. That number jumps to 41 GW of new natural-gas-fired winter capacity if both Tier 1 and Tier 2 resources come on-line (see **Figure 20**). Importantly, the vast majority of natural-gas-fired Tier 1 and Tier 2 additions—11 to 39 GW—are projected to come on-line in the next five years.

The timing and magnitude of natural-gas-fired generator additions remains uncertain in today's energy system planning environment. Multiple areas are conducting expedited resource assessments and interconnection process reforms with goals of adding more generator capacity to the grid over the next few years to meet rapidly accelerating electricity demands, particularly due to large-load addition. The early project submissions and selections from these programs indicate that actual natural-gas-fired additions may exceed previous industry projections in some areas. For instance, PJM Interconnection's Reliability Resource Initiative has led to the selection of approximately 8 GW of natural-gas-fired generator uprates and additions out of the nearly 17 GW of natural-gas-fired projects submitted for consideration. Round one selections for MISO's ERAS include approximately 4 GW of natural-gas-fired additions out of the 20 GW submitted to date, and SPP's *Expedited Resource Adequacy Study* includes approximately 9 GW of natural-gas-fired winter capacity additions in its interconnection queue. Most of these expedited additions that have been selected across all three programs have applied to come on-line before 2030.

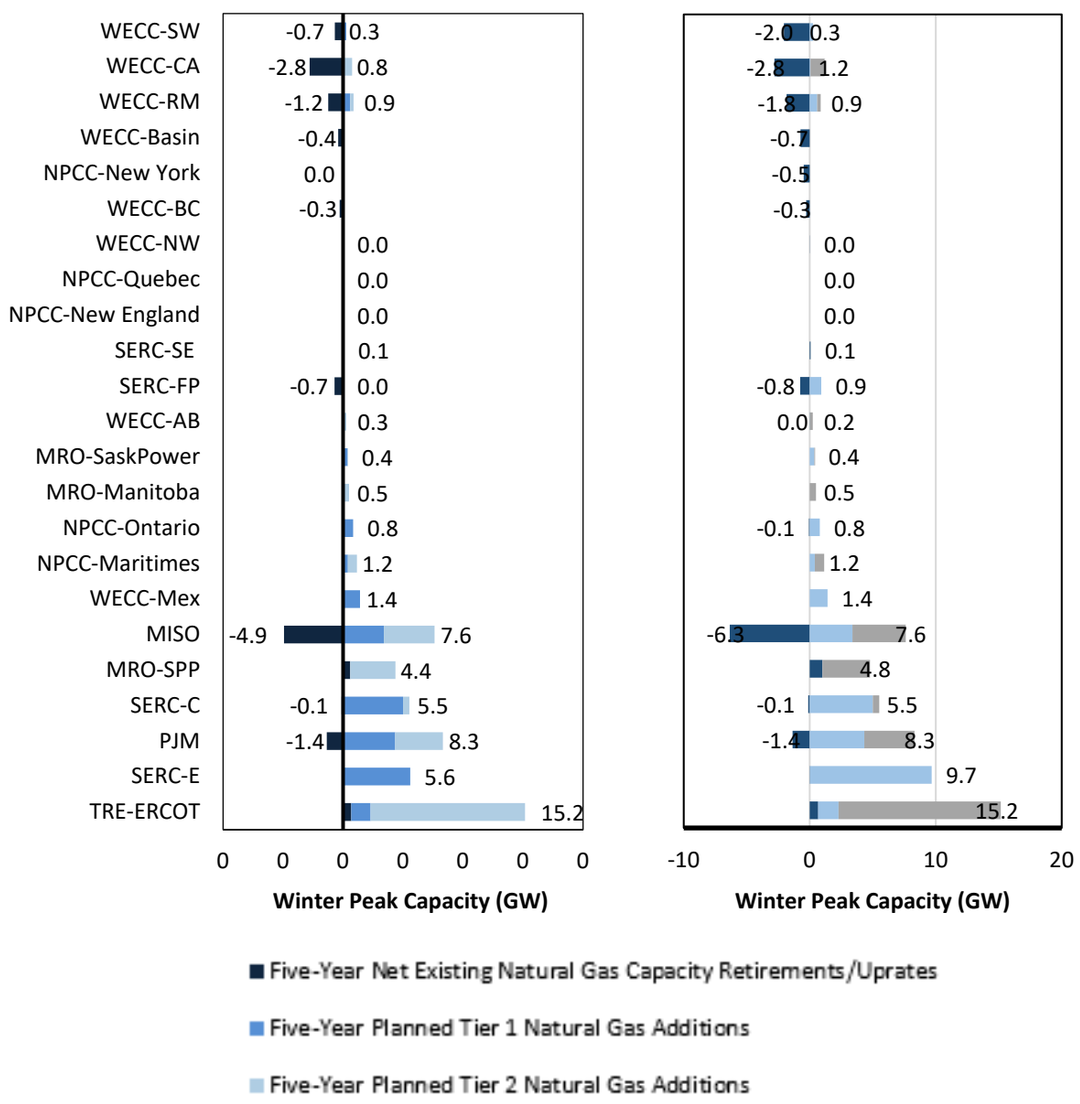


Figure 20: 5-Year (Left) and 10-Year (Right) Projected Natural-Gas-Fired Winter Capacity Additions by NERC Assessment Area

Natural Gas Infrastructure Development

Natural gas system planners have increasingly been coordinating with electric system planners to prepare for large additions to the natural-gas-fired power plant fleet. However, processes, regulations, and financial mechanisms that underpin capital investments and expansion of the natural gas pipeline and production system at times do not align with the variable operations of critical natural-gas-fired generators. For these reasons, among others, a significant percentage of natural-gas-fired power plants continue to rely on interruptible, or non-firm, supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas for both electricity generation and space heating can both dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability. When winter weather also impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can imperil even firm pipeline customers' supply as preparatory linepack is rapidly depleted.

There is a possibility that generators in the areas that are adding the most gas resources—MISO, MRO-SPP, PJM, SERC-C, SERC-E, and TRE-ERCOT—could secure additional firm fuel supplies from natural gas system projects planned or proposed over the next decade. **Figure 21** shows the amount of incremental natural gas pipeline capacity with in-service dates spanning the next five years. In total, S&P Global Energy projects that roughly 45 BCF/day of incremental natural gas pipeline capacity created by additional compression, expansions, pipeline repurposing, new pipelines, or reversal of flow directions will be built over the next decade. About one-third of this incremental capacity has gained regulatory approval and moved into the more formal stages of project development. Of the 15 BCF/day of regulatory approved gas pipeline capacity additions, only 5 BCF/day is planned to serve natural gas demand in the states outside of the Gulf Coast region.

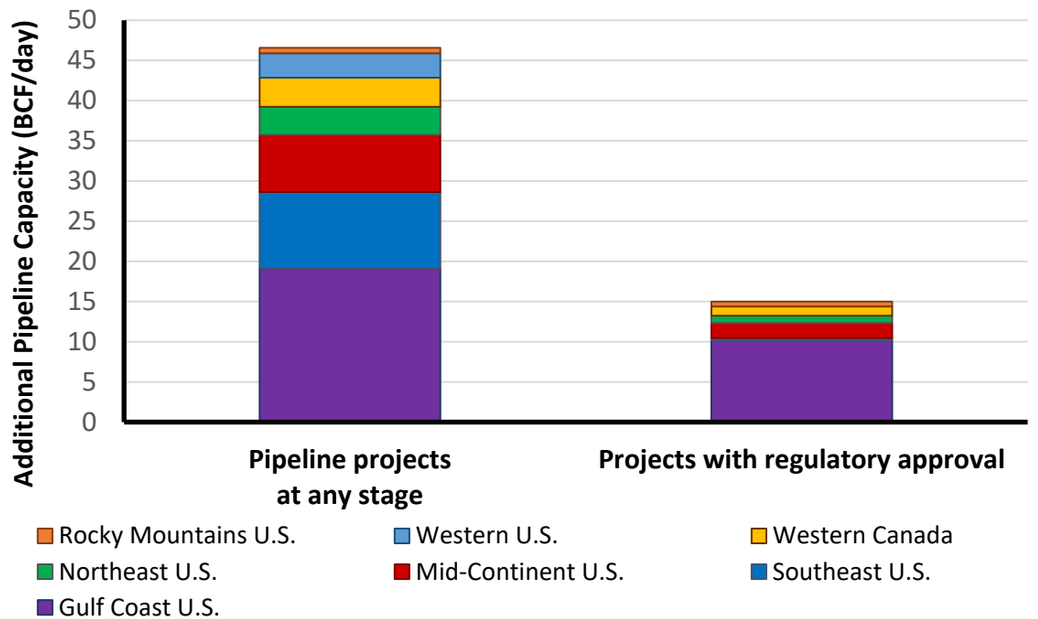


Figure 21: Projected Natural Gas Pipeline Capacity Expansion Projects by Project Stage (Source: S&P Global Energy)

The nearly 40 GW of natural-gas-fired winter capacity additions in the six areas adding the most gas resources could consume as much as 6–11 BCF/day of natural gas during a peak winter day after factoring plant type, efficiency, and whether the generator designated by its grid operator as a critical on-peak resource. While enough incremental pipeline additions to support this anticipated increase in gas demand seem to be moving through the natural gas project development process in those regions (see **Figure 22**), generators will need to compete with other pipeline customers for firm supply and delivery during periods of high gas demand. The magnitude of gas pipeline capacity additions suggests that there may be promising opportunities for generators to procure firm gas pipeline and supply contracts, but regulatory approval does not assure construction or commercial operation. In addition, if firm gas contracts cannot be secured for coincident high gas and electricity demand periods, like winter, ongoing critical generator projects might need to consider backup fuel capabilities so that they can assure fuel availability.

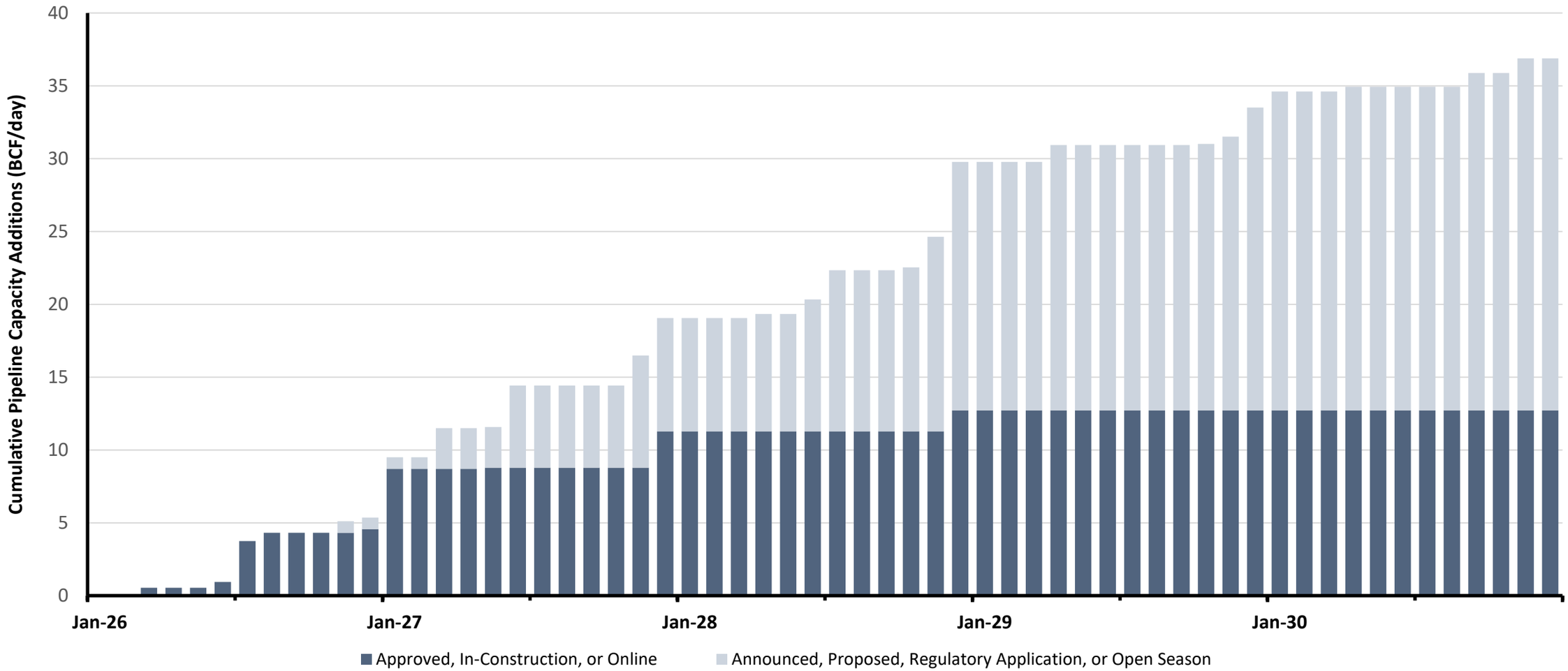


Figure 22: Projected Natural Gas Pipeline Capacity Expansion Projects Ending in MISO, PJM, SERC-C, SERC-E, SPP, and TRE-ERCOT Areas (Source: S&P Global Energy)

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years (see **Figure 23**) is substantially higher than the *2024 LTRA* 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

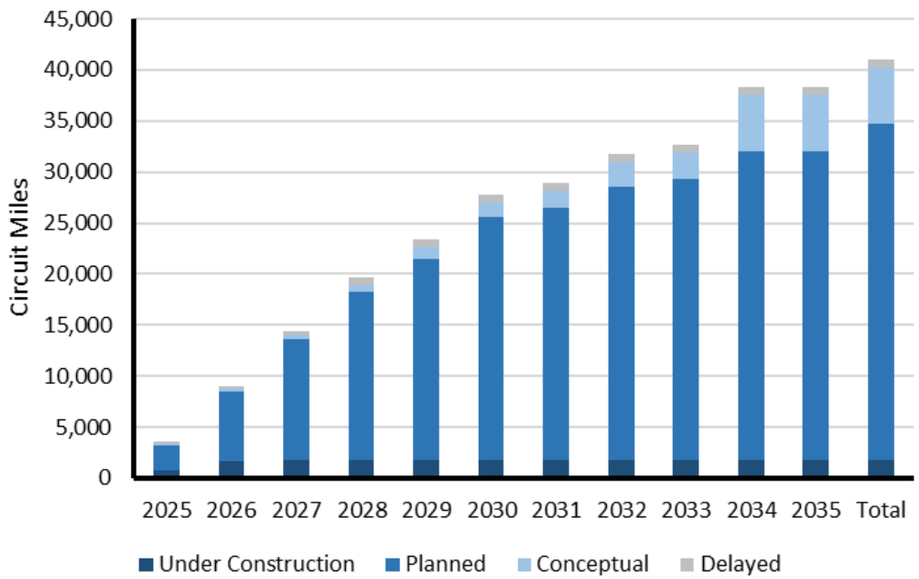


Figure 23: Future Transmission Circuit Miles >100 kV by Project Status[28]

Transmission flow patterns are changing and becoming more dynamic with resource shifts. New transmission projects are being driven by reliability, which includes efforts to replace aging infrastructure, integrate renewable generation, retire existing power plants, or meet increased demand forecasts. One such example is Hydro-Québec's plan to add significant new generating capacity by 2035, which necessitates several major EHV transmission projects. Similarly, several PCs have recently approved, or are actively contemplating, expansive EHV overlays on their systems to address a variety of needs, including ERCOT, SPP, MISO, PJM, British Columbia, and IESO. **Figure 24** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria.

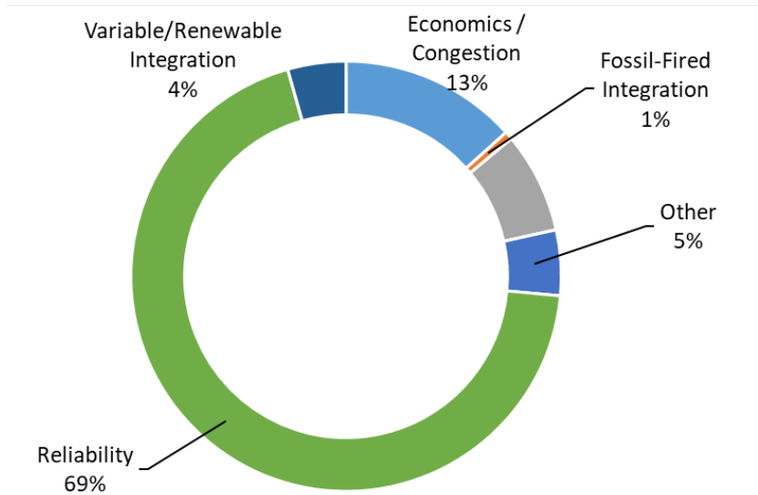


Figure 24: Future Transmission Circuit Miles by Primary Driver

There were 14,150 circuit miles (22,775 km) of reported transmission in development with an operating class greater than 400 kV (about 35% of the total miles in development). Nevertheless, intraregional transmission projects continue to greatly outnumber interregional transmission expansion. These interregional transmission projects can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,[29] including scenarios identified in the ITCS. Only 38 of the 863 transmission projects in development are for tie-lines and tie-line upgrades (down from 70 in last year's LTRA), which can support transfer capability between neighboring BA areas, including high-capacity dc interconnections, such as the 1,200 MW Appalaches-Maine (NECEC) and the 1,250 MW Hertel-New York (CHPE) projects. NYISO has identified a reliability risk if the CHPE project is not completed in a timely fashion. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

[28] The column at right is the total transmission projects reported to NERC and includes projects that did not specify an expected in-service date.

[29] *Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* | Federal Energy Regulatory Commission

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays as well as regulatory obstacles, such as siting and permitting. Other reasons for delays include economic impacts, planning and construction issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Interregional Transfer Capability Study (Canadian Analysis)

In the *2024 LTRA*, NERC provided a summary of the ITCS, a comprehensive study of existing and future interregional transfer capability undertaken by NERC in response to the Fiscal Responsibility Act of 2023. In addressing this legislation, NERC identified additions to transfer capability[30] for U.S. transmission planning regions (TPR) that could support energy adequacy.[31] NERC filed the completed study report with FERC on November 19, 2024.[32] Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces. The *ITCS Canadian Analysis* (Canadian Analysis) was published in April 2025.

The Canadian Analysis was the first-of-its-kind assessment of transfer capability and hourly energy margin analysis in Canada under a common set of assumptions but did not represent a transmission plan or blueprint. Transmission assessments, like the Canadian Analysis, are crucial to understanding potential options to mitigate future risks; however, alternative approaches other than transmission, such as local generation or demand-side solutions, can also mitigate future energy risks. The study results should be considered as an input into subsequent planning discussions that will consider broader objectives and the cost effectiveness of different alternatives to meet long-term needs.

Transfer Capability Analysis

The current transfer capability analysis between each pair of neighboring TPRs focused on 2024 Summer and 2024/25 Winter cases, with results shown in **Figure 25** and **Figure 26**, respectively. These transfer capabilities represent the ability of the entire network to move energy from one TPR to another TPR[33] but are not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities.

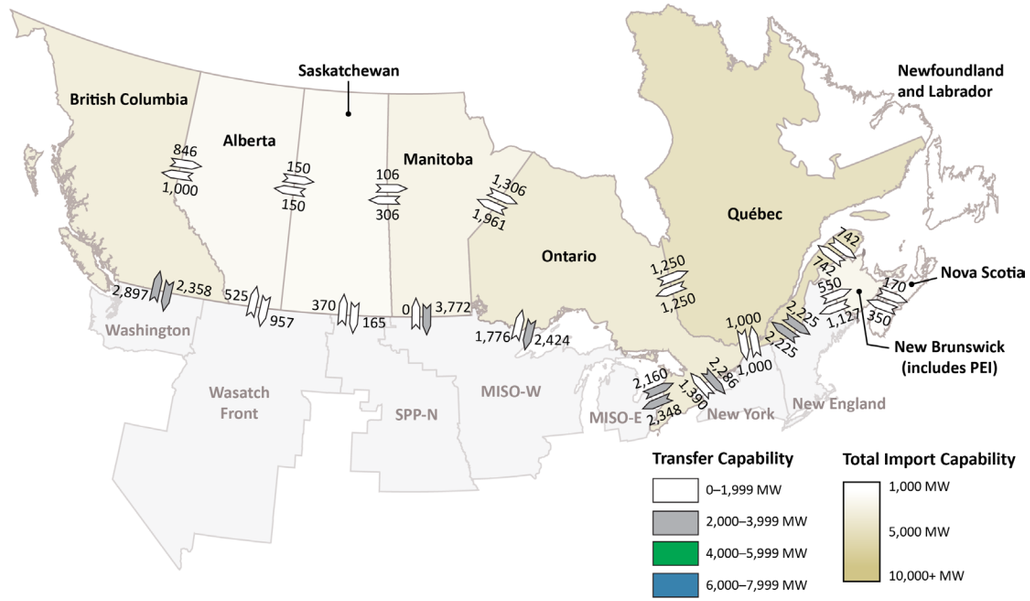


Figure 25: Transfer Capabilities (Summer)

[30] Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

[31] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.

[32] NERC filing of the *Interregional Transfer Capability Study*, FERC Docket AD25-4-000.

[33] Transfer capability is not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities. Since this study did not follow a path-based calculation method used by many TPRs, results generally do not match individual facility ratings.

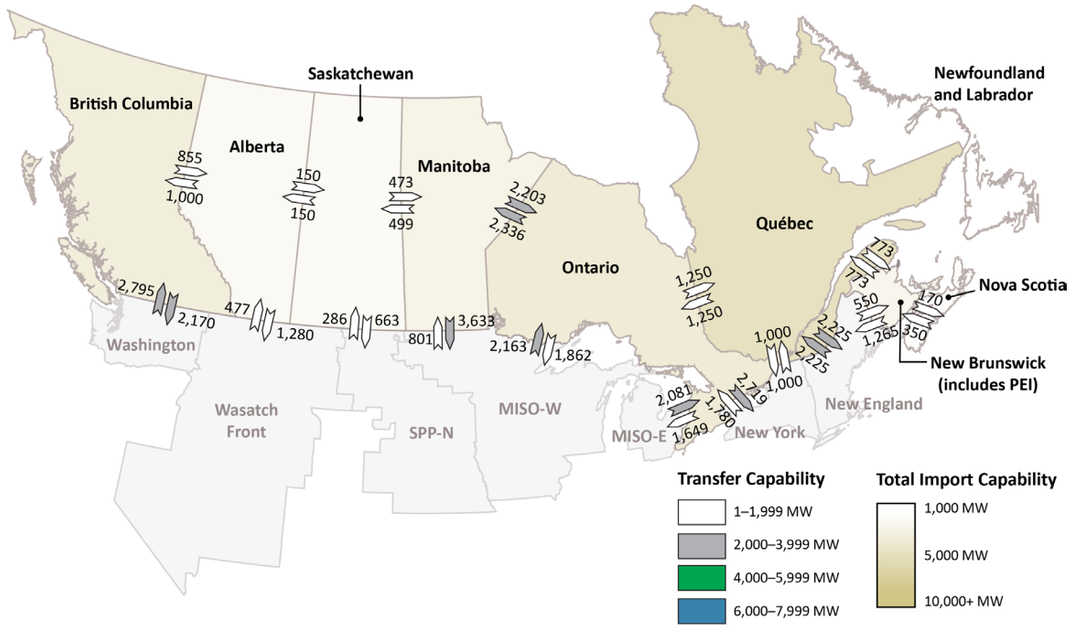


Figure 26: Transfer Capabilities (Winter)

The transfer capability results reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, which can vary significantly between seasons.

Key Findings–Transfer Analysis

- Transfer capability varies seasonally and under different system conditions that limit transmission loading; it cannot be represented by a single number.
- Transfer capability is highly dependent on coordinated phase angle regulator settings, particularly in Saskatchewan, Manitoba, and Ontario.
- Prince Edward Island load impacts the transfer capability from New Brunswick to Nova Scotia.
- Transfer capability differs across Canada, with total import capability varying between 5% and 80% of peak load.
- Observed transfer capabilities are generally higher between Canada and the United States but relatively lower between provinces.
- The magnitude of transfer capability is not itself a measure of energy adequacy.
- Interregional transfer capability, as studied in this analysis, is not synonymous with path ratings.

Transfer Capability Additions

The Canadian Analysis also evaluated the future energy adequacy of the BPS if historical extreme weather conditions occurred again.[34] Specifically, the study applied 12 past weather years to the 2033 load and resource mix projection reported in the *2023 LTRA* using the current transfer capabilities.[35] The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby helping to improve energy adequacy. While there are several factors that Transmission Planners consider (including reliability, economics, and policy objectives) given NERC's role, the Canadian Analysis focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

[34] This study did not incorporate climate change models.

[35] The transfer capability analysis calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Identified additions to transfer capability do not account for any changes to the transmission network that are planned after Winter 2024/25.

Key Findings–Energy Margin Analysis (2033)

- Canadian systems, like U.S. systems, were found to be increasingly vulnerable during extreme weather due to anticipated load increases and the changing resource mix. Transmission limitations, and potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional weather conditions. The import capability that could be beneficial during extreme conditions varied significantly across the country. An additional 12–14 GW of transfer capability may be an effective vehicle to strengthen energy adequacy under extreme conditions.
- More recent industry forecasts reflected in *2024 LTRA* data generally result in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts. Ongoing studies will capture future changes.
- Weather-related outages were not found to be a major contributor to deficiency events, as Canadian systems are generally designed to handle extreme cold conditions. However, high winter peak loads can still challenge the available energy supply.
- Some identified transmission additions could be addressed by projects already in the planning, permitting, or construction phases. Likewise, existing system capability to switch resources or load between provinces, which was not accounted for in this study, may help reduce the identified shortfalls.
- The importance of maintaining sufficient generating resources underpins the study's assumptions. Higher-than-expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability additions if surplus energy is available from neighbors.
- A broad set of solutions should be considered, including transmission, local resource, demand-side, and storage solutions. A diverse and flexible approach allows tailored solutions specific to each province's vulnerabilities, risk tolerance, economics, and policies.

Just as in the U.S. ITCS, the Canadian Analysis found potential for energy deficiency in all 12 weather years evaluated. The results identified the potential for energy deficiency in six provinces, with a maximum resource deficiency of 10 GW in Québec based on *2023 LTRA* data. A sensitivity study using more recent forecasts, based on *2024 LTRA* data, generally resulted in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts.

The Canadian Analysis used these results to develop a list of additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. The analysis identified 14 GW of additional transfer capability that would improve energy adequacy under the studied extreme conditions throughout Canada. In the U.S. analysis reported last year, 35 GW of additional transfer capability was recommended across the U.S. to improve energy adequacy under extreme conditions. Figure 27 shows the existing and potential new interfaces for Canadian TPRs where beneficial additional transfer capability is identified.

Transfer capability additions are based on 2033 resource mix and other study assumptions

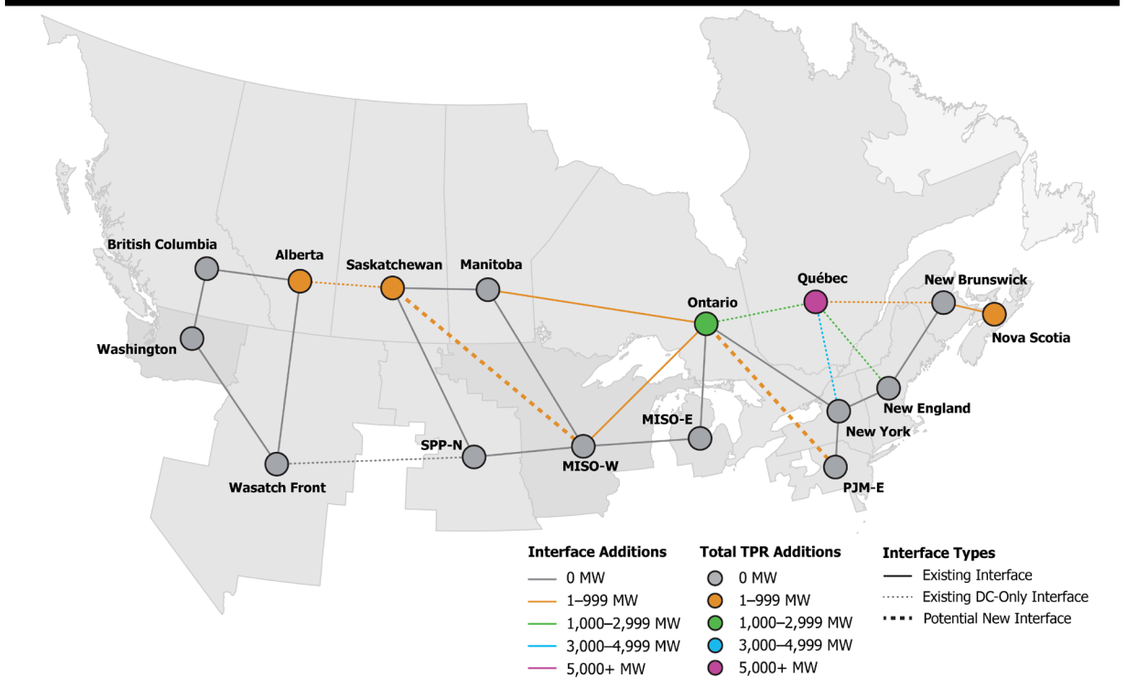
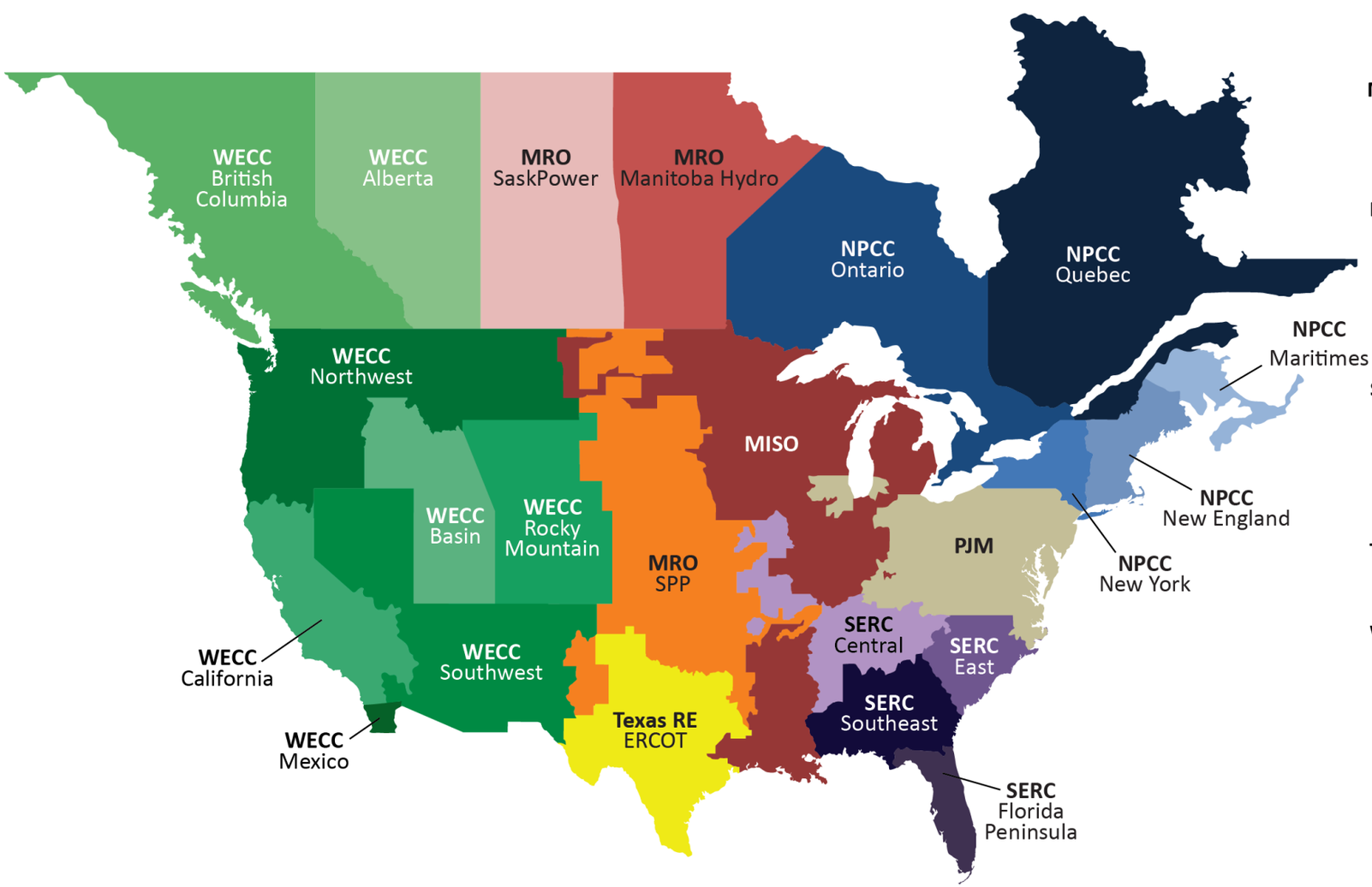


Figure 27: Transfer Capability Additions

Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



- MISO *(Midcontinent Independent System Operator)*
- PJM

MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- MRO-SPP *(Southwest Power Pool)*

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Florida Peninsula
- SERC-Southeast

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

WECC – Western Electricity Coordinating Council
- WECC-Alberta
- WECC-Basin
- WECC-British Columbia
- WECC-California
- WECC-Mexico
- WECC-Northwest
- WECC-Rocky Mountain
- WECC-Southwest

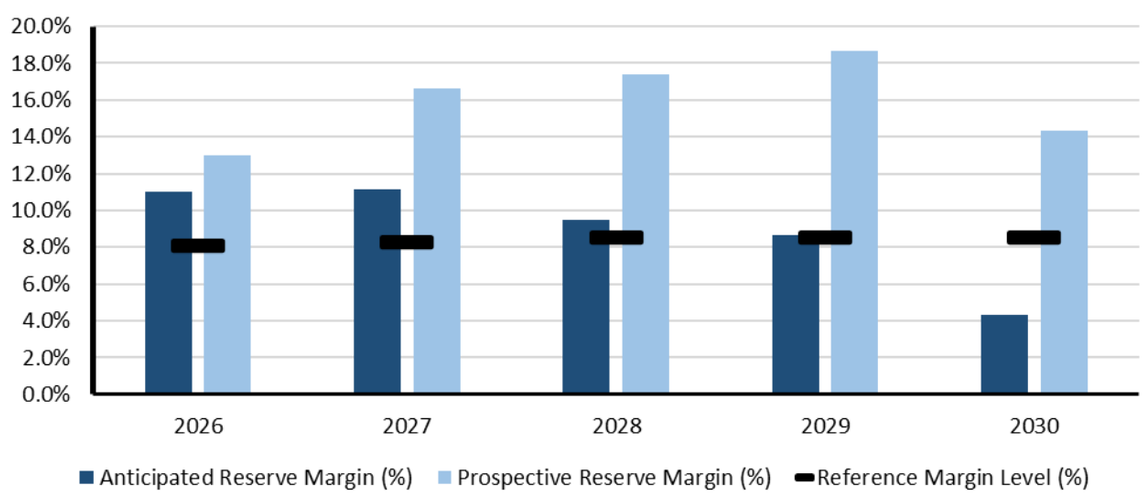


MISO

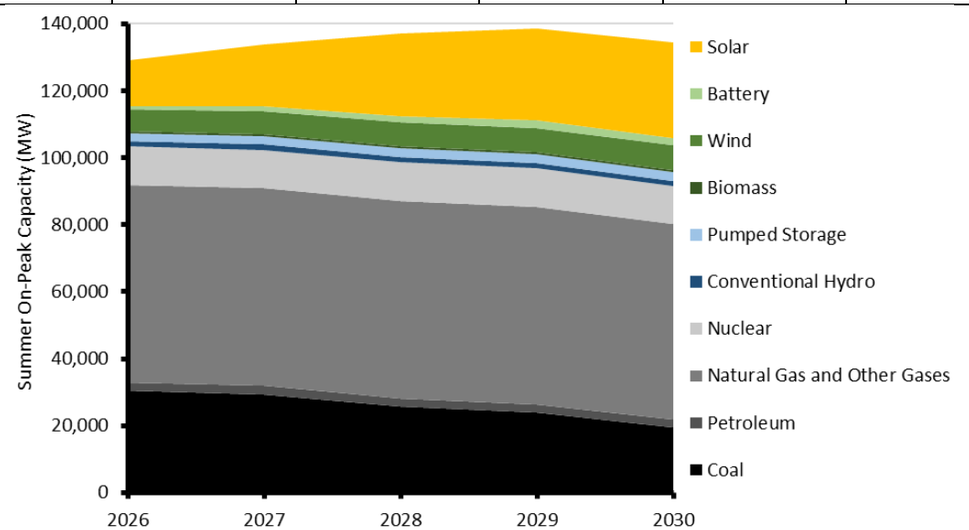
The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations and energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 79,000 miles of transmission lines and approximately 1,979 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	127,071	131,107	135,998	138,286	139,631	140,959	142,003	142,789	143,754	143,754
Demand Response	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280
Net Internal Demand	118,791	122,827	127,718	130,006	131,351	132,679	133,723	134,509	135,474	135,474
Additions: Tier 1	5,576	13,339	21,350	24,631	26,027	26,320	26,366	26,366	26,366	26,366
Additions: Tier 2	2,403	6,723	10,072	13,056	13,116	13,260	13,364	13,466	13,466	13,466
Additions: Tier 3	1,632	4,459	9,395	14,474	19,823	23,820	27,983	27,858	27,915	28,077
Net Firm Capacity Transfers	2,809	2,661	2,509	2,509	2,419	2,419	2,419	2,419	2,419	2,419
Existing-Certain and Net Firm Transfers	126,263	123,205	118,481	116,593	110,996	108,686	106,448	106,568	106,553	106,553
Anticipated Reserve Margin (%)	11.0%	11.2%	9.5%	8.6%	4.3%	1.8%	-0.7%	-1.2%	-1.9%	-1.9%
Prospective Reserve Margin (%)	13.0%	16.6%	17.4%	18.7%	14.3%	11.7%	9.3%	8.8%	8.1%	8.1%
Reference Margin Level (%)	8.1%	8.3%	8.5%	8.5%	8.5%	8.6%	8.7%	8.8%	8.9%	8.9%



Planning Reserve Margins



Existing and Tier 1 Resources

MISO Highlights

- For Summer 2026, MISO projects a prospective resource surplus ranging from 3.4 to 5.8 GW, but, if historical rates of resource additions continue, a deficit of resources beginning in Summer 2030 may be realized. The recently approved ERAS is expected to result in a considerable amount of new resource additions to the MISO system by 2029, which was not included in this year's assessment due to the timing of FERC approval. As of December 2025, around 30 GW of new capacity is being studied through the ERAS process.
- MISO forecasts that the coincident total internal demand will peak at 127.1 GW during the 2026 Summer season and will grow to 143.7 GW by 2035. The largest contributor to this demand growth is data center additions.
- MISO's accredited thermal capacity has decreased by 8.8 GW, primarily driven by reductions in accredited capacity of existing resources, and accredited non-thermal capacity has increased by 5.7 GW since last year, primarily driven by solar additions.
- In July 2025, MISO had more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that were projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity.
- Currently, MISO has surplus transfer capacity within its subregions, but transfers between subregions have been historically constrained by a transmission limitation between the two subregions. MISO members plan to invest $30 billion to install nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines to address local, regional, and interregional transmission needs.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	30,442	29,376	25,620	23,780	19,384
Petroleum	2,551	2,551	2,551	2,551	2,428
Natural Gas	58,748	58,892	58,984	59,099	58,262
Biomass	585	580	516	515	512
Solar	13,586	18,496	24,792	27,499	28,629
Wind	6,576	6,757	7,139	7,258	7,379
Conventional Hydro	1,521	1,523	1,524	1,524	1,524
Pumped Storage	2,608	2,608	2,608	2,608	2,608
Nuclear	11,571	11,571	11,571	11,571	11,571
Other	68	68	68	68	63
Battery	774	1,462	1,950	2,243	2,243
Total MW	**129,031**	**133,883**	**137,322**	**138,715**	**134,604**

MISO Assessment

MISO's guiding principles for its planning process include six key objectives: reliability and resilience; economic efficiency/lowest total electric system cost; support of federal, state, and local energy policy and member goals for their respective resource mixes; appropriate cost allocation for transfer-enabling assets; analysis of an appropriate range of system scenarios and dissemination of results to relevant decisionmakers; and coordinated planning processes among neighbors to eliminate barriers to reliable and efficient operations. See MISO's Statement of Guiding Principles for more information.

Planning Reserve Margins

Every year, MISO coordinates with its stakeholders to calculate the minimum amount of capacity above coincident peak demand required such that the LOLE equals one-day-in-10 years, or 0.1 days per year. For the MISO-wide analysis, generating units were modeled as part of their appropriate local resource zone as a subset of a larger MISO system. The MISO system was modeled with no internal transmission limitations between zones. To meet the LOLE reliability criteria, capacity is either added or removed from the MISO system within the model. The minimum amount of capacity above the MISO system coincident peak demand forecast required to meet the LOLE reliability criteria was used to establish seasonal Planning Reserve Margin (PRM) values. This minimum PRM is based on a probabilistic analysis and is expressed for each season as an unforced capacity (UCAP) requirement based on the modeled availability of resources in the MISO system. UCAP represents an adjustment from installed capacity (ICAP) that accounts for a generator's equivalent forced outage rate demand, a measure of the probability that a generating unit will not be available due to forced outages, which MISO further adjusts to exclude events outside management control.

MISO's LOLE Study for PY 2025–2026 estimated the minimum seasonal PRM values (in UCAP) as follows:

- Summer 2026: 8.1%
- Fall 2026: 14.9%
- Winter 2026-2027: 19.1%
- Spring 2027: 26.2%

The study that produced these PRM values included a probabilistic risk modeling and power flow transfer analysis to also determine zonal local reliability requirements (LRR), zonal import ability (ZIA), zonal export ability (ZEA), capacity import limits (CIL), and capacity export limits (CEL). A software program called Strategic Energy & Risk Valuation Model (SERVM) was used to calculate LOLE for the applicable planning year.

The results of the LOLE Study for PY2 5-26 serve as inputs to the MISO Planning Resource Auction (PRA). The computed PRMs are used in area adequacy assessments unless an area includes an entity that falls under a state regulatory body's purview, in which case a state-mandated PRM may be used in MISO's analysis in place of the computed PRM.

In most of the MISO footprint, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy. Every year, MISO collaborates with the Organization of MISO States (OMS) to survey its members about their plans to maintain resource adequacy in the coming years. The OMS-MISO survey provides a resource adequacy view for the MISO region over a five-year horizon based on the latest information available at the time of survey. The 2025 OMS-MISO Survey indicated that LSEs are expected to have adequate resources to meet load reserve requirements; however, various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.

For Summer 2026, MISO projects a prospective surplus ranging from 3.4 to 5.8 GW. Moving beyond the short term, if historical rates of resource additions continue in MISO as reflected in the anticipated resources projection for the NERC LTRA, a deficit of resources beginning in summer 2030 may be realized. This potential shortage is due to accelerated load growth and inadequate build rates for new resources. Interconnection of additional identified resources in Tier 2 and potential resources in Tier 3 could present an opportunity to retain a resource surplus through the entirety of the LTRA study time frame.

In anticipation of resource shortages beginning in Summer 2030, MISO has initiated the following processes and reforms:

1. Implement the interim ERAS process to facilitate the accelerated rollout of new resources to meet increased demand growth. This process has yielded nearly 30 GW of potential new capacity as of December 2025.
2. Move to a direct loss of load (DLOL) marginal accreditation model for the 2028–2029 planning year, which is intended to better reflect the true value of the next megawatt of resources during critical hours
3. Enhance resource adequacy risk assessment and communication like aligning solar representations between the PRA and LOLE model, properly represent non-firm imports between neighboring regions, and investigate the relationship between solar and battery installations and how their capacity might impact one another.
4. Reduce queue cycle times through automation

5. Establish a more robust DR and emergency resource process moving forward to ensure non-market units are being appropriately accredited.
6. Enhance allocation of resource adequacy requirements.

Energy Risk

MISO uses a seasonal PRA and conducts seasonal resource assessments to evaluate generation availability, outage rates, and forecasted load. Based on outcomes of these processes, MISO has also initiated a change to its capacity market construct, in part, to ensure energy adequacy by evaluating how classes of resources and each individual resource help serve load during periods of the year that demonstrate the most reliability risk to the MISO system.

Beyond the probabilistic energy risk assessments associated with MISO's LOLE Study for PY 25–26, MISO has also performed additional assessments for renewable integration and regional resource evolution that touch on the topic of energy risk but are not a formal part of MISO's resource adequacy and resource planning processes.

ProbA Results

The results of the ProbA simulations show normal risk for the MISO system in study year 2027 and more pronounced, elevated risk in study year 2029 wherein MISO assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and have the ability to address uncertainties associated with these three variables.

MISO initiatives like ERAS and joint collaborative efforts between MISO, its membership, regulators, and neighboring regions will be critical to ensuring resource adequacy in the coming years.

While overall installed nameplate capacity across the system is expected to increase in the coming years, system risk can be expected as the aging thermal fleet in MISO's system continues to retire and is replaced with more intermittent, less available generation. Significant demand growth, in part due to large data center loads, has been forecasted by MISO's LSEs. It is important to note that a substantial number of large-load customers continue to evaluate their options for participation in the markets, including the potential to participate as DR resources during emergency conditions. The construction delays for new resources due to supply chain and other issues, as well as the ongoing evaluation of large-load customers, contribute to continued uncertainty regarding both overall resource availability and the prospective participation of large loads as DR resources in the markets. This substantiates that MISO, its membership, and regulators must continue to monitor retirements and large-load additions and increase resource additions to ensure future resource adequacy.

The ProbA simulations for study year 2029 resulted LOLE of 2.4 days in 1 year compared to the target of 0.1 day in 1 year. The primary drivers for the expected risks in 2029 include the following:

- Load growth increases: Peak demand for winter is expected to grow considerably—approximately 9–10 GW in 2029.
- Nameplate capacity changes: To align with MISO's annual LOLE studies and proactively send the right signals, member-submitted low certainty resources from the most recent OMS-MISO Survey were assumed to be unavailable in study year and amounted to approximately 14 GW of additional unconfirmed retirements by Winter 2029.
- Summer risk shifts to later in the day: An increased reliance on solar generation as the resource mix evolves results in summer risk appearing as solar generation ramps down.
- In Winter 2029, risk is emerging in morning and twilight hours: Shifting winter risk is driven by a combination of increased reliance on solar generation, an increase in member-submitted load forecasts, elevated thermal forced outages induced by extreme cold temperatures, and a larger generation deficit than in prior years.

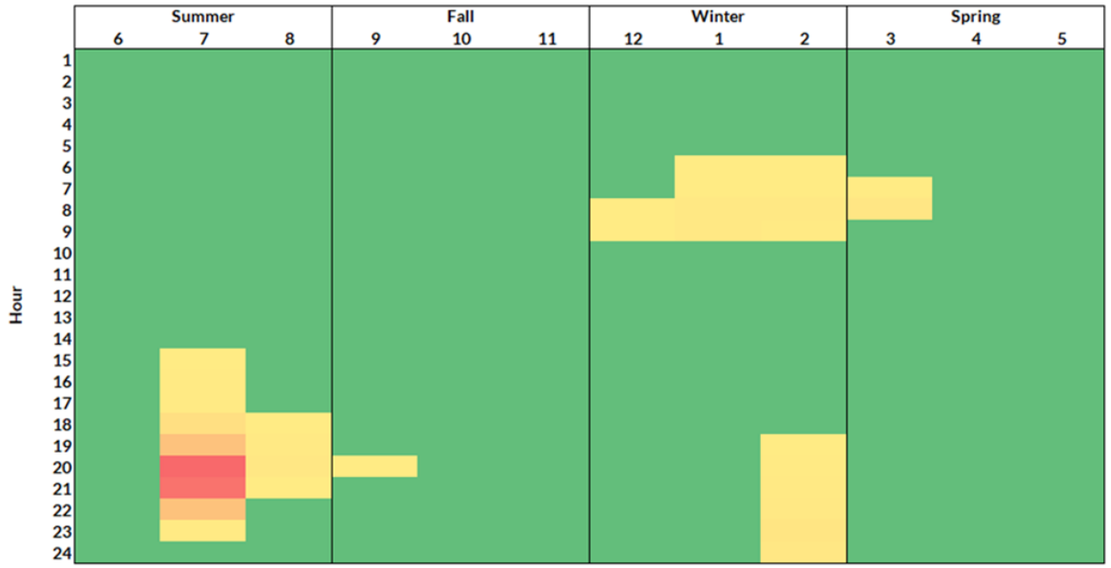
Base-Case Summary of Results

	2026*	2027	2029**
EUE (MWh)	0	797	31,654
NEUE (ppm)	0	1.13	42.4
LOLH (hours per Year)	0	0.23	6.61

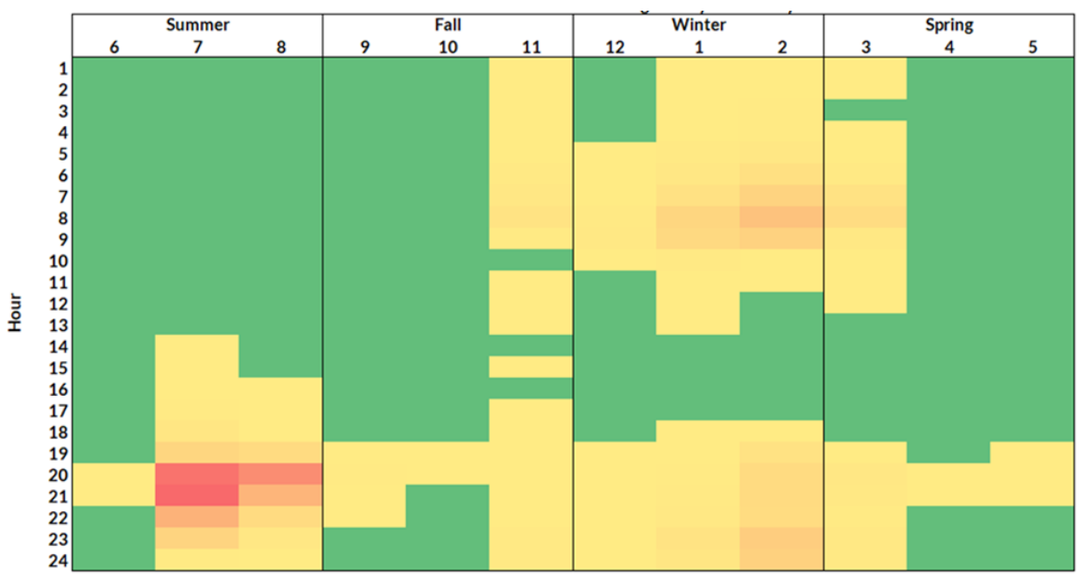
*Provides the 2024 ProbA Results for Comparison

**The 2029 ProbA study assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis.

The following EUE heat maps show the distribution of unserved energy events from the probA simulations across hours and seasons. Green cells indicate no unserved energy events, while yellow and red cells indicate increasing numbers of simulations with unserved energy.



2027-2028 ProbA Heat Map



2029-2030 ProbA Heat Map

Demand

LSEs within MISO's footprint report two sets of seasonal peak demand projections, coincident with the entire MISO system and coincident with their applicable local resource zone. LSEs also submit their non-coincident peak demand projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. Coincident peak demand forecasts are based on factors including average historical weather conditions, economic conditions, and expected demand changes. For the *2025 LTRA*, MISO used its LSE demand submissions to create non-coincident and coincident peak demand projections on a regional basis by summing the annual peak demand forecasts for the individual LSEs in the larger region of study. In MISO's normal process, the coincident peak demand forecast is used to determine each LSE's PRM requirement.

MISO forecasts the coincident total internal demand to peak at 127,071 MW during the 2026 Summer season. Since the *2024 LTRA*, MISO has increased its 10-year forecast peak demand from 132 GW to 143.7 GW. This rate of increase is expected to continue.

The largest increases in demand in the MISO footprint are related to data centers. These large load additions are projected to result in significant increases in the demand for energy in all hours and would not conform to typical residential or industrial load patterns. In total, MISO projects approximately 6 GW of data center load additions by 2027, accumulating to 14 GW by 2030, and 18 GW by 2035. MISO published a *Long-Term Load Forecast* white paper in December 2024. This white paper comes to similar conclusions around the load growth rate based upon member submissions by way of the MOD-031/FERC 714 data pathway.

Demand-Side Management

A combination of peak demand hour performance, forecasting, and baseline scenarios help MISO to determine the amount of DR capacity available during peak demand hours. DR programs continue to play a significant role in providing capacity for MISO. For the 2025/26 planning year, DR is steady around 9 GW in the summer and 8 GW in the winter and is projected to remain constant during the LTRA study horizon. MISO's latest reforms for demand-side resources focus on accrediting such resources based on their availability and performance during the highest-risk hours (in and near emergency conditions).

Distributed Energy Resources

Behind-the-meter-generation (BTMG) resources contribute about 4.4 GW of capacity across the study horizon, of which approximately 1.3 GW are distributed photovoltaics. MISO's transition to seasonal auctions highlights the variability of DERs across the four seasons, and it is working with stakeholders to derive adequate methods of aggregating, reporting and allowing DER participation in MISO markets.

Generation

Because of the size of MISO's interconnection queue, in the 2025 NERC LTRA, generation in the queue is multiplied by a reduction factor based on the study phase and likelihood of that resource coming on-line and the timing of those additions. MISO notes that the recent 2025 OMS-MISO survey used a slightly different resource addition cadence than what is reported for the LTRA that factors in both planned utility/member-specific generation addition rates and historical addition cadences. Specifically, the LTRA's existing resource capacities come directly from the 2025–2026 MISO Planning Resource Auction (PRA), based on the amount of confirmed seasonal accredited capacity. Tier 1 resources describe the expected integration rate of currently signed generator interconnection agreements (GIA) over a three-year delay ramp to represent the fact that many GIAs experience delays on their path to installation in MISO. Tier 2 resources are based on active replacement projects and Phase 3 GIAs. Tier 3 resources are based on a 15% completion rate of all non-signed GIAs with the three-year delay schedule in line with Tier 1 resources.

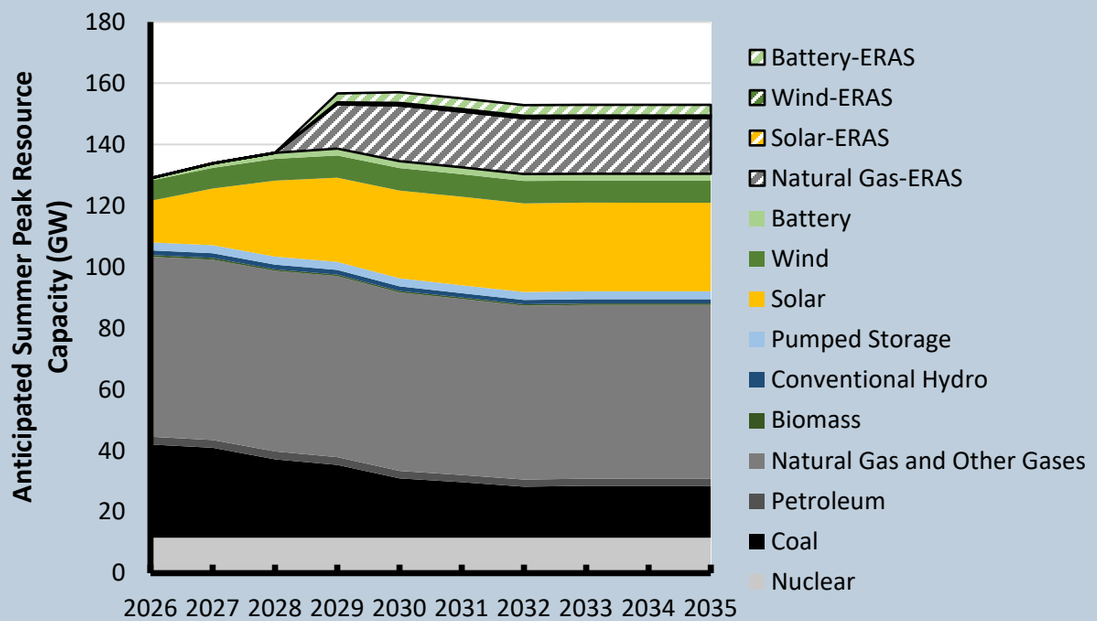
As of December 2025, MISO had more than 70 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. Since the 2024 NERC LTRA, MISO has observed an 8.8 GW reduction in thermal accredited capacity, driven primarily by aging existing facilities, unit suspensions, and retirements. However, suspensions and retirements in MISO have recently been followed by replacement facilities that re-utilize the interconnection service with new units. More than 75% of the units pursuing cessation in MISO are also pursuing replacement projects. Non-thermal accreditation has increased by 5.7 GW since the 2024 NERC LTRA report.

MISO's accreditation of battery resources is tied to the mandatory 4-hour energy offer window, resulting in most storage resources pursuing the ratio of 1 MW/h for 4 hours. Battery storage resources receive a 95% class-wide accreditation (relative to nameplate capacity) in the MISO PRA and NERC LTRA for their first year in operation in lieu of historical output data. Wind ELCC analyses have been performed for all seasons. Wind capacity is given the following seasonal accreditations: Summer: 20.8%; Fall: 30.7%; Winter: 29.0%; Spring: 25.3%. The effective capacity for existing solar resources is based on historical performance during typical seasonal peak hours. New solar resources get 50% accreditation relative to nameplate capacity in the summer, fall, and spring seasons and 5% in the winter season. Hydro resources accredited capacity is calculated based on historical performance during seasonal peak hours.

Energy Storage

MISO is experiencing increased interest by members for battery energy storage, with more than 500 MW currently on-line, and queue projects identifying more than 100 GW of battery or hybrid fuel type projects. MISO's anticipated installations include an addition of more than 2.4 GW by Summer 2030 and a prospective battery fleet of nearly 7 GW by 2035. The primary expected usage for batteries is for reliability, providing significant capacity capability with the variable nature of MISO's growing solar and wind fleet. MISO performs risk modeling with advanced storage representations to ensure that battery capacity is characterized appropriately.

The timing of FERC's approval of MISO's ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the 2025 LTRA. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from the ERAS program is expected to grow to over 20 GW by Summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year's ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the *2026 LTRA* and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



The Potential Effect of MISO's ERAS Process on Anticipated Summer Capacity

Energy Transfers
In the PRA, MISO accredits several power purchase agreements known as diversity contracts between Manitoba Hydro and MISO internal generation owners, wherein energy flows from Manitoba to the MISO system in the summer when Manitoba has excess hydro power vice-versa in the winter. Currently, MISO has surplus capacity in both the MISO North/Central and MISO South subregions, but imports and exports between them have been historically constrained by a transmission limitation.

A key input to MISO's probabilistic risk modeling that determines the system-wide seasonal PRM values is how much non-firm energy support MISO can reasonably expect from neighboring external areas. Every year, MISO performs an analysis of recent year trends in seasonal non-firm energy support to develop a range for each season that the probabilistic model will randomly draw from mid-simulation. Additionally, MISO found this year that there was not a significant difference in the amount of non-firm energy support MISO received from its neighbors during hours and days with tight operating margins when compared to normal operating conditions.

Transmission
MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure system reliability. Many factors are considered during MISO's transmission expansion planning process, including urgency of need, suitability of alternatives to address identified issues, cost effectiveness, performance of alternatives, development time frame, right-of-way or substation impacts, expandability, and operational flexibility. To learn more about MISO's transmission expansion plan, see information and reports posted on MISO's MTEP page.

MISO has 488 transmission projects totaling $30 billion planned across MTEP24, its Long Range Transmission Planning (LRTP) Tranche 2.1, and the SPP-MISO Joint Targeted Interconnection Queue (JTIQ). In total, these three programs include nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines in their project portfolios. These projects aim to address local, regional, and interregional needs across the area's large geographic footprint by enabling reliability in response to accelerating load growth. In fact, most of the demand increases reported by LSEs in the MISO footprint can be tracked to transmission projects either in the Expedited Project Review (EPR) or normal MTEP project pathway. Specifically, MISO's Tranche 2.1 Portfolio seeks to establish a transmission system backbone for the whole MISO system, and the JTIQ portfolio is being undertaken with the potential to unlock approximately 28 GW of generator interconnections, eliminating barriers to new capacity at the SPP-MISO seam.

As of December 1, 2025, MISO identified 63 projects comprising 12.8 GW of additional load through the EPR process.

Reliability Issues
Load growth and additions are increasing. A spike in large, single-site load additions from manufacturing resurgence and incremental load growth from electric vehicles and other electrification trends pose new challenges for the grid. Continued high numbers of MTEP projects submitted through the expedited project review request, which are urgent projects that cannot wait for the next full MTEP cycle to proceed, are evidence of this faster paced load growth and additions.

Maintaining resource capacity margins will require accelerated resource additions to outpace retirements and the forecasted load growth. Recent reforms have helped to reduce the volume of requests and to process them more efficiently. As of December 1st, 2025, MISO has 1,127 Active interconnection queue projects that total 215 GW of nameplate capacity. This is in addition to the 444 projects and 70 GW of signed GIAs.

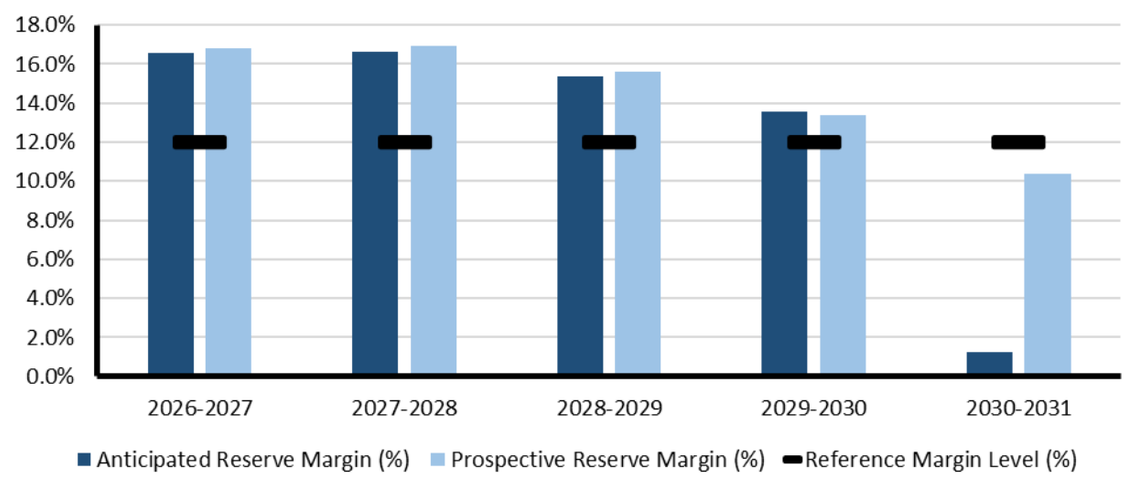


MRO-Manitoba Hydro

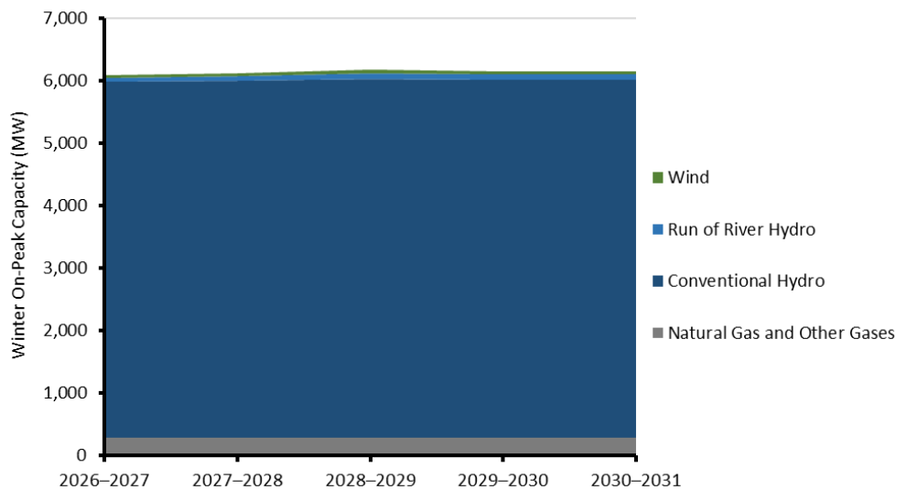
Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own PC and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Additions: Tier 1	36	50	63	63	63	63	63	63	63	63
Additions: Tier 2	0	0	0	0	500	500	500	500	500	500
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-93	-167	-172	-565	-565	-565	-565	-565	-315
Existing-Certain and Net Firm Transfers	5,794	5,831	5,799	5,770	5,377	5,377	5,377	5,377	5,377	5,627
Anticipated Reserve Margin (%)	16.6%	16.7%	15.4%	13.6%	1.2%	0.5%	-0.1%	-1.2%	-2.5%	0.6%
Prospective Reserve Margin (%)	16.8%	16.9%	15.6%	13.4%	10.4%	9.6%	8.9%	7.7%	6.3%	9.3%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-Manitoba Hydro Highlights

- Manitoba projects a shortfall in anticipated resources starting in the winter of 2030–2031.
- The demand is projected to grow over 13% through the assessment period.
- The Province of Manitoba paused cryptocurrency interconnection requests until April 2026 to prepare a long-term solution to limit reliability impacts to the system.[36]

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
Natural Gas	278	278	278	278	278
Wind	52	52	52	52	52
Conventional Hydro	5,705	5,723	5,758	5,735	5,735
Run of River Hydro	59	71	90	90	90
Total MW	**6,094**	**6,124**	**6,179**	**6,155**	**6,155**

[36] Province directs Manitoba Hydro to continue pause on new cryptocurrency connections

MRO-Manitoba Hydro Assessment

Planning Reserve Margins
The ARM for the summer season does not fall below the RML of 12% during the 10-year assessment period. The ARM for the winter season falls below the RML of 12% beginning in Winter 2030–2031 due to a combination load growth and reduced resources due to an ending of winter capacity import contracts ("diversity capacity") in 2030, as well as an assumed reduction of the Curtailable Rate load management program.

Demand
Manitoba Hydro is anticipating load growth of 1.5% (net of demand side management) over the assessment period. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management
Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five-minutes notice. The program is intended for peak load management. In addition, one product of the Curtailable Rate Program provides 50 MW of contingency reserves, also on five-minutes notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Manitoba Hydro is in the process of developing a new industrial rate pilot, with the combined goal of reducing winter peak and providing additional rate options for customers that both assist customer profitability and help keep costs low for all Manitobans. The rate pilot is being developed to leverage existing technology and programming with the intent of introducing the program on a pilot basis.

Manitoba Hydro, in collaboration with Efficiency Manitoba, is looking to develop a DR pilot program aimed initially at targeting smart thermostats with the focus on reducing Manitoba's winter peak. The pilot program is targeting to launch for the winter of 2025.

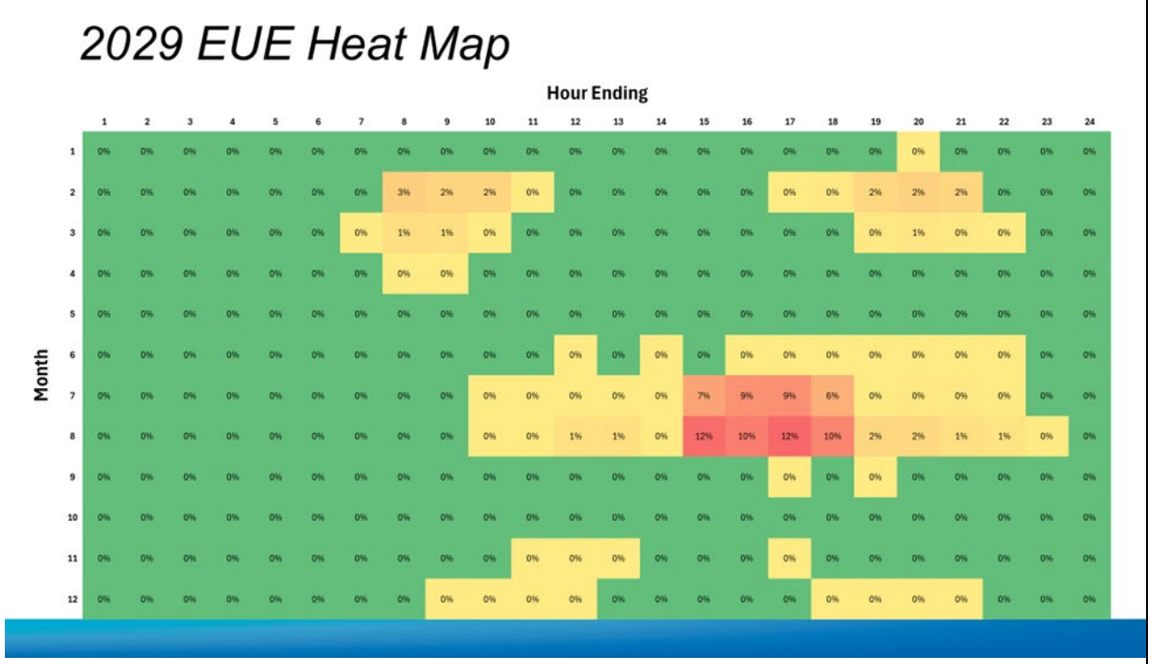
Energy Risk
As the operator of a predominantly hydro system, weekly at a minimum, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis as required to manage near-term to seasonal-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements that would be required to maintain Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to fall at or very near the peak demand hours.

Probabilistic Assessment (ProbA)
Every year, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2024. The 2024 probabilistic assessment was supportive of a 12% PRM for the Manitoba system being sufficient to provide an LOLE of less than 0.1 days per year under the study assumptions. Results of the 2025 ProbA prepared for the LTRA are as follows.

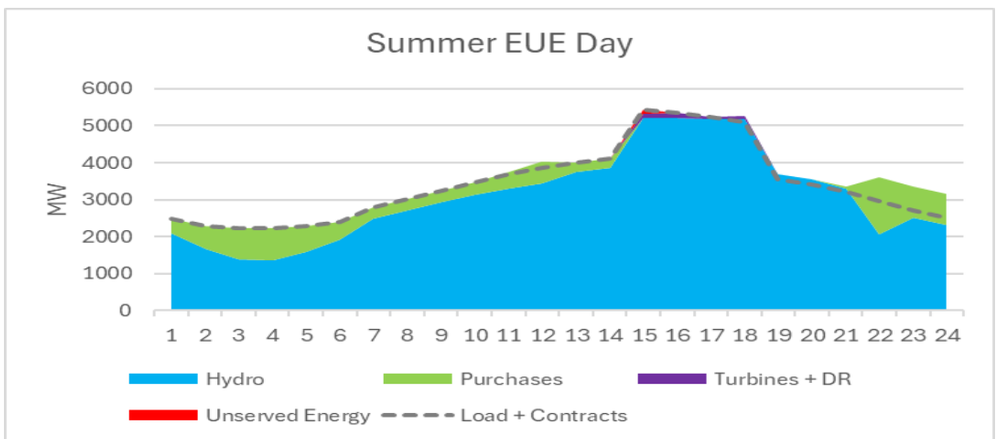
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	4	3	6
NEUE (ppm)	0.17	0.12	0.23
LOLH (hours per Year)	0.05	0.03	0.06
* Provides the 2024 ProbA Results for Comparison			

There were no appreciable Manitoba loss-of-load events seen in winter or in the summer for 37 of the 44 weather/ flow years studied. Manitoba loss-of-load events that were seen in summer occurred during the lowest flow years with upwards of 80% of the risk of loss of load occurring in the two worst flow years (1988 and 2003) of the 44 years studied. The Manitoba loss-of-load events that were seen in summer were driven by very low hydro flow conditions combined with both very high summer loads in Manitoba and very high summer loads on the MISO system.

The annual EUE heat map for 2029 is provided below.



A sample summer EUE day with very high loads on the Manitoba and MISO systems during extreme drought is shown in the illustration below. For much of the day, Manitoba is a net importer of power.



Distributed Energy Resources

There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DERs may be dependent on solar PV subsidies and/or incentives.

Generation

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. A Tier 1 project to replace eight older and smaller hydro units is in progress for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation.

On February 25, 2025, Manitoba Hydro filed with its regulator the preliminary estimate for a 500 MW gas capacity resource entering service in 2030. While not yet approved, this proposed plant was included as Tier 2 capacity resource. Manitoba is not currently experiencing the large additions of wind and solar resources seen in other regions, and hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated over the next five years. Manitoba Hydro is working on an Integrated Resource Plan that will support future investment decisions. The Government of Canada is further regulating carbon dioxide emissions from the electric generation sector, finalizing the Clean Electricity Regulations in December 2024. These regulations begin to restrict fossil fuel generation in 2035 and direct Canadian electric generation to achieve net-zero greenhouse gas emissions by 2050. Manitoba Hydro does not anticipate that meeting the Clean Electricity will have a negative impact on system reliability or modify the operation of Manitoba's electricity system. The Province of Manitoba provided energy policy direction with the publication of the Affordable Energy Plan in September 2024. Energy conservation, wind generation, and dispatchable back-up generation, such as natural gas combustion turbines, form the basis of the plan. Manitoba Hydro's forthcoming 2025 Integrated Resource Plan will be consistent with the policy direction.

Energy Storage

Additions of battery energy storage system (BESS) resources in the next 10 years are not anticipated at this time. The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources on-line are hydro generation resources, which therefore serve most operational, reliability, and economic functions. In the longer term, there may be a role for energy storage resources in Manitoba in areas that may become transmission constrained. Preliminary long-term studies of a modest amount of energy storage resources have not identified

operational challenges and have not required modification to planning assumptions since the 2024 LTRA.

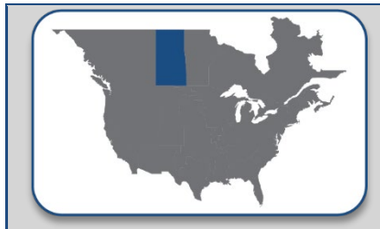
Energy Transfers

The Manitoba Hydro system is winter-peaking and is interconnected to the MISO Zone 1 Local Resource zone (which includes Minnesota and North Dakota), which as a whole is summer-peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts, but only if the following conditions occur simultaneously: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. In the unlikely event of such a situation, Manitoba Hydro would implement plans developed in accordance with emergency operating procedures for capacity and energy emergencies, including calling on emergency energy from Adjacent Balancing Authority Coordination Agreements, if available. Transmission planning studies consider maximum firm winter import and N-1 and N-2 contingencies. The completion of the Manitoba–Minnesota 500 kV transmission line on June 1, 2020, increased import capability from 700 MW to 1,400 MW and firm export capability from 2,100 MW to 2,983 MW. This new 500 kV line also improved the resilience of the network in the event of transmission contingencies. The 500 kV line is equipped with single pole trip and reclose capability, which results in only one phase being out for one second during common single-phase faults.

The expiration of existing winter capacity import contracts ("diversity capacity") in 2030 is contributing to overall lower firm resources from winter 2030–2031 through the remainder of the assessment period.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue, which is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end-of-life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

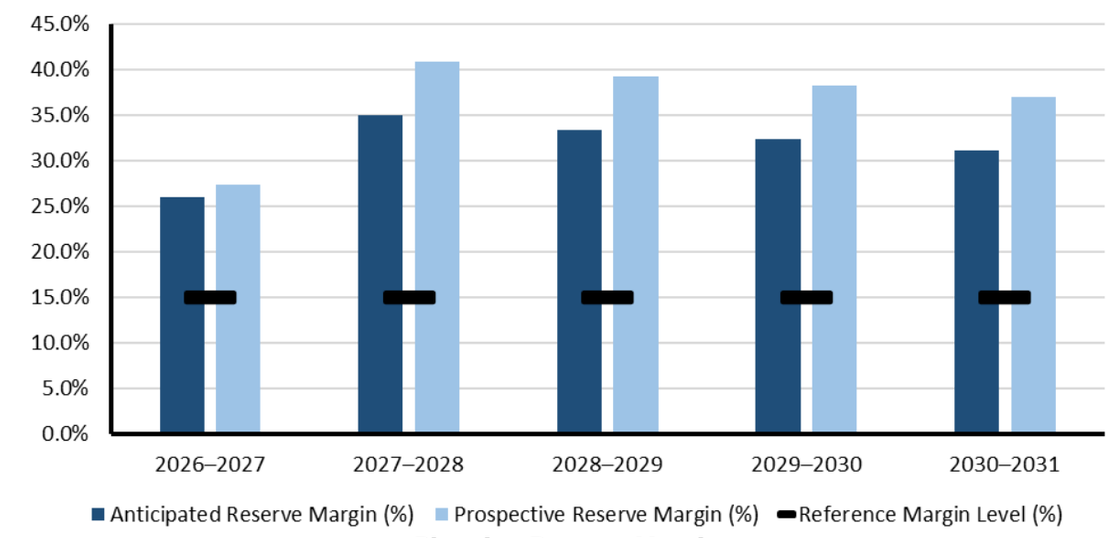


MRO-SaskPower

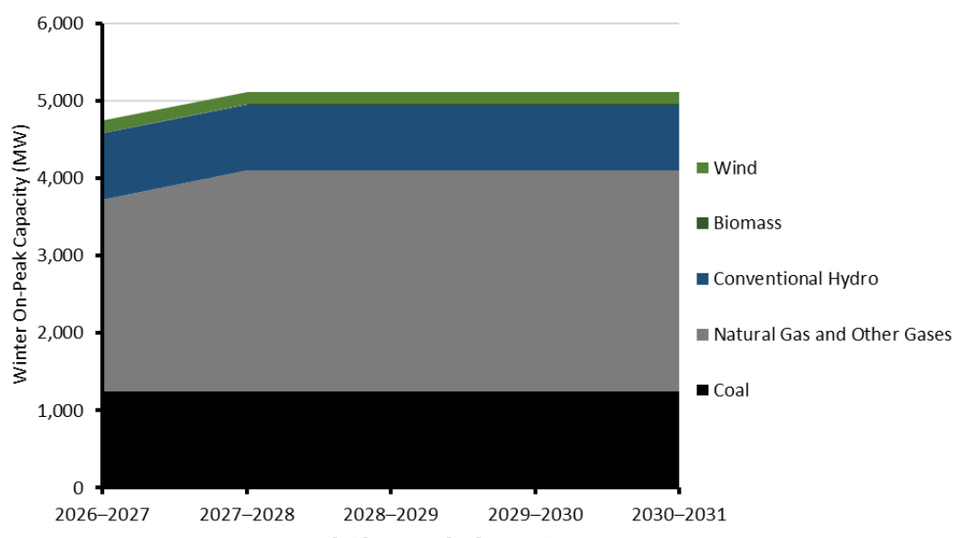
MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	4,040	4,112	4,148	4,180	4,205	4,230	4,278	4,314	4,347	4,375
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,968	4,040	4,076	4,108	4,133	4,158	4,206	4,242	4,275	4,303
Additions: Tier 1	90	460	460	460	460	460	460	460	460	460
Additions: Tier 2	55	241	241	241	241	241	241	241	241	241
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	315	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,907	4,992	4,976	4,976	4,961	4,962	4,900	4,962	4,976	4,892
Anticipated Reserve Margin (%)	25.9%	35.0%	33.4%	32.3%	31.2%	30.4%	27.4%	27.8%	27.2%	24.4%
Prospective Reserve Margin (%)	27.3%	40.9%	39.3%	38.2%	37.0%	35.5%	32.5%	32.8%	32.1%	29.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SaskPower Highlights

- Over the next 10 years, MRO-SaskPower's ARM ranges from approximately 24% to 35% and does not fall below the RML in any year. SaskPower's recent probabilistic studies concluded that the largest contribution to EUE occurs during peak hours because of planned outages. Rescheduling maintenance can help avoid these issues.
- Saskatchewan's average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period. Large industrial loads are the primary driver for both growth and uncertainty in SaskPower's forecast.
- SaskPower is projected to increase its wind and solar capacity to 1,550 MW in the next three years. Natural-gas-fired generation is being added to the system to offset VERs with plans to add 525 MW nameplate of new gas-fired generation—460 MW of Tier 1 and 65 MW of Tier 2—over the next 10 years. Life extensions and repowers for coal units are in process as directed by the Saskatchewan government. SaskPower is anticipating 31.8 MW of confirmed retirements, both waste heat and wind. 174 MW of unconfirmed wind retirements may also occur over the next 10 years.
- Driven by load growth, new generation, and reliability, SaskPower is planning to expand its interconnection with SPP and add 500 MW of new transmission service over the next five years, increasing tie-line capacity to 650 MW total. Internal transmission projects totaling 180 km of new 230 kV lines are being added and an additional ~410 circuit km of transmission projects are in planning and conceptual phases over the next 5 to 10 years.
- SaskPower's primary reliability issues include growing supply chain issues that may potentially affect their significant transmission project plans and an interdependence between Southeast Saskatchewan's power generators and natural gas production fields. SaskPower has been managing these issues by scheduling long-lead-time components as early as possible in transmission project timelines and by working with Saskatchewan's gas pipeline utility to coordinate and study gas system responses to losses of production receipts during power outages as incremental demand is added.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
Coal	1,249	1,249	1,249	1,249	1,249
Natural Gas	2,480	2,850	2,850	2,850	2,850
Biomass	3	3	3	3	3
Wind	164	162	162	162	162
Conventional Hydro	856	856	856	856	856
Other	17	17	1	1	1
Total MW	**4,769**	**5,137**	**5,121**	**5,121**	**5,121**

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses two criteria for determining adequate generating capabilities. The first method is to calculate EUE through probabilistic modeling and maintain it within an acceptable level as determined through resource adequacy analysis. The second method employs a deterministic criterion in which the reserve margin for the Saskatchewan system must not fall below the RML.

Saskatchewan uses a RML of 15% and has assessed its PRM for the upcoming 10 years considering summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available DR for each year. During the 10-year assessment period, Saskatchewan's ARM ranges from approximately 24% to 35% and does not fall below the RML in any year.

Energy Assessment, Including Non-Peak Hour Risk

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. A detailed representation of the SaskPower system that includes load forecasts, capacity expansion sequences, individual unit characteristics, maintenance, and outages are included in the model. For VERs, SaskPower uses the ELCC methodology to periodically update capacity credits in the model. The model simultaneously considers many types of randomly occurring events, such as forced outages of generating units. Uncertainty in assumptions is addressed through scenario work based on the likelihood of occurrence (e.g. high/low hydro energy forecast, high/low load forecast).

These studies conclude that the majority contribution to the EUE is typically planned outages with unserved energy occurring mainly during peak hours. These short-term reliability issues, when identified, can be mitigated by rescheduling maintenance.

ProbA Results

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix majorly consists of baseload and fast-ramping generation resources, and it does not have a considerable penetration level of intermittent energy resources.

The major contribution to the EUE is planned outages. The contribution to EUE in these months occurs mainly during peak hours. These short-term reliability issues when identified can be mitigated by rescheduling the maintenance.

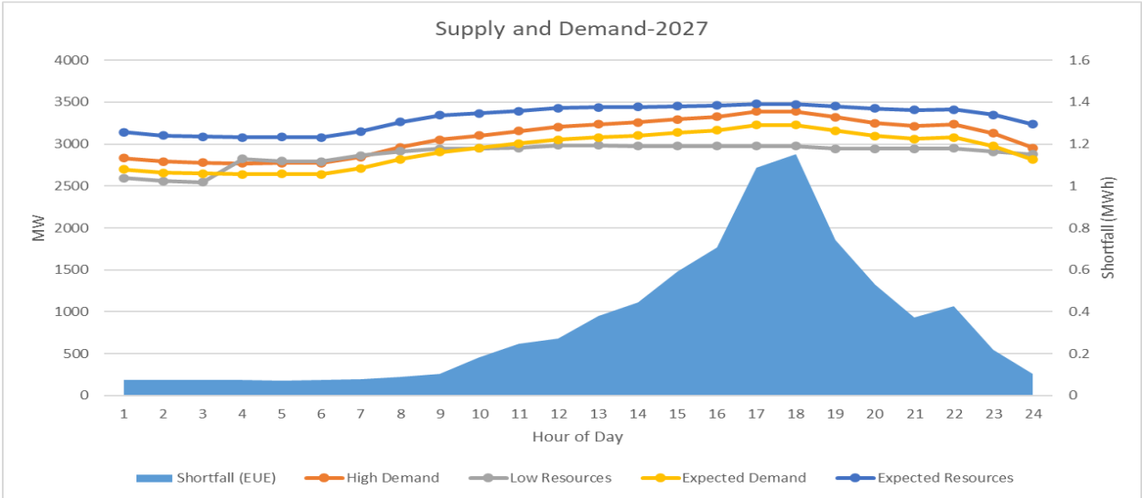
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	75	145	5
NEUE (ppm)	2.807	5.242	0.190
LOLH (hours per Year)	0.547	1.094	0.046
*** Provides the 2024 ProbA Results for Comparison**			

The annual EUE heat map for 2027 is provided below.

Hourly EUE Heat Map : 2027

EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Feb-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%
Mar-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Apr-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
May-27	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	3%	3%	3%	3%	4%	5%	5%	3%	3%	2%	3%	2%	1%
Jun-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Jul-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%
Aug-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	2%	2%	1%	1%	1%	1%	0%	0%
Sep-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Oct-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Nov-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Dec-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2027 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, there is a risk of supply shortfalls if demand is higher than expected and resource availability is lower than expected.



Demand

Saskatchewan experiences its peak season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. SaskPower computes a coincident peak by customer category based on a combination of historical data and other factors and aggregates the coincident peaks across classes to compute the system peak.

Large industrial loads continue to be the primary reason for both growth and uncertainty in the forecast. The average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period, down slightly from the *2024 LTRA*'s projection of 1.35% average annual peak demand growth.

Demand-Side Management

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based on conditions specified in established DR programs. The first of these programs provides a curtailable load, with up to 72 MW enrolled currently, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours' notification, but those loads are not included in PRM calculations.

Distributed Energy Resources

The current behind-the-meter DER installed capacity in Saskatchewan is approximately 57 MW, which includes approximately 55 MW of solar PV and approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. Additional behind-the-meter DER installations are incorporated into load forecast models used for supply and transmission planning studies.

Small power producers contribute an additional 5 MW installed DER capacity (in front of the meter) in Saskatchewan. There is currently an existing 14 MW and a potential for up to 6.5 MW of DERs being added in the next year based on the currently approved Power Generation Partner program. These projects are included as generation additions, but their capacity is not currently considered in reliability planning.

Generation

Saskatchewan prepares a 10-year supply plan annually that outlines its generation plan to meet the province's future resource needs. It considers retirements, planned and major overhauls, degradation of unit performance, escalating fuel prices, increasing capital costs, unit operating costs, and regulatory requirements. The installed capacity of non-synchronous/inverter-based generation has recently risen to 845 MW and is expected to increase to approximately 1,550 MW in the near-term planning horizon through the addition of 400 MW of wind and 300 MW of solar in the next three years. SaskPower added 370 MW of natural-gas-fired generation in 2024, which served to offset the increased net demand variations from the 220 MW of VERs added in the same year. This resulted in a slight improvement in ramping performance as compared to the last ramping assessment in 2022. SaskPower plans to add approximately 525 MW of new natural-gas-fired generation over the next 10 years and is also working to extend the life of its operational and recently deactivated coal units as directed by the Saskatchewan government.

Saskatchewan is projecting 31.8 MW (nameplate) of confirmed retirements consisting of 21.2 MW of waste heat recovery generation and 10.6 MW of wind generation. These retirements are driven by the units approaching the ends of their lifespans and terminations of power contracts. An additional 174 MW of unconfirmed wind retirements may also materialize during the 10-year assessment period.

Energy Storage

SaskPower's first battery storage system, a 20 MW/20 MWh unit, came on-line in 2024. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/ voltage control, primary frequency control, and blackstart.

Energy Transfers

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is currently the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity

transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation measures are in place through SaskPower's emergency operating procedure that will allow measures such as short-term imports from available interfaces, initiating DR, and short-term load shedding.

According to the NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the Saskatchewan transmission planning region from all its neighbors, including dc-only interties, is 904 MW in the 2024 Summer and 893 MW in the 2024–2025 Winter. These values translate to approximately 25% of peak summer load and 22% of peak winter load in the analysis years. The interfaces include connections with MRO-SPP, MRO-Manitoba Hydro, and WECC-Alberta.

Transmission

SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 500 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 km of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, installation of two phase-shifting transformer interfaces, and two STATCOMs are being added. The remaining transmission projects (approximately 410 circuit km) will be in the planning or conceptual phases in the 5-to-10-year timeframe. These projects are driven by load growth, new generation additions, and reliability needs. SaskPower has historically experienced transmission limitations for existing generation deliverability in the southwest part of the province during prior outages of major transmission facilities.

Transmission infrastructure is being developed to reinforce the Northern Transmission System. SaskPower's Northern System is not directly connected to the Southern grid, so significant load growth in the North will also require additional generation to supply the additional loads. SaskPower is looking at different ways to supply the generation to this load, including wheeling power from the South to the North through adjacent areas and temporary generation until a more permanent solution can be implemented. Planning for these projects is being driven, in part, by a projected increase in mining activity and associated development in Saskatchewan's remote northern region. Reliable power supplies for new loads in the north will require significant transmission development.

Reliability Issues

As SaskPower is planning on constructing a significant number of transmission facilities, growing supply chain issues may affect project schedules because of long lead times for major system components. SaskPower is identifying and initiating projects earlier that may require longer lead time and is advancing procurement as necessary.

It has been noted that there is an interdependency between Southeast Saskatchewan's power generation and natural gas production. Saskatchewan's pipeline utility, SaskEnergy, has completed analysis on how its system will respond to a loss of natural gas receipts during a power outage in this region as potential incremental demand is added. Both SaskPower and SaskEnergy have incorporated the potential challenges identified by that analysis into long-term planning and mitigation efforts.

SaskPower has been recently observing increasing instances of unscheduled flows on its interface with SPP and Manitoba Hydro. SaskPower is coordinating this on a regional basis with Manitoba Hydro, SPP and MISO to monitor and address the impact.

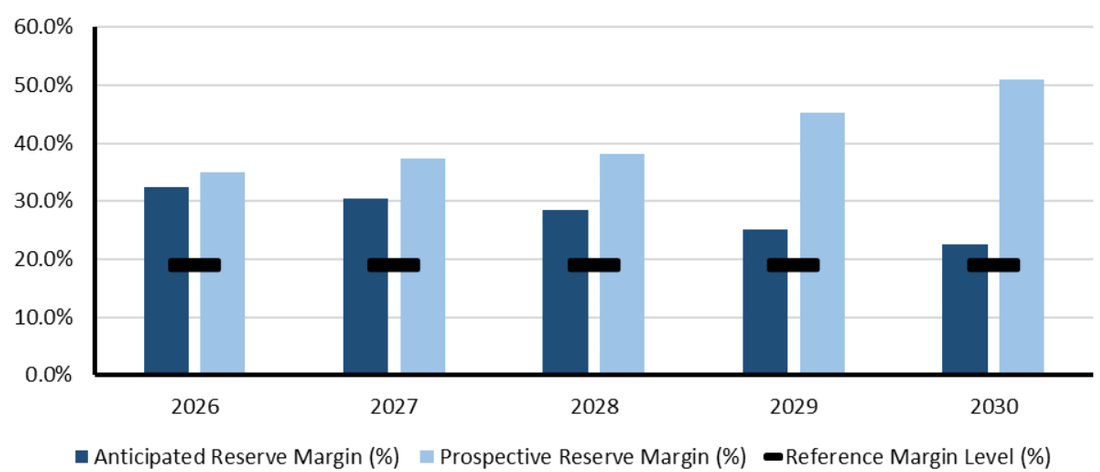


MRO-SPP

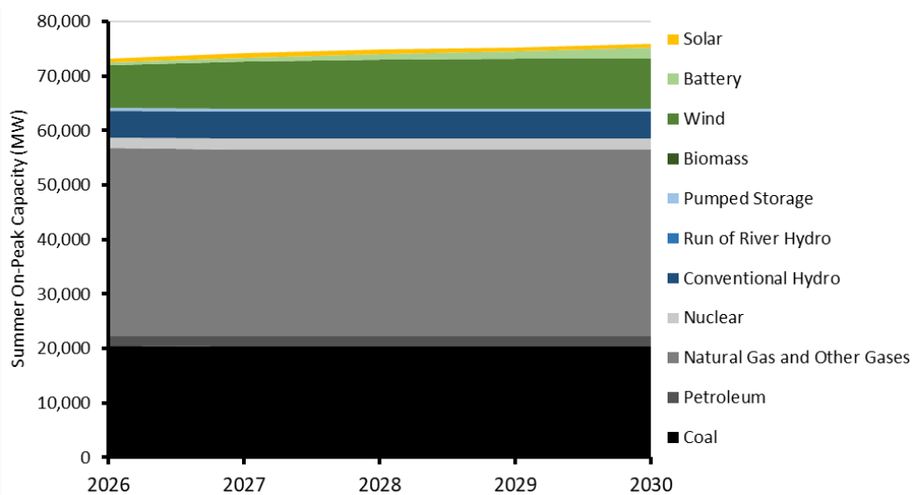
The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	57,479	59,121	60,689	62,766	64,475	66,283	66,982	67,570	68,049	68,622
Demand Response	2,138	2,162	2,332	2,508	2,509	2,511	2,513	2,514	2,718	2,720
Net Internal Demand	55,340	56,959	58,357	60,258	61,966	63,772	64,469	65,056	65,331	65,902
Additions: Tier 1	1,808	3,020	3,685	4,251	4,815	4,866	5,344	5,344	5,344	5,344
Additions: Tier 2	2,436	6,104	8,948	15,659	21,487	23,345	25,664	27,277	27,877	28,627
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-18	-78	-78	-78	-78	-79	-79	-79	-79	-79
Existing-Certain and Net Firm Transfers	71,475	71,224	71,232	71,127	71,146	71,115	71,135	71,106	71,105	71,106
Anticipated Reserve Margin (%)	32.4%	30.3%	28.4%	25.1%	22.6%	19.1%	18.6%	17.5%	17.0%	16.0%
Prospective Reserve Margin (%)	34.9%	37.3%	38.2%	45.2%	50.9%	48.7%	51.5%	51.8%	51.8%	50.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SPP Highlights

- The SPP assessment area peak demand occurs during the summer season; the 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023.
- SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026.
- The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	20,473	20,440	20,440	20,428	20,428
Coal*	19,187	19,154	18,086	18,075	18,075
Petroleum	1,824	1,827	1,827	1,827	1,829
Petroleum*	1,824	1,771	1,771	1,771	1,774
Natural Gas	34,525	34,303	34,303	34,265	34,265
Natural Gas*	34,363	33,662	33,550	33,512	33,268
Biomass	35	35	35	35	35
Solar	700	700	700	700	700
Wind	7,831	8,581	9,044	9,134	9,191
Conventional Hydro	4,925	4,993	5,009	5,026	5,030
Pumped Storage	456	456	456	415	460
Nuclear	1,945	1,945	1,945	1,945	1,945
Other	281	281	281	281	281
Battery	379	833	1,027	1,472	1,949
Total MW	73,429	74,450	75,123	75,584	76,168
Total MW*	71,981	72,467	71,960	72,422	72,762
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

MRO-SPP Assessment

Planning Reserve Margins

The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029. SPP has approved a non-coincident 16% PRM for the 2026 Summer season and a 36% PRM for the 2026–2027 Winter season. Additionally, a non-coincident 17% PRM for the 2029 Summer season and 38% PRM for the winter season was approved as well. The PRM increases are not reflected in the *2025 LTRA* as they are tied to policies that are still before FERC. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to drop below the current 19% RML in 2032 and remain below that RML for the remainder of the 10-year horizon.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

SPP is performing a yearly energy adequacy assessment and assessment of adequacy of reliability attributes, which will be presented to SPP stakeholders. The results will also be used to perform for all reliability attributes a biennial assessment of the need for new market products, changes to market functionality, and changes to resource adequacy policies or requirements. Results of the biennial reassessment will be provided to impacted SPP stakeholder groups and the Regional State Committee (RSC).

Southwest Power Pool (SPP) performs an LOLE analysis every two years to determine the adequate amount of planning reserves needed to maintain a reliability metric of one day (or less) in ten years. SPP's 2023 LOLE study supported much of the demand forecast presented in NERC's *2024 LTRA* and demonstrated how the PRM could be impacted materially depending upon how much loss of demand risk was planned for each season (winter or summer). Directed by the RTO's Resource and Energy Adequacy Leadership Team, SPP completed an out-of-cycle 2024 LOLE analysis published in April 2025 to develop a recommendation for 2029 seasonal PRMs. This study and its results are based on the 2024 member-submitted forecast for the resource mix and demand, using the 2023 LOLE study assumptions. Member-submitted demand forecast increased approximately 5% in summer and 6% in winter for planning year 2029.

ProbA Results

The 2025 ProbA study was performed on assumptions, and the accompanying methodology reflects methods used in SPP's LOLE studies, which have been thoroughly vetted through the SPP stakeholder process. Study improvements include additional weather years, seasonal forced outage modeling from the previous NERC probabilistic study, and incremental cold weather outages. More information on improvement and methodology can be found in SPP's LOLE study reports.

There was no observed unserved energy for years two and four of the base-case analysis for the SPP assessment area. This is most likely attributed to an increase of conventional thermal generations more than that of renewable resources and the delayed retirements of other thermal resources to meet the increasing projected demand needs. Since there are no observed load-loss events, additional reporting is not provided.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
***Provides the 2024 ProbA Results for Comparison**			

Demand

The SPP assessment area is a summer-peaking region and currently relies on the forecast submitted by the load responsible entities in the annual resource adequacy process. The 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023. Although actual demand is very dependent on weather conditions and typically includes the effects of interruptible loads, forecasted net internal demands are based on a 10-to-30-year average of summer weather, or 50/50 weather. Some SPP RTO members base their peak load forecasts on a 50% confidence level, as approved by their respective state commission(s). This means the actual weather on the peak summer day is expected to have a 50% likelihood of being hotter and a 50% likelihood of being cooler than the weather assumed in deriving the load forecast. SPP RTO members make economic assumptions in their individual forecasting methods as well consider the effects of non-controllable or dispatchable programs and resources within their area. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has seen in recent peak season.

Although SPP's energy projections for resource adequacy purposes differ from load interconnection process set forth in the SPP OATT, the SPP Assessment Area has received new load requests for data center, pipeline, oil and gas, irrigation and industrial load. While these loads represent above average load growth in areas, some of the load due to oil and gas exploration have decreased. Of current concern is the projected growth in the crypto load area and how much of that will turn into demand growth outside of the DR arena.

Demand-Side Management
SPP RTO members track dispatchable and controllable DR programs, which are used as peak load shaving programs. For resource adequacy purposes, the peak demand can be reduced by the impacts of the programs to determine an appropriate net peak demand for each member. SPP's tariff requires each Load Responsible Entity (LRE) to qualify and test their programs to prove they can meet and maintain the level of reduction submitted annually in the resource adequacy compliance window. SPP is constructing new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources
The SPP assessment area is forecasting ~70 MWs of DERs in the 5–10-year planning horizon. The impacts and assumptions may differ across the planning processes, for instance in some studies they may be used to reduce the load impacts whereas in other studies they may be modeled as a resource that has a high cost associated with it. SPP does not consider the impacts of BTM resource as a load reduction for purposes on resource adequacy compliance.

Generation
In general, SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026. There has been minimal retirement reported since the *2024 LTRA*, and a number of resources identified in 2024 as being set to retire are now being converted to new fuel, mostly coal to gas.

The *Expedited Resource Adequacy Study* process, approved by FERC in July 2025, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs. The program is yielding additional natural-gas-fired, solar, and battery resource projects in SPP's Tier 2 development queue. Nearly 8 GW of natural-gas-fired generator capacity, 2.2 GW nameplate in solar, and 1.8 GW nameplate in batteries have been added to SPP's Tier 2 queue since July and are not reflected in this year's LTRA. SPP anticipates the first interconnection agreements for *Expedited Resource Adequacy Study* projects will be signed in early 2026, which will qualify these resources for Tier 1 in NERC's reliability assessments and ProbA and count toward ARM.

Energy Storage
There are approximately 57,000 MWs of energy storage and hybrid resources in generator interconnection queues. There are about 50 MWs that are under contract by members across the SPP assessment area and 230 MW of nameplate capacity forecasted for the assessment timeframe. These resources are being modeled as generation in the planning assumptions both near and long term. Due to this limited amount of storage, limited operational impacts have been identified.

Capacity Transfers
Over the assessment time frame, SPP is forecasting, based on submitted member data, to be a net exporter of capacity. In the resource adequacy process, SPP only relies on the imports that have firm transmission service, which is ~2,000 MWs. SPP and ERCOT executed a Coordination Plan, which addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the Coordination Plan based on the latest discussions and business decisions related to resource priority.

Transmission
SPP's 2024 Integrated Transmission Plan (ITP) is the single largest portfolio, in terms of size and value, that SPP has proposed for construction in its 20-year history as a transmission PC. The approved plan includes 89 transmission upgrades needed to address increasing electricity consumption and changes in the region's generating fleet.

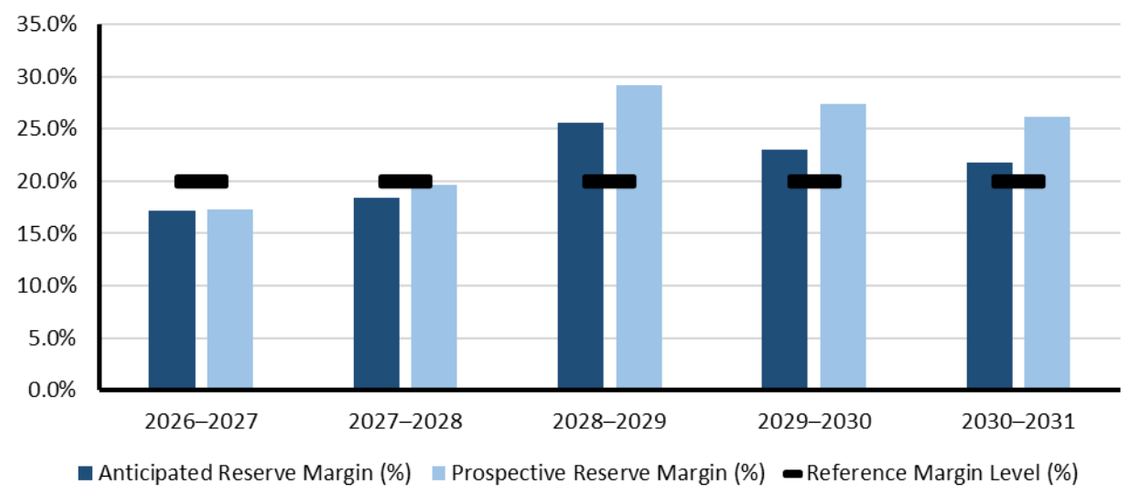


NPCC-Maritimes

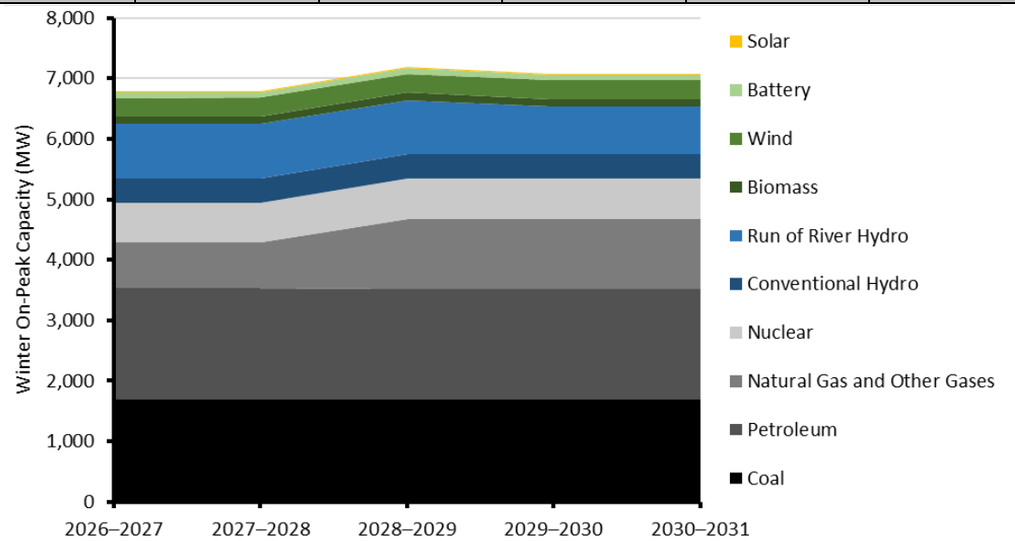
NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. State of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the BA for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the BA for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	6,107	6,157	6,194	6,231	6,292	6,346	6,380	6,493	6,579	6,669
Demand Response	264	283	290	291	290	291	290	291	290	290
Net Internal Demand	5,843	5,875	5,904	5,940	6,001	6,055	6,089	6,202	6,289	6,380
Additions: Tier 1	173	179	579	579	579	579	579	579	579	579
Additions: Tier 2	6	367	656	1,492	1,492	1,492	1,492	1,492	1,492	1,492
Additions: Tier 3	0	0	23	101	215	227	239	251	260	260
Net Firm Capacity Transfers	-32	75	145	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	6,673	6,780	6,838	6,727	6,727	6,727	6,621	6,621	6,596	6,707
Anticipated Reserve Margin (%)	17.2%	18.5%	25.6%	23.0%	21.7%	20.7%	18.2%	16.1%	14.1%	14.2%
Prospective Reserve Margin (%)	17.3%	19.6%	29.2%	27.4%	26.1%	25.0%	22.6%	20.3%	18.3%	18.3%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Maritimes Highlights

- Since the *2024 LTRA*, the overall resource outlook has diminished slightly with smaller peak capacity contributions from certain wind, hydro, and biomass resources through most of the planning period. Starting in 2026, winter peak demand forecasts for this assessment area have risen slightly from the previous year's projection through most years of the planning horizon; however, ARMs are currently projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,410	1,003	691
Petroleum	1,831	1,831	1,820	1,820	1,820
Natural Gas	757	757	1,157	1,157	1,157
Biomass	129	129	129	129	129
Solar	10	10	10	10	10
Wind	300	306	306	306	306
Conventional Hydro	395	395	395	395	395
Run of River Hydro	901	901	901	790	790
Nuclear	663	663	671	671	671
Other	98	98	89	89	89
Battery	99	99	99	99	99
Total MW	6,878	6,884	7,272	7,161	7,161
Total MW*	6,878	6,884	6,986	6,468	6,156
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The RML that is used for evaluating the New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM) sub-areas comprising the Maritimes area is 20% of firm load. The 20% criterion is not a mandated requirement. The ARM over the study period for the Maritimes area ranges between 14% to 26% during the winter period and between 74% to 90% during the summer period.

The ARM level during off-peak season for the Maritimes areas ranges between 74% to 90%. During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy needs and hence there are no constraints with converting the capacity to energy during these times.

The two BAs within the Maritimes area, as members of the NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

Energy Risk

During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy, needs and hence there are no constraints with converting the capacity to energy during these times.

The two Balancing Authorities within the Maritimes Area as members of the Northeast Power Coordinating Council (NPCC) jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual and seasonal ProbAs, which provide an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

ProbA

For the Maritimes area, the ProbA indicates elevated levels of unserved energy in February 2028 due to load growth projections and the characteristics of the resource mix during that period and with a few hours of risk in the shoulder months of December and January.

Annual metrics and requested enhancements including EUE heat maps, loss of load event analysis, and risk period visualizations for both 2027 and 2029 are included in the ProbA appendix.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	**5**	**15**	**7**
NEUE (ppm)	**0.17**	**0.52**	**0.25**
LOLH (hours/year)	**0.09**	**0.25**	**0.10**
*Results from the 2024 ProbA simulations			

Resource additions described in the Generation section below contribute to the improved EUE and LOLH metrics for study year 2029.

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period.

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.8% in summer and 1% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 6.6% during the 10-year assessment period for an average growth of 0.7% per year. Demand and energy forecasts have risen since the *2024 LTRA*, due in large part to rural-to-metropolitan population migration and the proliferation of heat pump technology in local areas previously heated by fossil fuels, primarily in the PEI region.

Demand-Side Management

Plans to develop up to 100 MW by 2030–2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 21 MW to 147 MW

while the annual amounts for winter peak demand reductions rise from 177 MW to 652 MW. [37] The total controllable and dispatchable DR increases from 328 MW to 337 MW in the summer period while increasing from 248 MW to 290 MW in the winter period.

Distributed Energy Resources

The DER installed capacity in NS is approximately 300 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar.

LTRA wind capacity for NB, NS, and PEI is de-rated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. Behind-the-meter (BTM) solar is assumed to have an ELCC of 0% during the winter period. The Maritimes area has shown embedded BTM solar PV projections of 204 MW in 2025 rising to 1,261 MW by 2035. These projects include distributed small-scale solar (mainly rooftop) projects that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of area's system peak which occurs either before sunrise or after sunset in the winter period.

Generation

NB plans to extend 28 MW diesel fired generator starting in 2025 and recently upgraded 277 MW of natural-gas-fueled resource completed in 2023. An anticipated replacement PPA contract, a long-term firm energy contract from neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

In New Brunswick, Tier 1 resources include 63 MW (installed capacity) of wind and 400 MW of combustion turbines. Tier 2 resources include 546 MW of wind resources and 72 MW of biomass.

In Nova Scotia, Tier 1 resources include wind projects with a total installed capacity of 635MW phased-in from 2025–2027. These projects include 306 MW as part of the provincial Rate Base Procurement program, a 168 MW wind project, a 12.5 MW wind project, and a 148 MW wind project under the Renewable to Retail tariffs. Tier 1 resources in NS also include a 150 MW battery (2025–2026). Tier 2 resources in NS include 600 MW of combustion turbines (2027–2029); a 150 MW conversion of a coal-fired unit to natural gas (2028); 459 MW conversion of coal-fire units to oil (2030); 250 MW of batteries (2027–2029); 262 MW of wind projects as part of the provincial Green Choice Program (2028–2029); and approximately 100 MW of solar independent power producer (IPP) projects (2026-2029) with an ELCC of 0%. Tier 3 resources in NS include new wind generation with a nameplate capacity of 1400 MW phased in from 2029-2034.

PEI has 30 MW installed capacity of tier 2 wind, 111 MW tier 3 wind, 140 MW of tier 3 Petroleum based generation and 10 MW of tier 3 batteries.

NB de-rates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI de-rate wind capacity to 18% and 17% respectively of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes Area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource (2025–2026) and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource (2027–2029). These grid scale projects will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 3 resource starting summer of 2028.

NB Power has not included any energy storage resources in the *2025 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest (REOI) for new renewable generation sources, including 200 MW wind, 15 MW solar, 5 MW tidal, and 50 MW 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources such as wind to provide additional flexibility to the system.

[37] Current and projected EE effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

Capacity Transfers
Probabilistic studies show that Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission
NS has multiple new transmission line projects compared to the 2025 LTRA, most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues
The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (de-rated), dual fuel oil/gas, tie benefits, and biomass with no one type feeding more than about 32% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges to resource during the assessment period.



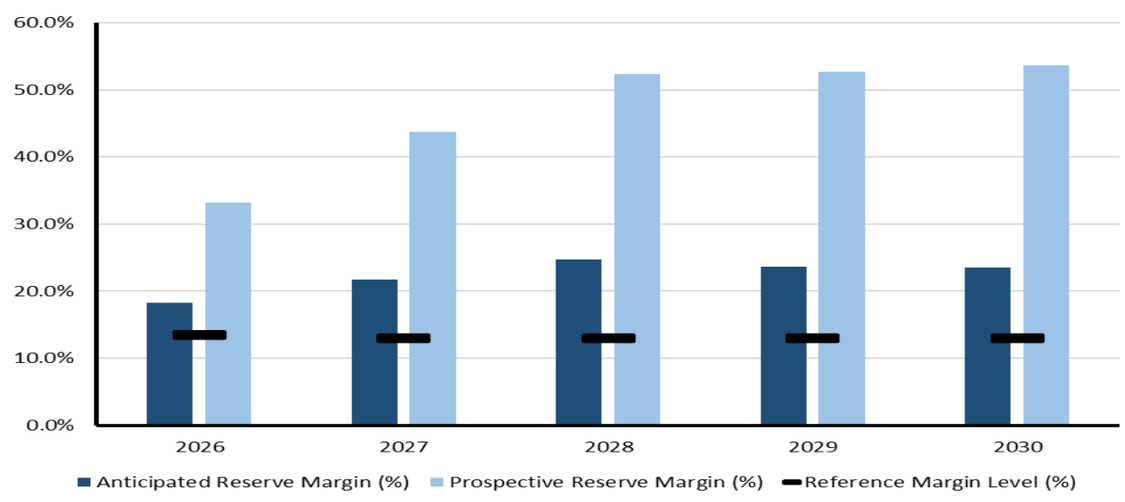
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

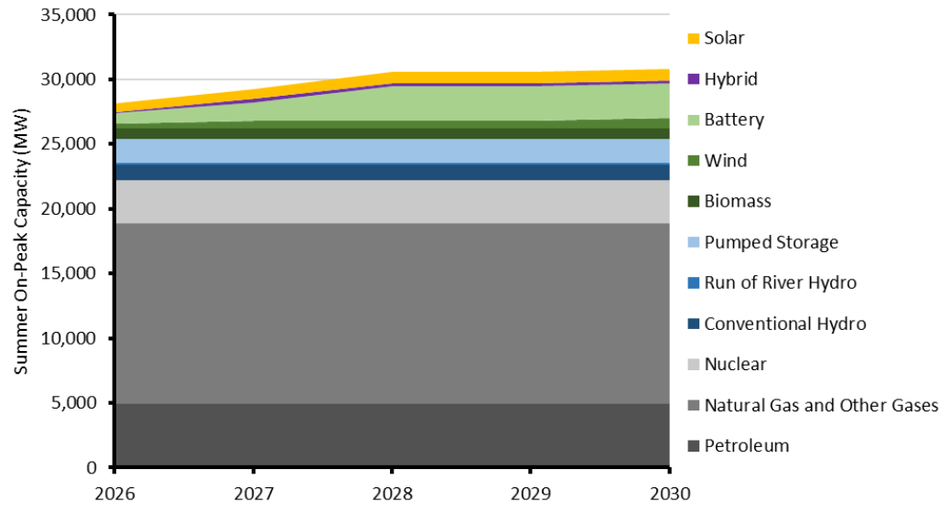
The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	24,877	24,945	25,124	25,347	25,557	25,821	26,123	26,486	26,897	27,331
Demand Response	623	544	544	544	544	544	544	544	544	544
Net Internal Demand	24,254	24,401	24,580	24,803	25,013	25,277	25,579	25,942	26,353	26,787
Additions: Tier 1	1,081	2,183	3,543	3,551	3,781	3,781	3,913	3,913	4,263	4,263
Additions: Tier 2	1,113	2,871	4,274	4,687	5,037	5,037	5,037	5,387	5,387	5,387
Additions: Tier 3	872	4,129	10,335	11,426	11,830	12,924	12,924	12,924	12,924	12,924
Net Firm Capacity Transfers	567	465	84	84	84	84	84	0	0	0
Existing-Certain and Net Firm Transfers	27,607	27,505	27,124	27,124	27,124	27,124	27,124	27,040	27,040	27,040
Anticipated Reserve Margin (%)	18.3%	21.7%	24.8%	23.7%	23.6%	22.3%	21.3%	19.3%	18.8%	16.9%
Prospective Reserve Margin (%)	33.2%	43.7%	52.3%	52.7%	53.7%	52.1%	50.8%	49.7%	48.7%	46.3%
Reference Margin Level (%)	13.4%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-New England Highlights

- New England is forecast to have sufficient seasonal ARMs needed to meet consumer demand for electric energy for the entire assessment period (2026–2035) and not require any Tier 2 resources.
- Ongoing developments of wind facilities and a new interregional tie with Canada (the New England Clean Energy Connect) as well as new technologies (such as longer-duration electricity storage) will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.
- The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[38]					
	2026	2027	2028	2029	2030
Petroleum	4,899	4,899	4,899	4,899	4,899
Natural Gas	13,939	13,939	13,939	13,939	13,939
Biomass	776	776	776	776	776
Solar	645	726	864	872	872
Wind	416	622	622	622	852
Conventional Hydro	1,165	1,165	1,165	1,165	1,165
Run of River Hydro	179	179	179	179	179
Pumped Storage	1,864	1,864	1,864	1,864	1,864
Nuclear	3,351	3,351	3,351	3,351	3,351
Hybrid	96	287	287	287	287
Battery	791	1,416	2,638	2,638	2,638
Total MW	28,121	29,223	30,584	30,591	30,821

- The winter ARMs do not fall below the annual RMLs for the entire assessment period.

[38] MW totals reflect existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

The winter ARMs do not fall below the annual RMLs for the entire assessment period. The winter ARMs range from a surplus high of 10,651 MW (66% ARM) in winter 2027–28 and then decrease each year to a surplus low of 4,522 MW (30% ARM) in winter 2035–36. The larger surpluses during winter (vs. summer) reflect the fact that New England is currently summer-peaking.

With the continued development of renewable and clean energy resources, the system will continue to emit lower air emissions.

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet NPCC's resource adequacy reliability criterion. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period (CCP). The latest ICR calculations result in an LTRA annual RML of 13% in 2026 and 2027, expressed in terms of the annual 50/50 peak demand forecast. For the years 2028 through 2035, ISO-NE continued to use the last available RML value of 13%.

Energy Risks (Including Non-Peak Hour Risk)

ISO-NE routinely prepares a 21-day energy assessment forecast and report. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the regional supply/demand balance is projected to be negative, then projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential electricity shortages should incentivize market participants to procure whatever is necessary (fuel) to follow future ISO dispatch orders. ISO-NE publishes its 21-day energy assessments every 2 weeks during spring, summer, and fall and then increases these publications to weekly (and/or daily if necessary) during the winter.

ISO-NE worked with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. The modeling results for the near-term PEAT assessments show for Summer 2027 that no energy shortfalls were observed in any of the events. One operating reserve shortfall was observed within a long-duration heat wave coincident with low wind scenario. For Winter 2027, a range of energy shortfall risks and associated probabilities were observed:

- The energy shortfall risk appears manageable over a 21-day period.
- These modeling results are consistent with the significant quantities of PV (BTM and utility scale), wind, and energy/electricity storage expected while experiencing minimal load growth.
- Operating risks may be mitigated by incremental imports from large inter-area transmission interconnects.

The modeling results for Summer 2032 also show that no energy shortfalls were observed in any of the hours of the 21-day period and only 1 hour of 30-minute reserve shortfall was observed. Baseline studies of Summer 2032 events indicate an energy shortfall risk similar to that of Summer 2027 events.

The modeling results for Winter 2032 show that the energy adequacy risk profile is dynamic and will be a function of the evolution of both supply and demand profiles. These results also reveal the range of energy shortfall risk under a variety of resource mix and demand assumptions. In terms of magnitude and probability, baseline studies of Winter 2032 events indicate an energy shortfall risk profile akin to that of Winter 2027 event studies.

Probabilistic Assessments (ProbA and Other Studies)

In conjunction with NPCC, ISO-NE conducts annual probabilistic resource adequacy assessments to identify regional capacity resource needs and to comply with NPCC/NERC reliability criterion/requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with neighboring systems will continue in support of the New England states' policy objectives of providing access to a greater diversity of clean energy resources and to comply with environmental regulations.

New England is a summer-peaking area. For the ProbA years, New England presents negligible risks in 2027 and very low risk in 2029 based on the ProbA results shown below.

NPCC New England Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	10.7	0.1	1.8
NEUE (ppm)	0.1	0.0	0.0
LOLH (hours per Year)	0.1	0.0	<0.1
* Provides the 2024 ProbA results for Comparison			

EUE Heat Map – 2029

For the 2029 summer season, the highest EUE risks are driven by high demand and low resources availability.

Month \ Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	10%	33%	24%	1%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	19%	5%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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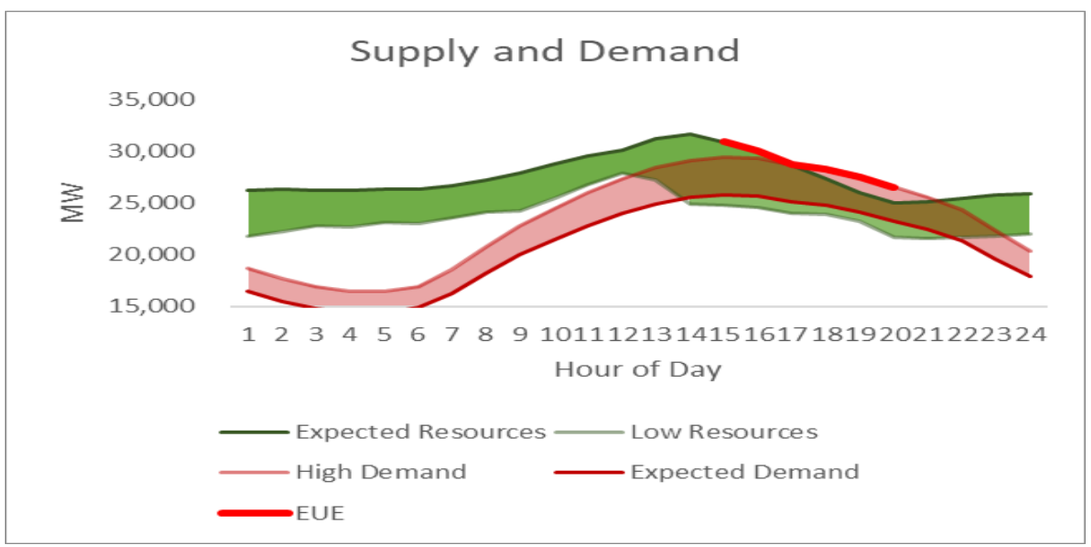
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

The figure below illustrates hourly demand and resource projections for the highest EUE day in 2029.



Demand

For its 2025 forecast, ISO-NE has updated its long-term forecast methodology to include hourly modeling of all load components, incorporation of climate-adjusted weather in forecast simulation, redefinition of gross load to reflect reconstitution for BTM solar PV (BTM PV) only, and an expanded forecast horizon that extends to 2045. This new base load forecast also already implicitly accounts for the load reduction from EE.

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,094 MW from 24,803 MW in 2025 to 26,897 MW in 2034. The corresponding net internal winter peak demand increases by 5,964 MW from 20,056 MW in 2025–26 to 26,020 in 2034–35. Net energy for load is forecast to grow by 13,403 GWh from 117,262 GWh in 2025 to 130,665 GWh in 2034. These peak growth projections have not changed significantly since the *2024 LTRA*. The energy growth projection has decreased as well since the *2024 LTRA*.

The higher winter peak growth rate due to anticipated electrification results in convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by that time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management (DR/DSM)/Distributed Energy Resources (DER)

For Summer 2026, ISO-NE forecasts 623 MW of controllable and dispatchable DR/DSM resources, which is projected to decrease to 544 MW by the summer of 2027. That value is then held constant through the rest of the assessment period.

For summer months, the results of the BTM PV forecast are incorporated into the ISO-NE gross demand forecast as estimated reductions in demand. In the summer of 2026, New England is expected to have 1,759 MW (5,093 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,942 MW (7,359 MW nameplate) by 2031. The winter capacity contribution for BTM PV resources is currently 7 MW (5,372 MW nameplate) in the winter of 2026–27 and increases to 521 MW (9,360 MW nameplate) in the winter of 2035–36.

In 2024, ISO-NE developed a new Planning Procedure 12 entitled *Data Collection for Distributed Energy Resources* to formalize and standardize data collection for DERs. Under this new planning procedure, distribution providers are responsible for providing installation-level data on DERs connected to their system (these DERs do not include DR, controllable loads, or other load modifiers). Additionally, transmission providers are responsible for providing data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits, this planning procedure will allow for proper accounting of the location, size, and type of DER, which will lead to more accurate operational and planning studies.

Generation

The two largest changes that will impact New England's generation fleet are the changes to the methodology for capacity accreditation and the development of a seasonal, prompt capacity market. Efforts are underway to change the timing and commitment horizons of capacity auctions to

seasonal/prompt in preparation for the evolving resource mix the Capacity Auction Reforms Key Project.

While ISO-NE does not expect any reliability impacts due to the retirement of any one single unit or station, the past and future retirements of dispatchable, fossil-fueled capacity, with on-site fuel inventories, as well as potential nuclear plant retirements, continue to exacerbate known winter reliability issues related to natural gas availability.

Energy Storage

New England has a total of 2,331 MW/2,110 MW (summer/winter rating) of energy storage capacity. Among the largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,864 MW / 1,861 MW (summer/winter rating) of quick-start 10-minute operating reserve capability, and with full reservoirs, can produce over 11,800 MWh of energy.

New England currently has 467 MW/249 MW (summer/winter rating) of electricity storage, including traditional battery storage along with integrated hybrid and co-located hybrid electricity storage.

As of April 1, 2025, there were 16,885 MW (summer ratings) of electricity storage devices (batteries, integrated-hybrid, and co-located-hybrid) that have submitted interconnection requests for installation over the next five years under the combined resource categories of Tier 1 at 2,658 MW, Tier 2 at 3,258 MW, and Tier 3 at 10,969 MW.

No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase/decrease from their 5-year projection.

Capacity Transfers (Reliance on Assistance)

New England is interconnected to three BAs: Québec, Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to meet the regional resource adequacy criterion while preventing over-reliance on such assistance. Assumed assistance from tie benefits ranges from 2,100 MW in 2026 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 567 MW in the summer of 2026 to 84 MW in the summer of 2028. There is one long-term firm import contract of 84 MW that extends from Summer 2028 through Summer 2032.

Within the *2025 LTRA* Prospective Resources (and Prospective Reserve Margin in the Demand, Resources, and Reserve Margins table), a summer and winter, energy-only contract is identified (i.e., expected imports). These numbers reflect the upcoming commercialization (in late 2025) of the New England Clean Energy Connect (NECEC), a new 1,200 MW tie line connecting Québec to Lewiston, Maine. An off-take 1,090 MW energy-only contract into Maine/New England has been executed. This import of 1,090 MW reflects the average hourly rate of the total annual energy in the contract.

In addition, there are no firm exports identified over the 10-year LTRA summer or winter assessment periods.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs that use inverter-based technology and changes to mandatory planning criteria promulgated by NERC and NPCC have driven the need for increasingly complex transmission assessments.

The future reliable and economic performance of the system is expected to continue to improve because of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of inverter-based technologies, and issues arising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. ISO-NE's longer-term transmission planning process was developed through coordination with NESCOE to create an additional path toward meeting these future system needs.

Reliability Issues

New England's power system is transitioning to a system with unprecedented projected demand growth and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE has been engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall power system reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected "in-service" dates for transmission system upgrades due to supply chain issues. In these cases, ISO-NE develops special operating plans to work around any issues caused by these commercialization delays.

New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. In winter, the interstate natural gas pipelines serving New England run full with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. In response, ISO-NE has been a key player at the national level in promoting electric/gas

communications/coordination, sharing of lessons learned, best practices, and more recently, through the performance of more detailed and in-depth deterministic and probabilistic energy assessments.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy/electricity—either through long-term energy/electricity storage solutions that can capture and store renewable power or through the use of flexible, dispatchable resources.

ISO-NE is actively working on numerous major projects as part of its energy transition while ensuring continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- Capacity Auction Reforms
- Operational Impacts of Extreme Weather Events
- Day-Ahead Ancillary Services Initiative
- 2024 Economic Study
- Extended-Term Transmission Planning Tariff Changes (aka Longer-Term Transmission Planning (LTTP) Tariff Changes)
- Longer-Term Transmission Studies
- Storage As Transmission Only Asset
- FERC Order No. 1920 Project
- FERC Order No. 2023 Project
- FERC Order No. 2222 Project

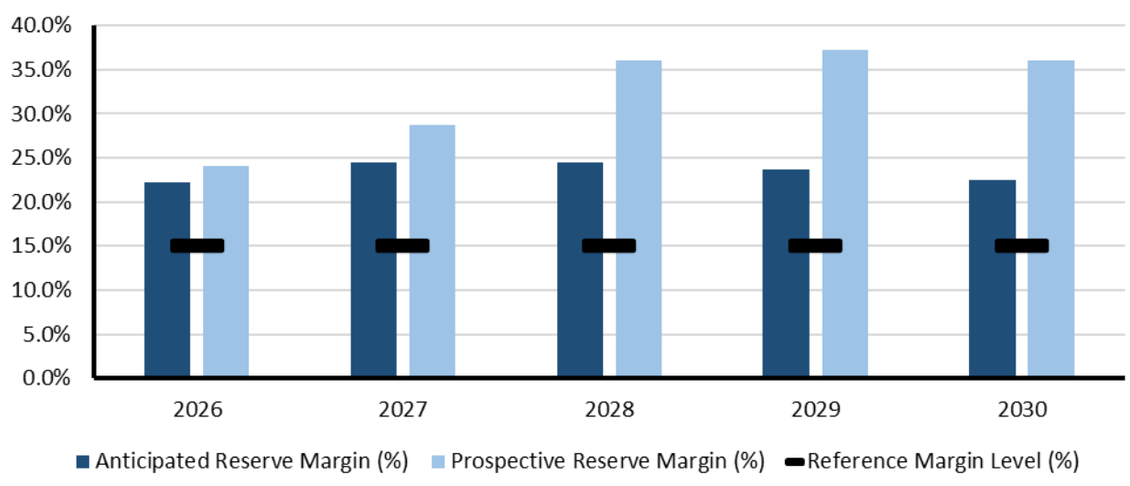


NPCC-New York

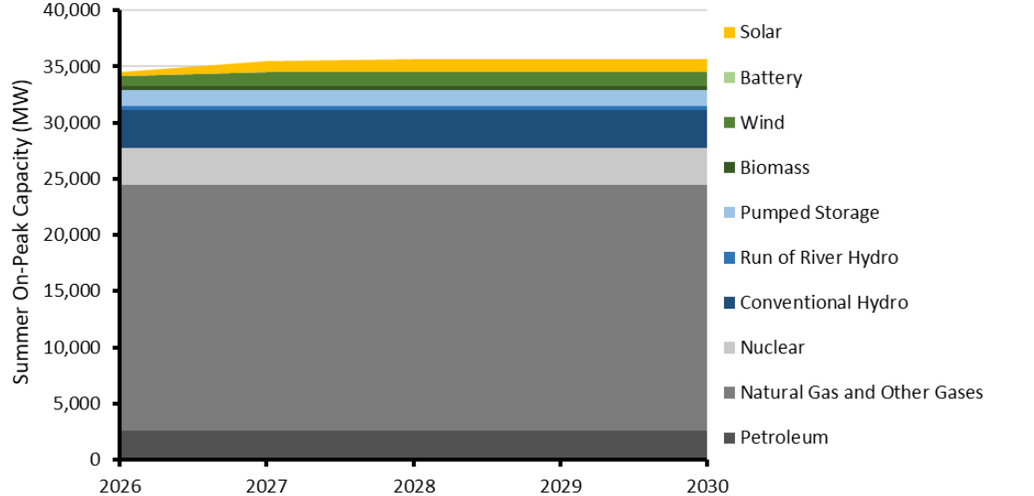
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	31,990	32,280	32,410	32,620	32,910	33,190	33,520	33,870	34,170	34,500
Demand Response	989	989	989	989	989	989	989	989	989	989
Net Internal Demand	31,001	31,291	31,421	31,631	31,921	32,201	32,531	32,881	33,181	33,511
Additions: Tier 1	532	1,509	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660
Additions: Tier 2	574	1,317	3,642	4,313	4,313	4,313	4,313	4,313	4,313	4,313
Additions: Tier 3	150	1,516	9,280	19,034	25,847	28,035	28,035	28,526	29,009	29,009
Net Firm Capacity Transfers	3,405	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486
Existing-Certain and Net Firm Transfers	37,368	37,449	37,450	37,450	37,450	36,995	36,995	36,995	36,995	36,995
Anticipated Reserve Margin (%)	22.3%	24.5%	24.5%	23.6%	22.5%	20.0%	18.8%	17.6%	16.5%	15.4%
Prospective Reserve Margin (%)	24.1%	28.7%	36.1%	37.3%	36.0%	33.4%	32.1%	30.7%	29.5%	28.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-New York Highlights

- Generator deactivations are outpacing new supply additions. Electrification programs and new large-load customers associated with economic development initiatives are pushing projected demand higher. Together, these forces are also narrowing reliability margins across New York and increasing the risk of future reliability needs.
- As public policy goals seek to decarbonize the grid, fossil-fired generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. EE and demand-side management (DSM) will continue to play a key role in reducing energy consumption, lowering costs, and mitigating environmental impacts.
- Some of the risks can be mitigated by repowering. Repowering aging power plants can lower emissions, meet rising consumer demand, and provide reliability benefits to the grid that are needed to integrate additional clean energy resources.
- New York is projected to become a winter-peaking electric system by the 2040s, driven primarily by electrification of space heating and transportation. On the coldest days, the availability of natural gas for power generation can be limited, and interruptions to natural gas supply will introduce further challenges for reliable electric grid operations.
- Driven by public policies, new supply, load, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection processes continue to evolve to balance developer flexibility with the need to manage the process to more stringent time frames. New processes have been implemented to accelerate the process while protecting grid reliability.
- The competitive wholesale electricity markets administered by NYISO support reliability while minimizing costs to consumers. Competitive wholesale markets are essential to a reliable, affordable, and cleaner grid of the future.
- NYISO's *2025 Quarter 3 Short-Term Assessment of Reliability* (STAR)[39] report identified short-term reliability needs in New York City and Long Island due to generation deactivations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	2,597	2,597	2,597	2,597	2,597
Natural Gas	21,858	21,858	21,858	21,858	21,858
Biomass	334	334	334	334	334
Solar	345	931	1,083	1,083	1,083
Wind	850	1,221	1,221	1,221	1,221
Geothermal	0	0	0	0	0
Conventional Hydro	3,324	3,324	3,324	3,324	3,324
Run of River Hydro	418	418	418	418	418
Pumped Storage	1,411	1,411	1,411	1,411	1,411
Nuclear	3,326	3,326	3,326	3,326	3,326
Hybrid	0	0	0	0	0
Other	0	0	0	0	0
Battery	32	52	52	52	52
Unknown	0	0	0	0	0
Total MW	34,495	35,472	35,623	35,623	35,623

[39] NYISO's *2025 Q3 STAR Report*: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf; Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; and Solutions Solicitation: https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's *2024 Reliability Needs Assessment*[40] found reliability margins decrease over time as load increases to the point that New York is nearly at the 0.1 even-days/year criteria by 2034.

NYISO also provides support to the New York State Reliability Council (NYSRC) in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC's resource adequacy criterion of "one day in 10 years." The current IRM for the 2025–2026 capability year is 24.4% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 24.4%. Additionally, NYISO performs an annual study to identify the Locational Minimum Installed Capacity Requirements (LCRs) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's Climate Leadership and Community Protection Act (CLCPA) decarbonization mandates to decarbonize span all major industries and are the main drivers of change to the electric system NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement, and certain combined-cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes, as well as supporting the calculation of the annual IRM, LCRs, and capacity accreditation. The new capacity accreditation market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The CAFs will reflect the marginal reliability contribution of the ICAP suppliers within each capacity accreditation resource class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

Additionally, every year, each Regional Entity (e.g., NPCC) provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2025 by the NPCC Regional Entity are shown below.

ProbA Results

New York is a summer-peaking area with negligible risks as shown in the low values in the following table of annual metrics.

[40] https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf

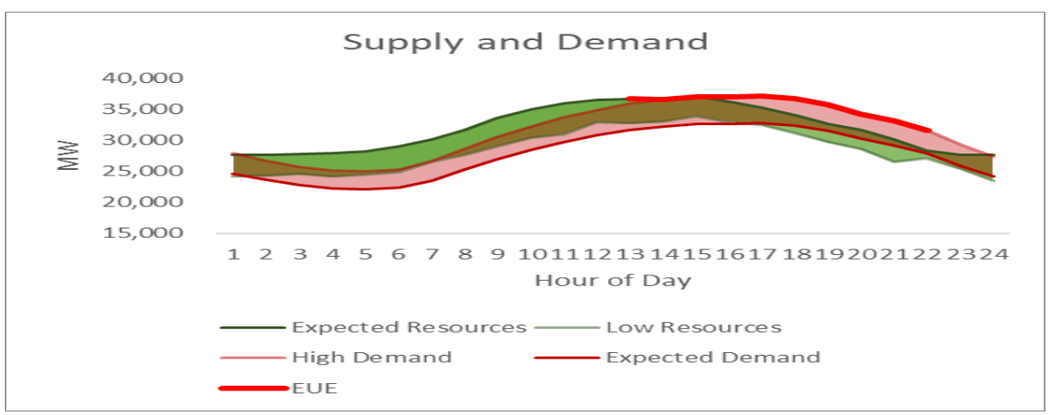
NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	1.909	0.466	12.478
NEUE (ppm)	0.012	0.003	0.078
LOLH (hours per Year)	0.011	0.002	0.035
* Provides the 2024 ProbA results for Comparison			

EUE Heat Maps – 2029

Negligible risk presented for Summer 2029, with occurrences clustered in July and August around hours 16 to 18.

Month \ Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	7%	24%	25%	7%	3%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	8%	16%	6%	1%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2029 are shown in the figure below.



Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the higher net demand levels from LFU compounded with a greater risk added due to the variability in resource contribution. The higher net demand LFU levels could be 10–13% higher than expected, which could strain the system as modeled in the ProbA.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as electric vehicle charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+1.0%) growth rates are similar to last year's forecast. Throughout the 30-year forecast period, baseline energy and seasonal peak demand increase significantly due to New York State electrification and decarbonization policies, principally the CLCPA. The baseline forecast includes significant electrification via conversion to electric heating and electric non-weather sensitive appliances, along with significant growth in EV adoption. In the early forecast years, large-load projects add significant growth to the annual energy and peak demand forecasts. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO has been working on developing market concepts to encourage the participation of flexible load, which participation will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy

policies. New York utilities are piloting several load management programs (e.g., smart electric vehicle charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

For the 2025 LTRA, the DR participation for the summer capability period has increased slightly from 1,294 MW to 1,487 MW. These values are nameplate and are derated for reserve margin calculations. For example, the 1,487 MW is derated to 989 MW. There are currently 433 MW of DR participating in ancillary services programs (not included in reserve margin calculations) and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

In 2024, NYISO implemented a plan to integrate DERs, including DR resources, into its markets. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single-participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

Significant new resource development will be required to achieve New York's energy targets under the CLCPA. According to the 2023–2042 System and Resource Outlook the total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply and meet policy requirements within the next 20 years.

Currently, NYISO's interconnection process[41] contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. The New York system relies on fossil-fuel, synchronous generation. ERSs usually provided to the system by synchronous fossil generation will remain necessary. As New York's public policies seek to decarbonize the grid, fossil-fuel, synchronous generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation.

On June 23, 2025,[42] New York's governor directed the New York Power Authority to develop and construct a zero-emission advanced nuclear power plant in upstate New York to support a reliable and affordable electric grid while providing the necessary zero-emission electricity to achieve a clean energy economy.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is preparing the implementation of a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resource models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with its neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO limits emergency assistance from neighboring systems by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighboring systems.

[41] https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx

[42] https://www.governor.ny.gov/news/governor-hochul-directs-new-york-power-authority-develop-zero-emission-advanced-nuclear-energy

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring systems. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring systems will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City, and
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new ac tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030
- Con Edison's proposed Brooklyn Clean Energy Hub project, including a new 345 kV load-serving substation with the goal of addressing local electric reliability needs in the boroughs of Brooklyn and Queens as well as the goal of serving as a point of interconnection for new clean-energy resources

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emission-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

NYISO's *2024 Reliability Needs Assessment*[43] (RNA) and subsequent analysis[44] identified very tight transmission security margins in New York City (Zone J) by 2034. The narrowing of the reliability margin continues to be a major concern. Most recently, NYISO's 2025 Quarter 3 STAR report[45] identified short-term reliability needs in New York City and Long Island due to generation deactivations.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

[43] https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf
[44] https://www.nyiso.com/documents/20142/51270164/CRP_KeyTopics_TPAS_050625.pdf
[45] NYISO's 2025 Q3 STAR Report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf and Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; Solutions Solicitation: https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf

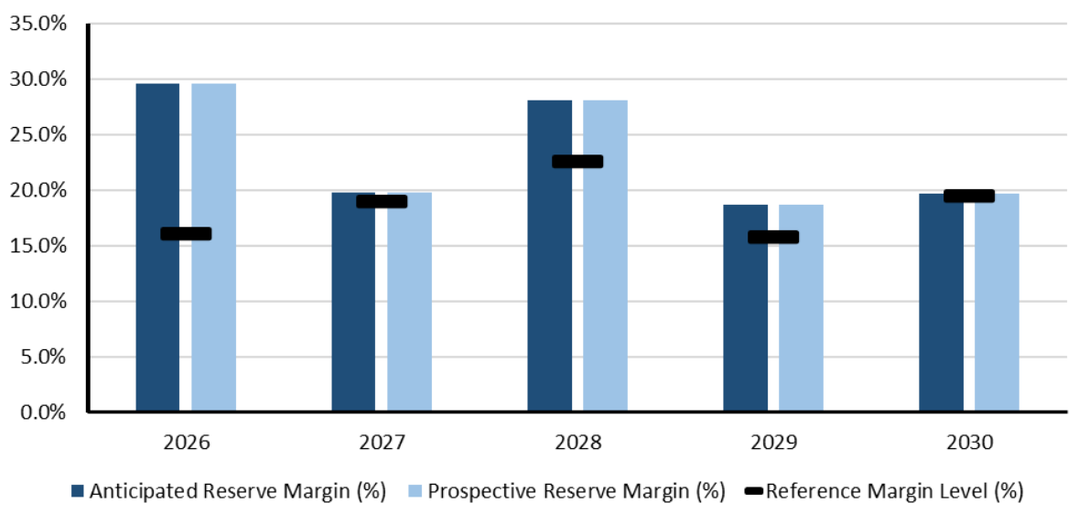


NPCC-Ontario

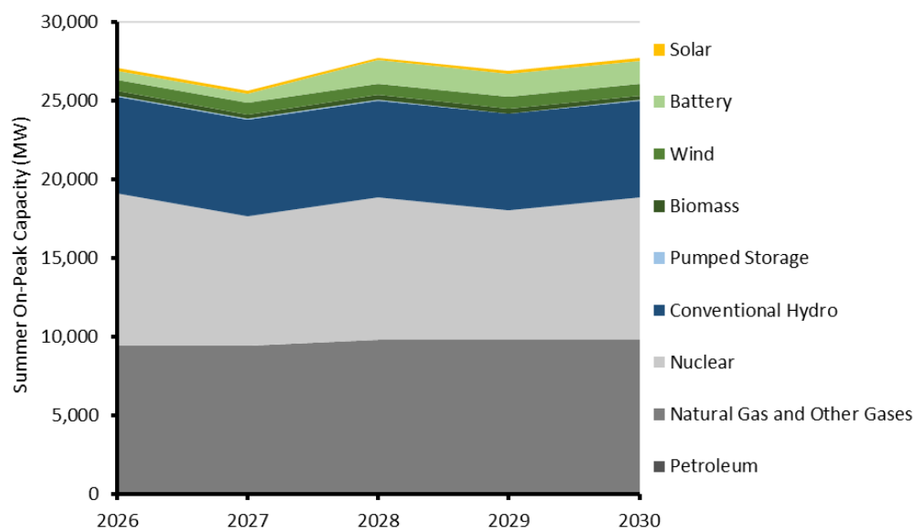
NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	23,403	24,023	24,514	25,587	26,443	26,927	27,747	28,621	29,202	29,974
Demand Response	2,046	1,998	2,090	2,092	2,093	2,095	2,096	2,098	2,099	2,101
Net Internal Demand	21,357	22,025	22,424	23,495	24,350	24,832	25,651	26,523	27,103	27,873
Additions: Tier 1	853	853	2,156	2,156	2,156	2,964	3,507	4,051	4,579	5,387
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	600	600	600	1,233	1,324	1,324
Net Firm Capacity Transfers	602	772	1,002	1,002	1,432	1,002	302	302	302	302
Existing-Certain and Net Firm Transfers	26,833	25,541	26,577	25,737	26,999	25,623	25,767	25,767	26,611	26,611
Anticipated Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Prospective Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Reference Margin Level (%)	16.1%	19.0%	22.6%	15.8%	19.5%	13.9%	14.7%	9.6%	14.3%	13.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Ontario Highlights

- Ontario's ARMs remain above the RML for the first five years of the 2025 LTRA outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030.
- Ontario's 2025 Annual Planning Outlook (APO) identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. Different to last year's LTRA, the IESO assumes generation resources are expected to be re-contracted (through the IESO's reacquisition mechanisms) after those contracts expire. This has improved the resource outlook for the IESO when compared to last year while aligning the methodology to forecast supply with the methodology used by other NERC assessment areas.
- For demand, Ontario projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. As a result, total internal demand is projected to grow by 31% over the next 10 years to nearly 30 GW by 2035.
- Ontario's generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. Ontario's planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed procurements to re-contract existing resources.
- Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW (installed capacity) of BESS to come on-line, with discharge durations of four hours.
- Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	3	3	3	3	3
Natural Gas	9,385	9,385	9,790	9,790	9,790
Biomass	299	304	310	310	310
Solar	150	150	150	150	150
Wind	724	725	728	732	732
Conventional Hydro	6,163	6,163	6,163	6,163	6,163
Pumped Storage	38	38	38	38	38
Nuclear	9,724	8,256	9,059	8,214	9,047
Battery	597	597	1,489	1,489	1,489
Total MW	27,084	25,622	27,731	26,891	27,723

NPCC-Ontario Assessment

Planning Reserve Margins

Ontario's ARMs remain above the RML for the first five years of the *2025 LTRA* outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030. No Tier 2 resources have been identified for this year's publication.

The IESO calculates Ontario's reserve margin annually using the GE MARS model and applies a more stringent reserve criterion than the NPCC standard of 0.1 days/year LOLE, incorporating additional reserves to manage risks associated with nuclear refurbishments and new nuclear builds. For example, over the LTRA outlook, the 2025 Annual Planning Outlook (APO) includes reserves of nearly 800 MW in some summers and nearly 1,100 MW in some winters to account for uncertainties in nuclear project timelines. If these additional reserves were excluded, Ontario would meet or exceed the RML in all years of the assessment. MARS inputs include resource availability, outages, refurbishment schedules, interface limits, and demand uncertainty. The model uses probabilistic simulations and Monte Carlo analysis for wind and solar and historical data for hydro and thermal units. The assessment evaluates system adequacy across all hours, not just peak periods.

For the *2025 LTRA*, the IESO applied NERC's definitions for Tier 1 and Tier 3 resources. The IESO's Resource Adequacy Framework (RAF) enables reacquisition of existing resources nearing contract expiry. It's important to distinguish between off-contract resources and those that have reached end of life or retired. Many existing Ontario resources remain operational and can be upgraded or re-contracted, with the RAF providing competitive mechanisms to secure capacity from these resources. The *2025 LTRA* assesses reliability independent of contractual status, unlike the 2025 APO, which aims to determine the resource adequacy needs in order to inform future reacquisitions of existing and new resources. As a result, the *2025 LTRA* outlook will differ from the 2025 APO, especially regarding off-contract resources that are likely to continue to be operational.

The RAF remains unchanged since the *2024 LTRA* and continues to guide the reacquisition of existing resources and the procurement of new capacity. The RAF supports a flexible, multi-pronged approach to resource adequacy, including capacity auctions, medium- and long-term procurements, and targeted programs for re-contracting or upgrading existing facilities and securing new resources.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Ontario conducts annual energy adequacy assessments using Energy Exemplar's Plexos software, which models the province's nodal transmission network and simulates dispatch under expected system conditions. These deterministic assessments evaluate energy sufficiency over a 20-plus-year horizon and are supplemented by sensitivity analyses to identify periods of heightened risk.

The 2025 APO identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. It should be reinforced that the APO presents an energy adequacy assessment used to inform future procurements, whereas the LTRA's purpose is to inform reliability of the system, where contractual end dates are not incorporated into the assessment

Shorter-term energy assessments are conducted quarterly through the Reliability Outlook (RO), which evaluates energy adequacy over an 18-month horizon. These assessments use probabilistic demand forecasts and outage data to identify seasonal and weekly risks. While the RO time frame is too short to secure new resources, the IESO uses operational tools such as capacity auctions, coordination with market participants on outage scheduling, and DR programs to mitigate risks.

Ontario's energy adequacy assessments do not assume economic imports or exports, reflecting a self-sufficiency planning approach. However, in practice, intertie capacity and capacity-sharing agreements (e.g., with Hydro-Québec) provide additional flexibility during periods of stress.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0.043	0.001	0.066
NEUE (ppm)	0.000	0.000	0.000
LOLH (hours per Year)	0.000	0.000	0.000
***Provides the 2024 ProbA Results for Comparison**			

Demand

Ontario's demand forecast is shaped by a combination of econometric modeling for the near-term and sectoral/end-use modeling for the long term. The 2025 APO projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. Growth projections in the *2024 LTRA* were 2.34% for summer and 2.75% for winter. Marginal increases in demand growth since the 2024 LTRA are attributed to data center growth and EV production. Incremental 2025 APO forecasted growth is driven by the following:

- Electrification of buildings, transportation, and industry
- Expansion of electric vehicle (EV) production and supply chains

- Rapid development of commercial data centers
- Population growth and household formation

Offsetting factors include increased EE, DSM programs, and a plateau in agricultural greenhouse expansion.

The 2025 APO forecasted Ontario to become a dual-peaking jurisdiction by 2030, with winter and summer peaks converging due to increased electrification of heating. The IESO's demand forecast incorporates updated assumptions on immigration, economic growth, and sector-specific developments, including hydrogen production, steel decarbonization, and data center expansion. Additional large loads in planning but not yet included in the forecast are assessed based on their development stage, funding, and likelihood of materialization.

Ontario anticipates significant changes in load behavior, including increased demand from building electrification, EV charging (shifting peaks), data centers, hydrogen electrolyzers, and large industrial loads. These trends introduce variability and new reliability challenges. The IESO conducts System Impact Assessments (SIA) for large loads, evaluating impacts such as voltage flicker and transient stability. Enhancements to the assessment process are underway. Additionally, annual regulation needs assessments project up to 110 MW of incremental regulation by 2035 to manage fluctuating loads, with procurement strategies in place to meet these needs.

Demand-Side Management

The IESO has implemented a capacity qualification process that applies performance-based derates to DR resources, ensuring more reliable capacity contributions. Since the *2024 LTRA*, the Peak Perks program has expanded to small businesses, helping the program deliver more than 152 MW of summer peak demand reduction in 2024, growing to over 200 MW in 2025. A new DR program targeting HVAC loads in the commercial and institutional sector is in development. These programs, as well as the Industrial Conservation Initiative (ICI), also contribute to peak demand reduction. A new electric demand side management (eDSM) framework spanning the next 12 years commenced with a $1.8 billion budget for years 2025–2027 targeting 4.6 TWh of energy savings and 900 MW of peak demand savings.

Distributed Energy Resources

Ontario's DER landscape includes both contracted embedded generation and uncontracted BTM resources. In 2024, contracted DERs totaled over 3,400 MW, with about 60% from solar, 20% from wind, and 15% from hydro and biomass. Uncontracted DERs contributed an estimated 2.7 TWh of energy.

DERs are integrated into planning through the Enabling Resources Program (ERP), which is developing participation models for standalone DERs, hybrid resources, and aggregations. The IESO is also advancing coordination protocols through the Transmission-Distribution Coordination Working Group (TDWG), which has proposed tools for real-time coordination and visibility. The group wrapped up work during Summer 2025 and has posted final reports on their findings.

DERs are considered in transmission planning as non-wires alternatives and are increasingly included in regional planning processes. The IESO's DER Potential Study and Local Generation Program aim to further integrate DERs into Ontario's RAF.

Generation

Ontario's generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. To maintain system reliability, the IESO continues to monitor key operational parameters such as primary frequency response and system inertia, both of which are currently sufficient but require reassessment as the resource mix evolves. Ramping needs can be provided by over 11,100 MW of natural gas generation with 600 MW able to be online and ramp within 20 minutes. Supply to the majority of Ontario's gas fleet is robust and supported by significant firm supply and transportation contracts. The IESO does not expect any material gas supply or delivery issues under extreme winter conditions. The day-ahead market, established through the IESO's Market Renewal's Program, allows for firm gas supply to be scheduled.

Deliverability testing is a core component of Ontario's long-term procurement process, ensuring that new resources can connect without causing congestion or reliability issues. For the IESO's second long-term procurement, testing will be expanded to include inverter-based resource screening for sub-synchronous control interactions.

Ontario has updated its Market Rules to align with IEEE 2800 and now requires synchrophasor data from generators and transmitters to improve situational awareness and IBR performance. The IESO is also conducting system-wide electromagnetic transient (EMT) studies and validating models for battery storage projects to proactively address sub-synchronous control interaction risks.

For Ontario's adequacy assessments, capacity contribution values for thermal resources are calculated using historical performance and probabilistic modeling. Wind and solar contributions are based on seasonal capacity factors, while hydroelectric values are derived from historical output. Energy storage contributions are based on a four-hour discharge duration.

Ontario's planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed medium-term procurements, which re-contracted existing resources for five-year terms. In addition to medium-term procurements, the IESO also maintains mechanisms such as Reliability Must Run agreements and capacity auctions to mitigate retirement risks. The IESO is currently conducting assessments for operating reserve and frequency response for the next 10 years, intended to be included in the 2026 APO.

Overall, Ontario's generation planning is increasingly focused on flexibility, resilience, and integration of emerging technologies, with a strong emphasis on ensuring deliverability, maintaining operability, and adapting to evolving reliability challenges.

Energy Storage

Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW of new BESS to come on-line, with discharge durations of four hours. These resources were secured through the Expedited Long-Term 1 (E-LT1) and LT1 procurements.

New storage projects may also participate in the second long-term procurement and long-lead time procurement, which aim to support system reliability during periods of high demand and low renewable output, particularly in the 2029–2035 time frame.

Energy storage resources are currently modeled as generators and loads at the same location, which presents operational challenges. The IESO is working to enhance its market tools and participation models through the ERP, which includes co-located and hybrid resource integration. Storage resources are also being incorporated into resource adequacy assessments using GE MARS software, which optimizes dispatch and accounts for energy reservoir size.

While operational experience with transmission-connected storage is still limited, the IESO is actively monitoring performance and refining planning assumptions. The integration of nearly 3 GW of new storage capacity over the next four years is expected to significantly improve Ontario's ability to manage variability and meet ramping needs.

Capacity Transfers

Ontario maintains robust intertie connections with neighboring jurisdictions, including Québec, New York, Michigan, Manitoba, and Minnesota. These interconnections play a critical role in supporting reliability, particularly during peak demand periods and resource shortfalls.

Two key capacity swap agreements with Hydro-Québec provide Ontario with firm summer capacity. The 2016 agreement allows for a 500 MW swap, while the 2024 agreement enables a 600 MW per year exchange over a seven-year period. These agreements are designed to be flexible, allowing Ontario to bank capacity and use it in future summers as needed.

Ontario's planning assessments assume self-sufficiency for the purpose of reserve margin calculations. However, in practice, these intertie agreements provide a valuable reliability backstop. The IESO coordinates closely with Hydro-Québec to align assumptions and ensure deliverability across the interties.

The refurbishment of Pickering NGS as well as new small modular reactors (SMR) scheduled to come on-line in the 2030s necessitated the review of flows across the province to maintain reliable operations. As a result, several new transmission projects have been proposed.

The IESO also participates in regional and interregional transmission planning processes, including NPCC area Transmission reviews and NERC planning assessments. These reviews ensure that Ontario's transmission system can support capacity transfers and maintain reliability under a range of scenarios.

Firm capacity transfers have appeared to increase in this LTRA publication compared to 2024 due to a review of NERCs definitions, allowing modeled and coordinated capacity to be treated as firm. This process aligns with the IESO's internal studies.

Transmission

Ontario is undertaking a significant expansion of its transmission system to support growing demand, resource integration, and system reliability. Key projects include the Waasigan Transmission Line, Etobicoke Greenway, and Flow East Towards Toronto (FETT) upgrade, which will collectively enhance capacity and resilience across the province. Additional reinforcements in London, Windsor-Essex, and northeastern Ontario address regional growth and industrial development. Voltage support devices, such as shunt reactors and STATCOMs, are being deployed to manage high voltages and support new transmission lines.

Transmission planning studies have identified constrained areas, particularly in the Greater Toronto Area (GTA), Essa (Barrie area), and eastern Ontario. These constraints are being addressed through the South and Central Ontario Bulk Plan and corridor studies to secure future transmission routes.

The IESO is also planning a new 500 kV double-circuit transmission line from Bowmanville to Toronto to support the connection of SMRs at Darlington NGS. This line is expected to be in service by the early 2030s.

To streamline transmission development and integrate Tier 2 resource deliverability insights, the IESO is designing a Transmitter Selection Framework (TSF) and enhancing its evaluation of non-wires alternatives (NWA). These initiatives aim to accelerate project delivery and improve coordination among stakeholders.

Reliability Issues

Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. The IESO is actively monitoring these trends and has published technical papers to better understand their implications. SIAs are conducted for large loads to evaluate impacts on voltage, stability, and power quality, with future enhancements planned to address sub-synchronous oscillation and ramp rate concerns.

Interdependencies with critical infrastructure sectors—such as natural gas, telecommunications, and transportation—are also being assessed. Ontario's gas supply is considered robust, with most generators located near the Dawn storage hub and supported by firm contracts. Dual-fuel capabilities of some generators and coordination protocols with gas pipeline operators further mitigate risks during extreme weather. The IESO's Market Renewal Program enhances gas-electric coordination through improved day-ahead scheduling.

Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments. Emerging technologies like battery storage and SMRs also present integration challenges. To address these, Ontario's planning processes prioritize flexibility, resilience, and proactive mitigation strategies, including outage planning that accounts for extreme weather scenarios.

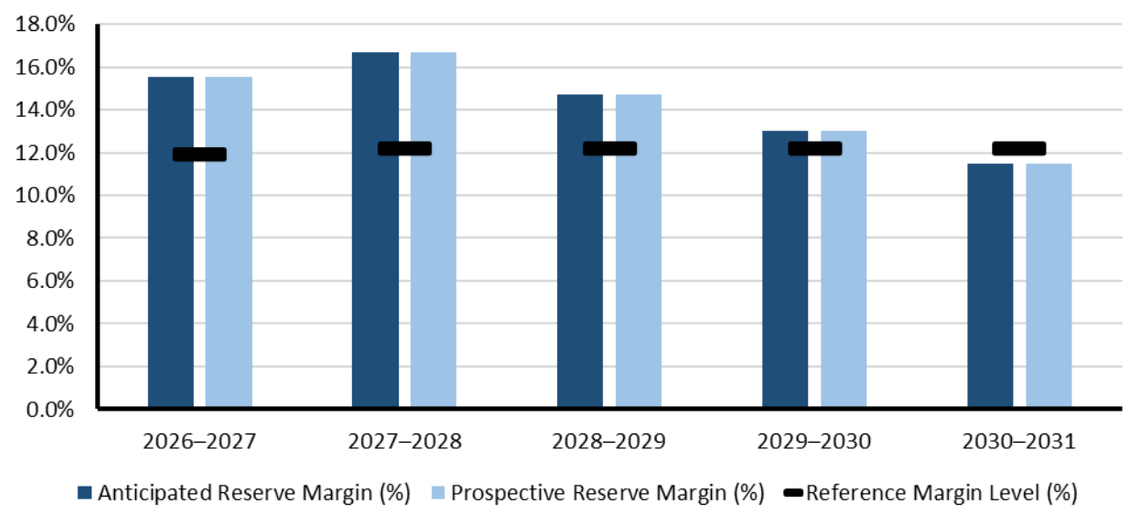


NPCC-Québec

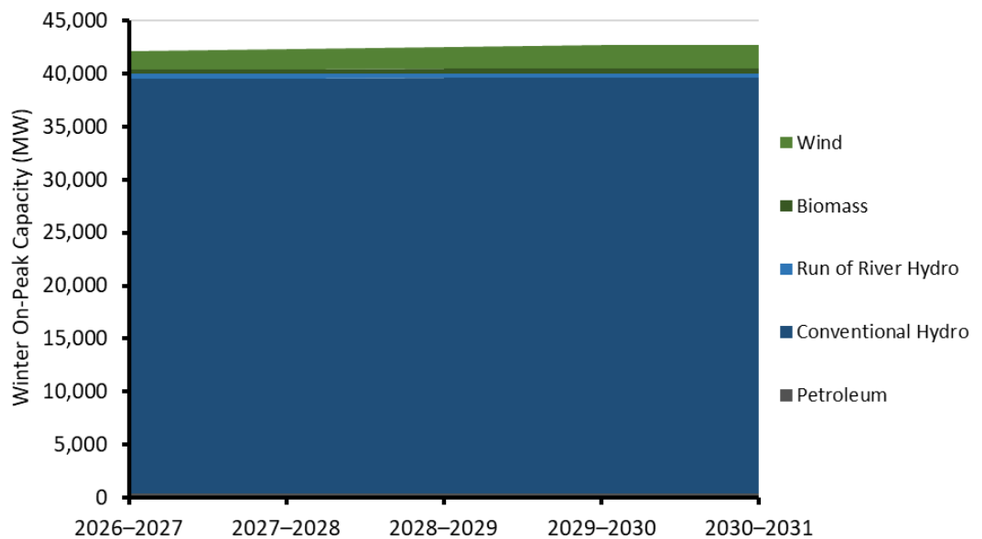
NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominantly hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	41,405	41,901	42,833	43,635	44,392	45,116	46,053	47,148	48,164	49,613
Demand Response	5,058	5,224	5,367	5,445	5,533	5,587	5,618	5,606	5,562	5,562
Net Internal Demand	36,347	36,677	37,465	38,191	38,859	39,529	40,435	41,542	42,602	44,051
Additions: Tier 1	412	566	710	891	891	891	891	891	891	891
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-145	455	455	455	600	0	0	0	0	0
Existing-Certain and Net Firm Transfers	41,591	42,231	42,269	42,272	42,421	41,825	41,830	41,834	41,838	41,842
Anticipated Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Prospective Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Reference Margin Level (%)	11.9%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Québec Highlights

- ARMs remain above the RML for the first four years of the assessment period.
- Over 4,000 MW of new wind installed capacity is expected to be in service by 2030, with additional wind projects in development.
- Hydro-Québec's Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and gas-fired generation. These projects are not included in Tier 1–3 categories in the present assessment due to their early development stage or ongoing stakeholder consultations but are expected to be incorporated gradually into future assessments.
- Major transmission projects, including the Appalaches–Maine (NECEC) and Hertel–New York (CHPE) interconnections, are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Petroleum	429	429	429	429	429
Biomass	405	405	405	405	405
Wind[46]	1,778	1,931	2,076	2,257	2,257
Conventional Hydro	39,091	39,129	39,167	39,170	39,175
Run of River Hydro	445	447	447	447	447
Total MW	42,148	42,342	42,524	42,708	42,712

[46] Expected at-peak capacity.

NPCC-Québec Assessment

Planning Reserve Margins
ARMs remain above the RML for the first five winters of the assessment period (2025–26 to 2029–30), supported by existing and anticipated capacity and firm imports. Margins fall below the RML starting in 2030–31 due to sustained demand growth from electrification. Several large-scale projects are under development but are not included in the reserve margin calculation due to their early-stage status. The RML is based on the 2024 NPCC Interim Review of Resource Adequacy and accounts for weather and economic uncertainty, generator outages, and DR constraints.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2024 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2024, and the 2024 Québec Interim Review of Resource Adequacy filed with the NPCC in December 2024.

Over 90% of Québec's installed capacity comes from large hydroelectric reservoirs, enabling flexible and reliable energy delivery. The system is designed to withstand multi-year droughts, with planning criteria requiring sufficient reserves to cover inflow deficits of 64 TWh over two years and 98 TWh over four years. No off-peak or seasonal energy risks have been identified.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, the EUE is 62.99 MWh with an expected LOLE of 0.106 hours per year.[47]

ProbA Summary of Results			
	2026*	**2027-2028**	**2029-2030**
EUE (MWh)	8.205	0.01	62.99
NEUE (ppm)	0.040	0.000	0.29
LOLH (hours per Year)	0.014	0.000	0.11
***Provides the 2024 ProbA Results for Comparison**			

Demand
Québec's demand forecast is driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Forecasts are developed using sector-level modeling and include high and low scenarios to reflect uncertainty.

Demand-Side Management
Hydro-Québec operates a broad portfolio of DR programs, including interruptible load contracts for industrial and commercial customers, and smart heating and dynamic pricing for residential users. These programs are expected to provide 5,600 MW of peak reduction by 2034–2035. Reported capacities reflect actual observed reductions during events. EE and conservation programs are integrated into demand forecasts.

Distributed Energy Resources
BTM solar PV is expected to reach 705 MW by 2035. However, due to Québec's winter-peaking profile, the on-peak contribution of DERs remains below 5 MW. No operational impacts are expected, and no DER aggregators are currently active in the area.

Generation
4,000 MW of wind installed capacity is under development or construction, including the Apuiat project (204 MW), three 400 MW phases of Des Neiges, and two procurement rounds totaling 2,700 MW. Hydro-Québec is also pursuing:

- Up to 2,000 MW from hydro unit upgrades;
- 5,000 MW of wind installed capacity through new community partnerships;
- 3,440 MW from Churchill Falls upgrades and the Gull Island project;
- 3,000 MW of solar installed capacity by 2035, including 300 MW of front-of-the-meter PV by 2029;
- Potential battery storage and natural gas generation.

Except for the 4,000 MW of wind capacity in construction, these projects are not included in the Tier 1–3 categories due to their early development stage or ongoing stakeholder consultations.

Energy Storage
No energy storage resources are currently planned for commissioning during the assessment period.

[47] 2025 Probabilistic Assessment results cover the period from March of the first year to February of the second year.

Capacity Transfers
Québec maintains firm seasonal capacity exchange agreements with Ontario (600 MW imports in winter, exports in summer). Québec has several firm capacity export agreements during the summer season.

Transmission
Hydro-Québec plans to add 5,000 km of new transmission lines and several major substations by 2035 to support regional development and renewable integration. Key projects include the following:

- NECEC (1,200 MW to Maine) – expected in service by December 2025
- CHPE (1,250 MW to New York) – expected in service by May 2026
- Three new 735 or 315 kV corridors in Québec
- Jean-Jacques-Archambault substation – planned for 2029

No long-term transmission constraints have been identified.

Reliability Issues
Large industrial loads are screened and approved by the Québec government and Hydro-Québec based on available supply. A moratorium is in place for new blockchain clients. The system's winter peak is primarily driven by residential heating, and industrial additions are not expected to significantly affect peak uncertainty. To mitigate the impact of rising demand, Hydro-Québec is expanding its DSM programs and studying multiple new generation projects. In addition, Québec's large hydro reservoirs provide strong protection against the impacts of drought. The system is planned to meet a regulatory energy reliability criterion requiring sufficient reserves to withstand inflow deficits of 64 TWh over two years and 98 TWh over four years.

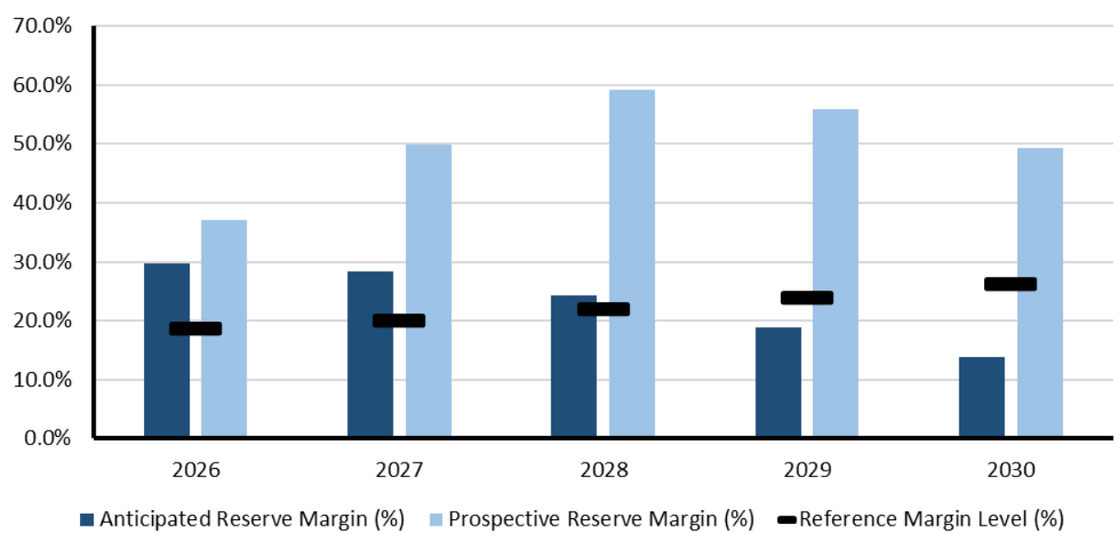


PJM

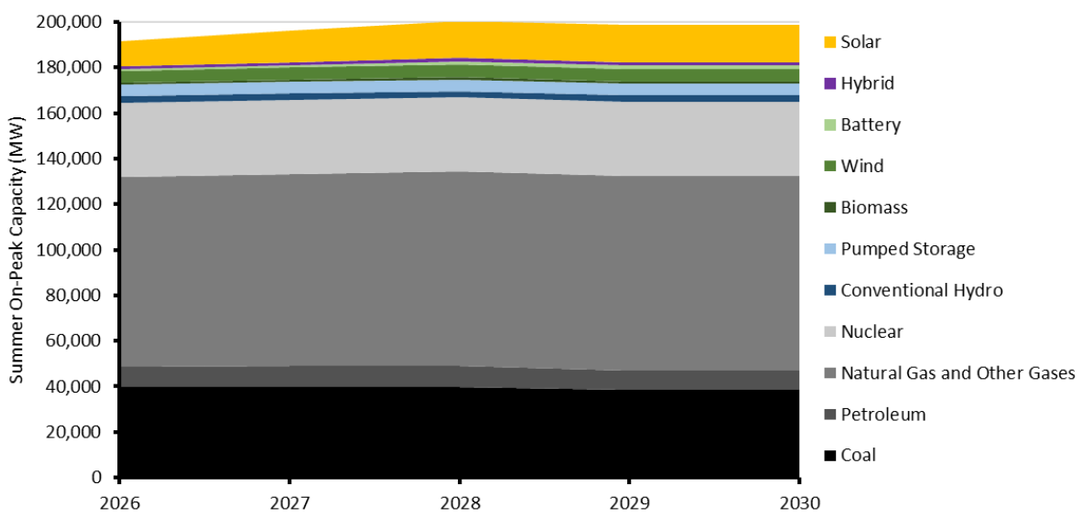
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and has an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	158,937	164,186	169,981	176,094	183,883	192,647	200,507	204,197	207,253	209,923
Demand Response	8,184	8,439	8,703	9,002	9,398	9,845	10,250	10,409	10,533	10,629
Net Internal Demand	150,753	155,747	161,278	167,092	174,485	182,802	190,257	193,788	196,720	199,294
Additions: Tier 1	5,861	10,177	14,521	14,709	14,709	14,709	14,709	14,709	14,709	14,709
Additions: Tier 2	12,410	38,519	65,315	71,119	75,116	75,290	77,655	77,655	77,655	77,655
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	3,840	3,818	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	189,693	189,644	186,005	184,030	184,030	184,030	184,030	184,030	184,030	184,030
Anticipated Reserve Margin (%)	29.7%	28.3%	24.3%	18.9%	13.9%	8.7%	4.5%	2.6%	1.0%	-0.3%
Prospective Reserve Margin (%)	37.0%	49.9%	59.1%	55.9%	49.3%	42.6%	27.7%	25.4%	23.5%	20.0%
Reference Margin Level (%)	18.6%	20.1%	21.9%	23.9%	26.3%	28.9%	30.8%	33.0%	35.1%	35.1%



Planning Reserve Margins



Existing and Tier 1 Resources

PJM Highlights

- Load forecasts have increased year over year due to data center and economic growth as well as increased electrification in the PJM footprint.
- Available generation capacity has decreased due to retirements and delays in new additions to the fleet.
- Based on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.
- PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid/minimize the need for emergency procedures.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	39,866	39,866	39,866	38,288	38,288
Coal*	39,866	37,738	27,448	28,002	26,464
Petroleum	8,952	9,163	9,163	8,766	8,766
Natural Gas	83,210	84,150	85,385	85,385	85,385
Natural Gas*	82,589	83,443	84,678	84,678	84,678
Biomass	857	907	907	907	907
Solar	11,282	13,616	16,141	16,328	16,328
Wind	5,251	5,496	5,622	5,622	5,622
Conventional Hydro	2,807	2,829	2,829	2,829	2,829
Pumped Storage	5,068	5,068	5,068	5,068	5,068
Nuclear	32,508	32,508	32,508	32,508	32,508
Hybrid	1,187	1,504	1,504	1,504	1,504
Battery	703	895	1,531	1,531	1,531
Total MW	191,712	196,002	200,524	198,737	198,737
Total MW*	191,091	193,166	187,399	187,743	186,205
***Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins
The PJM ARM falls below the Installed Reserve Requirement (RML) in 2029 when the ARM dips just below 19% as the RML reaches 24%.

- Accelerated retirements, driven by unit age and environmental public policy, of generators that provide necessary attributes needed to maintain reliability are outpacing new, mainly IBR additions. PJM received over 30 deactivation notifications totaling over 2 GW in 2024.
- Approximately 40% of new interconnection requests to the PJM grid are solar resources.

PJM faces an extreme and rapid tightening of supply and demand for capacity resources in the near term and needs additional resources to rapidly address its near-term reliability challenges.

PJM is in a transition year as the determination is based on the Reserve Requirement Study (RRS) and Effective Load Carrying Capability (ELCC) Study via PJM Manual 20A Resource Adequacy Analysis.[48]

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
Based on the load increase and generation decrease, PJM is projecting a potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.

PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid or minimize the need for such emergency procedures. The greatest risk is still during the summer peak period.

Probabilistic Assessments (NERC ProbA and Other Studies)
LOLH and EUE values for 2027 are 0.61 hours/year and 3,251 MWh/year, respectively, which are values consistent with PJM having a 2027 LOLE slightly worse than the 1 day in 10-year target. For 2029, the metrics significantly increase (LOLH = 9.97 hours/year and EUE = 67,581 MWh/year) due to significant forecasted peak load increases (i.e., more than 12,000 MW in summer and more than 14,000 MW in winter, driven by large load additions in the PJM footprint) and the changing resource portfolio mix (i.e., the retirement of thermal resources and the addition of wind, solar and storage, that do not provide an expected commensurate resource adequacy value when compared to the retired thermal resources).

In both studied years, large shares of the annual EUE and LOLH are concentrated in the winter months (especially January). In such winter days, the loss-of-load events identified by the model are driven by low temperatures, which result in high loads and the potential for high correlated outages from gas resources as well as poor performance from solar resources. These winter events tend to occur during both morning and evening peaks.

The smaller shares of EUE and LOLH observed in the summer period for 2027 and 2029 are driven by events in the evening (hours ending 19 and 20), during days with high temperature, high loads, and declining performance of BTM and front-of-the-meter solar resources, low performance of wind resources, and to a lesser extent by slightly worse performance of thermal resources.

The ProbA results differ from the LTRA results in that the ProbA models the following:

- Fewer additions: Resources that are identified as Tier 1 in the LTRA may not reach the in-service status on their targeted in-service date.
- More retirements: The current number of announced retirements does not reflect all the environmental policies that states in the PJM footprint are targeting for future years.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	538	3,251	67,580
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.11	0.61	9.97
* **Provides the 202**4 ProbA Results for Comparison			

Demand
The demand for electricity is growing at the fastest pace in years, primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing.

PJM expects its summer peak to climb by 55,779 MW to 209,923 MW in 2035, while winter peaks are expected to grow by 62,048 MW to reach 198,175 MW by winter 2034–35.

Sector models are a key part of the load forecast process, providing insights into why load trends are happening. Sector models also incorporate the independent assumptions on economic trends and

[48] https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.pdf

end-use adoption and efficiency. The PJM load forecast process considers three sectors: residential, commercial, and industrial. Each sector has its own set of models and inputs.

The load forecast is constructed using 24 hourly models for each zone. In each model, load is the dependent variable. In the history, we start with metered load and then re-constitute with load management addbacks, load drops associated with peak shaving programs, load related to load adjustments (where applicable), and distributed solar generation estimates.

PJM's projected load indicators in many instances have doubled from the *2024 LTRA* projections. For example, net energy for load growth for PJM is projected to average 4.8%, up from 2.3% in last year's projections, per year over the next 10-year period and 2.9% over the next 20 years. Total PJM energy is forecasted to be 1,328,045 GWh in 2035, a 10-year increase of 495,264 GWh, and reaches 1,482,068 GWh in 2045, a 20-year increase of 649,287 GWh. Annualized 10-year growth rates for individual zones range from 0.2% to 8.4% with a median of 1.6%.

Demand-Side Management

As in past years, DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during the summer peak season from 8,184 MW in 2026 to 10,629 MW in 2035. PJM's probabilistic resource adequacy modeling accounts for observed DR availability variations by season and hour.

Distributed Energy Resources

PJM expects 4,810 MW of solar DERs at the time of summer peak demand in 2030 and 5,165 MW in 2035. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

PJM also expects 3,652 MW of contributions from plug-in EVs to load at the time of summer peak demand in 2030 and 8,250 MW in 2035, with additional contributions from distributed battery storage ranging from 300–900 MW over the same five-year period.

The net effect of DERs is included in the load forecast as the models utilize recent historical data, which implicitly include DERs.

Generation

PJM added 560 MW of new on-peak generation capacity since the 2024 LTRA. The new projects include one wind project at 24.5 MW and 19 solar projects totaling 535.5 MW. An additional 70 MW in capacity was connecting in late 2025.

Substituting thermal resources (coal, natural gas, and oil) with renewable generation (wind, solar, storage, and hybrid resources) may get significantly more challenging as the energy transition progresses and flexible thermal resources are still needed to maintain resource adequacy at one-in 10 LOLE.

Maintaining an adequate level of generation resources with the right operational and physical characteristics is essential for PJM's ability to serve consumer demand through the energy transition. The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. Today, thermal resources supply ERSs. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability.

Increasing levels of intermittent resources create significant variability and uncertainty to be managed by flexible resources. If the gas fleet of today remains as is, or decreases due to regulatory pressures, but additional storage resources do not get built at pace, immense pressure will be placed on natural gas to supply the ramping needs for the system. Changes to market mechanisms will be evaluated to ensure that adequate resources are incentivized to help PJM manage increasing system uncertainty and volatility.

For example, in 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative, which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. PJM projects that the initiatives will boost Tier 1 resources by an additional 8.3 GW in summer periods and 3.4 GW in winter periods from the original *2025 LTRA* data submittal.

Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original *2025 LTRA* data submittal and 4.1 GW in winter capacity. These net increases factor resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

However, many of these projects continue to be slowed or stopped by factors that extend beyond PJM and affect multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges, and financing.

PJM uses some differing capacity assumptions between the LTRA and ProbA. The LTRA counts more resource additions, mainly new solar and gas combined-cycle units, which may not actually become operational. In contrast, the ProbA is more conservative, excluding some Tier 1 resources that might not reach the in-service date as planned. Additionally, the LTRA only accounts for officially announced

retirements, while the ProbA also factors in potential retirements caused by state environmental policies, particularly affecting coal resources projected to retire by 2029.

As of June 2025, all generation capacity resources, with the exception of VERs, that are committed in PJM's Reliability Pricing Model or committed in a PJM Fixed Resource Requirement Plan shall be subject to operational testing initiated by PJM up to two times in each of the summer and winter seasons during the relevant delivery year. (Seasons are defined as: summer (May–October) and winter (November–April). Generation operational tests will be unannounced tests. The tests are being conducted to verify that generating resources can reliably operate when needed.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy DOE national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

There is approximately 162 GWs of solar, wind, battery and hybrid in the PJM interconnection queue requesting capacity injection rights. Hybrid resources make up approximately 20 GWs and standalone storage makes up approximately 40 GWs.

To address the limited-duration issue, some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Currently new storage is dispatched similar to other generators in economic order. No more specific operation has been considered due to the small penetration. Many older batteries are used for regulation.

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if its transfers were dropped to zero.

Transmission

Beginning in 2023, PJM began to identify trends encompassing large load increases in specific areas, driven primarily by the construction of new data centers, and these were incorporated in PJM's 2024 RTEP cycle analyses for five-year (2029) and eight-year (2032) study year models. The large load increases are driving heavier, increased regional transfers and the consequent need for significant system reinforcement. PJM's load forecasting process incorporates methods by which it solicits and applies large load adjustments by transmission zone. Electrification itself is the process of converting conventional end-use load that uses fossil fuels (e.g., gas stoves and oil-burning furnaces) to use electricity instead, as well as the increased use of EVs. This is having a significant impact on the magnitude of the load forecast and load shape. Notably, additional electric heating will narrow the gap between summer and winter peaks.

Most transmission additions are related to local load deliverability problems and not new generation enhancement in Tier 2. Each generator is responsible for transmission enhancements associated with its interconnection and network enhancements if necessary. PJM does not use Tier 3 resources.

PJM's analysis of 2029 and 2032 summer, winter and light load conditions identified 8,520 thermal and voltage criteria flowgate violations across PJM, of which 1,609 were ineligible from competitive windows. The 6,911 remaining violations were addressed in 2024 RTEP Proposal Window No. 1

The large number of violations observed in the 2024 RTEP were driven by heavy west-to-east transmission interface flows caused by large load increases in the Dominion zone and in eastern PJM: 10 GW and 15 GW load increase for 2029 and 2032 between the load forecasts used for the 2022 and 2024 RTEP study cycles, respectively. The significant load growth is attributed primarily to data centers, electrification, and electric vehicle developments.

From PJM's 2024 RTEP Proposal Window No. 1 (July–September 2024), 94 competitive proposals to solve the 6,911 NERC reliability criteria violations identified in the RTEP 2029 model year analysis as well as those identified in the 2032 model year requiring long-lead-time transmission solutions. The PJM board approved $5.9 billion worth of regional and local projects to address the reliability criteria violations.

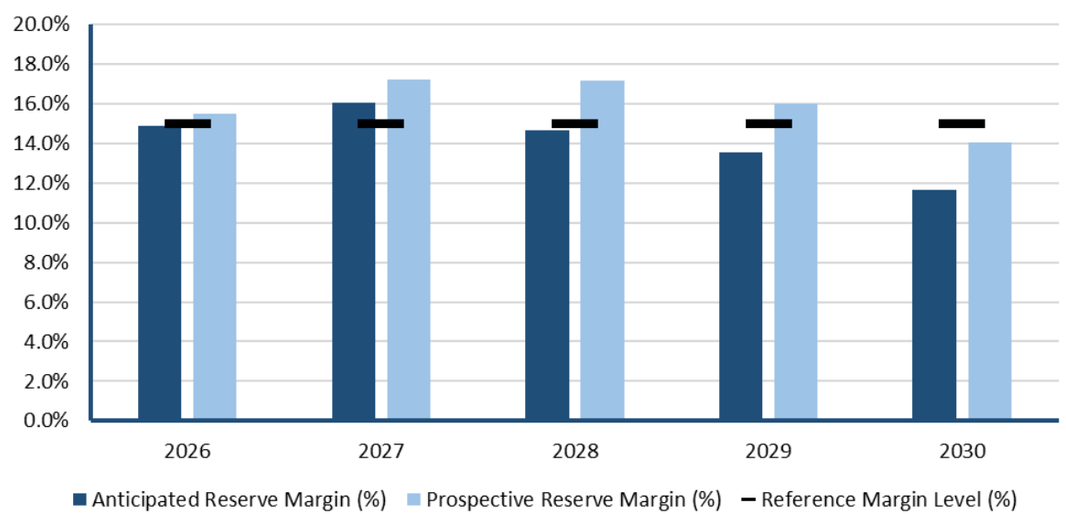


SERC-Central

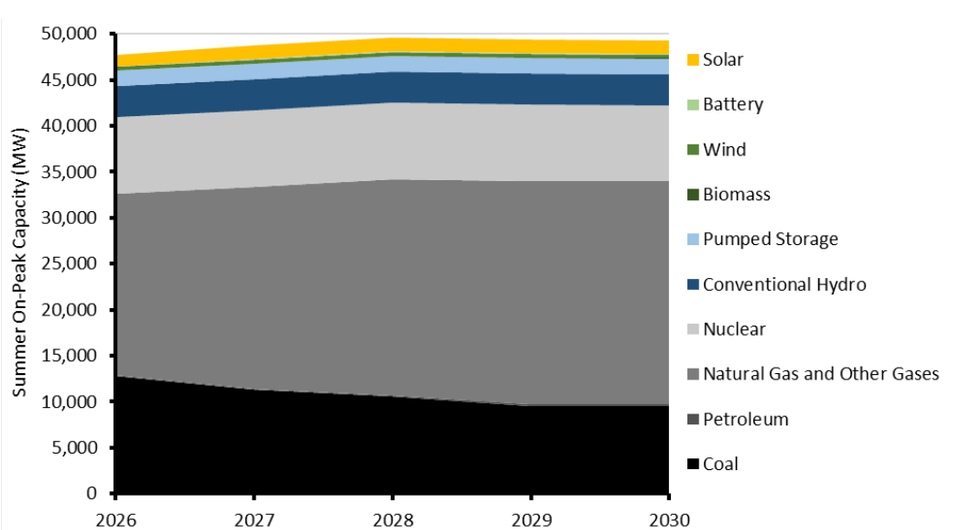
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	43,066	43,512	44,298	44,616	45,280	45,975	46,034	46,168	46,412	46,619
Demand Response	2,818	3,047	3,287	3,356	3,364	3,377	3,392	3,367	3,323	3,301
Net Internal Demand	40,248	40,465	41,011	41,260	41,916	42,598	42,642	42,801	43,089	43,317
Additions: Tier 1	518	492	4,567	5,435	5,435	5,435	5,435	5,435	5,435	5,735
Additions: Tier 2	20	245	837	837	837	837	837	837	837	837
Additions: Tier 3	178	234	300	362	743	795	2,107	3,293	5,539	5,591
Net Firm Capacity Transfers	460	391	-288	-287	-287	-221	-221	-220	-220	-157
Existing-Certain and Net Firm Transfers	47,859	47,438	45,895	44,503	43,474	43,382	43,448	42,484	42,485	41,414
Anticipated Reserve Margin (%)	19.1%	20.8%	19.7%	18.5%	16.5%	14.8%	12.4%	12.0%	8.7%	9.0%
Prospective Reserve Margin (%)	19.7%	22.0%	22.3%	21.1%	19.0%	17.3%	14.9%	14.5%	11.2%	11.5%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Central Highlights

- SERC-Central is projected to remain above its RML through 2030. The ProbA shows no loss of load over the 2027 and 2029 study years.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	12,782	11,308	10,595	9,565	9,565
Coal*	**12,782**	**11,308**	**9,944**	**8,914**	**8,914**
Petroleum	128	128	128	128	128
Natural Gas	19,706	21,956	23,483	24,341	24,249
Natural Gas*	**19,279**	**21,529**	**22,585**	**23,443**	**23,443**
Biomass	37	37	37	37	37
Solar	1,181	1,408	1,445	1,455	1,455
Wind	370	370	370	370	370
Conventional Hydro	3,405	3,405	3,405	3,405	3,405
Pumped Storage	1,247	1,247	1,247	1,247	1,247
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	100	135	135	135	135
Total MW	47,236	48,274	49,124	48,963	48,871
Total MW*	**47,256**	**48,267**	**47,996**	**47,835**	**47,835**
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins

PRMs are crucial for ensuring the reliability and adequacy of electric transmission systems in the Central assessment area, with various entities employing different methodologies and targets. The concept of LOLE, often aiming for a standard of one day in 10 years (0.1 LOLE annually), is a critical metric used to establish these targets.

Several entities establish reserve margin levels based on resource adequacy study results. For instance, one entity sets target reserve margins at 29% in winter and 23% in summer, determined using a 1-in-10 LOLE study, a change from its previous economic reserve margin approach, which resulted in lower targets. Another entity performs a reserve margin study using the Astrapé Strategic Energy and Risk Valuation Model (SERVM) to establish summer (18%) and winter (25%) planning targets, balancing seasonal risk and cost, which also aligns with a 1-in-10-year expected probability of a loss-of-load event. Another entity uses the NERC/SERC-accepted 15% reserve margin for predominantly thermal systems, which is generally consistent with a one-day-in-10-year loss of load. Methodologies for determining these margins often involve probabilistic modeling using extensive weather data (e.g., 40 years of weather data with Astrapé SERVM) and simulations of hourly forced outages, load, market availability, and renewable resources. Key drivers of risk often include extreme weather, low renewable generation, forced outages, and limited import capability.

Since the *2024 LTRA*, some significant changes have occurred or are underway. One entity recently updated its minimum reserve margin constraints from economic reserve margin targets to a resource adequacy standard of one day in 10 years LOLE. This entity also conducted a LOLE study that incorporated improvements such as enhanced peak demand modeling and additional sensitivities, including temperature-dependent outage probabilities. Load forecasting is also updated annually to meet NERC MOD-32 requirements, aiming to maintain reserve margins at minimal cost while balancing risk, reliability, environmental responsibility, and flexibility.

Currently, most entities' ARMs are not expected to fall below their RMLs. However, challenges stemming from load growth and increased load sensitivity to weather, particularly in winter, have led to a reduction in reserve margin levels over the next 10 years for some. To address potential shortfalls and future needs, resource additions are being planned, including solar facilities, natural gas combined-cycle units, and battery storage. Utilities also account for uncertainty and variability in assumptions through quantitative scenario modeling and probabilistic weighting of key assumptions. The results of energy risk assessments are used to establish or confirm PRM targets based on simulations and scenario analyses, which account for variability in load, weather, and unit outages to ensure system reliability.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Energy risk assessments are an evolving aspect of grid reliability planning, moving beyond traditional peak-demand analyses to encompass all potential hours of the year, including non-peak periods in the Central subregion. These comprehensive assessments are vital due to the increasing variability and uncertainty in system demand and resource mix. Utilities employ a range of methods for these assessments, often including detailed LOLE studies that simulate hourly conditions over a 10-year horizon, incorporating extensive historical weather data and system flexibility. Some entities adopt a holistic, year-round planning approach that integrates scenario-based reserve margin analysis and robust fuel inventory management to handle supply and demand uncertainties. Probabilistic modeling is commonly used, leveraging extensive weather data (e.g., 40 years of weather data), and simulating hourly forced outages, load, market availability, and renewable resources to identify risks across a wide range of conditions.

Key drivers of risk examined in these assessments include extreme weather (both highly unexpected demand impacts and unseasonable conditions), low renewable generation, forced outages, and limited import capability. Other factors considered are low water conditions, fuel availability (such as natural gas pipelines and their interdependencies), resource outages, transmission constraints, common mode failures, correlated and dependent outages (derations), ramping limitations, and flexibility requirements. The results of these energy risk assessments are directly used to establish or confirm PRM targets, which are designed to account for variability in load, weather, and unit outages to ensure overall system reliability. These assessments also emphasize the importance of a balanced and diversified generation portfolio to reduce dependency on single sources and to hedge against supply disruptions. Furthermore, they support detailed operational planning, such as maintaining higher reserve margins during shoulder months to mitigate risks from maintenance outages and unpredictable weather, and implementing fuel security measures like firm transportation contracts and fuel inventory targets. Ultimately, the outcomes of energy assessments inform and guide a broad spectrum of strategic, operational, and planning decisions, ensuring that utilities can build robust, adaptive plans to provide consistent and reliable service despite external uncertainties and the evolving conditions of the electricity system.

ProbA Results

In the SERC model, based on data and assumptions, SERC-Central does not show any loss of load risk for 2027 nor 2029 for any of the 5375 cases. The annual metrics are shown below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0.10	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*Provides the 2024 ProbA Results for Comparison			

However, the study shows overall reliance on imports from neighboring areas with the potential of insufficient local generation to meet the demand. The month of April in particular shows the risk of low hydro generation, which can coincide with planned maintenance outages. The summer load forecast is expected to grow by 1,005 MW and winter load forecast is expected to grow by 781 MW from 2027 to 2029. At the same time, there is an expected retirement of approximately coal generation in 2028, leading to tighter margins. Close to 2,600 MW of gas generation is expected to be added in the same period. Based on the ProbA, overall margins get tighter in 2029.

Demand growth, planned generator retirements, fuel diversity and reliance on imports contribute to growing energy risks. SERC and the SERC Central entities will need to continue to monitor the resource adequacy studies.

Demand

Utilities in the Central assessment area employ comprehensive and evolving methodologies to project future energy and demand needs, crucial for accurate system planning. Load forecasts are regularly updated, typically every one to two years, drawing heavily on historical data including hourly load profiles, economic indicators, demographic trends, and weather patterns. Many entities utilize econometric or regression-based models to capture the relationship between energy usage and variables like temperature, population, and housing. To account for uncertainty and variability, some utilities develop multiple forecast scenarios, employing historical weather extremes or probabilistic modeling to capture a range of potential outcomes. Forecasts also integrate emerging factors such as DERs, EVs, and end-use efficiency trends. Advanced modeling techniques include shaping system forecasts with hourly load profiles by customer class and DER type, with adjustments for anticipated industrial or commercial growth. Load forecast uncertainty (LFU) is managed through both quantitative scenario modeling and probabilistic weighting of key assumptions. Forecasts beyond a 10-year horizon, while highly uncertain, provide insights into potential long-term drivers such as the addition of data centers and large commercial/industrial loads, which can substantially increase demand and are often modeled as sensitivities in reliability studies. Electrification trends, particularly in home heating, contribute to increased winter peak sensitivity, and transportation electrification is expected to become a more significant driver beyond the 10-year horizon. While climate change and extreme weather impacts often are not pronounced in probabilistic load models, some models are refined to reflect more frequent cold weather patterns, and load impacts are often addressed through scenario planning rather than directly embedded in long-range forecasts.

Demand-Side Management

DR and other DSM programs vary significantly across utilities in the Central assessment area, playing a role in managing demand and enhancing system flexibility. Some entities model their DR programs as dispatchable supply-side resources, meaning their contribution is not reflected as load reductions in forecasts, with available capacity often estimated based on historical performance and being highly weather-dependent. Plans are in place for significant expansion of DR capacity over the next five years by some entities. Specific programs include legacy Interruptible Power, the newer PowerFlex offering greater flexibility in response times, and the relaunched dispatchable voltage regulation (DVR) program, which provides enhanced credits for both emergency and capacity events. Conservation voltage reduction (CVR) is employed as a 24/7 energy-efficiency tool, and Peak Rewards is an aggregator-based DR program for large commercial and industrial customers. Capacity from these programs is estimated based on historical reactivity to voltage changes and forecasted load, with some having specific use limitations, such as 400 event hours per year for DVR. While some smaller entities in Central report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, other entities are actively growing this resource class, particularly for DR and peak load management. These aggregator-based programs are included in IRP inputs and modeled through semi-annually updated Power Supply Plan processes. The development and refinement of these programs help utilities ensure consistent and reliable service by balancing supply and demand, especially during critical periods.

Distributed Energy Resources

DERs, primarily solar PV, are generally incorporated into net load forecasts by most entities within the Central assessment area, though the specific methodologies and extent of integration vary. Some entities utilize historical data and national laboratory research to integrate distributed generation and EVs into their peak demand and energy forecasts. For example, one entity projects solar PV to reach approximately 1% of summer peak demand by 2028, with total DER capacity anticipated to be 153 MW by 2032. Another entity, which incorporates both BTM and front-of-meter DERs, forecasts solar PV penetration to grow from 250 MW by 2029 to 350 MW by 2034. They model BTM resources using irradiance-based hourly shapes and treat program-based solar as a fixed energy supply with simulated profiles. Future DER growth is projected using adoption curves based on economic payback periods and market trends, also accounting for local self-generation programs that allow up to 5% of annual energy needs.

However, some entities in the region either do not currently utilize or separately account for DERs due to minimal penetration or a lack of utility-sponsored programs. One entity has implemented a

cap on DER penetration at 10% of peak demand, expecting to reach this limit within five years, and models DERs at 80% of capacity during system peaks. IBRs, which include many DERs, are subject to rigorous modeling and verification processes, including fault ride-through testing, oscillation monitoring, and the enforcement of a minimum short-circuit ratio (SCR) to maintain system reliability.

The contribution of DER aggregators is currently limited but is actively expanding in the assessment area, with select entities integrating them into planning and demand-side management strategies. These aggregator-based programs are included in the entity's Integrated Resource Plan (IRP) inputs and are modeled through its semi-annually updated Power Supply Plan process. While some smaller entities report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, others with minimal DER participation do not account for them separately in resource planning. The capacity from DER aggregators, where applicable, is generally reflected as part of DR resources and modeled as dispatchable or embedded in the net load forecast, depending on the entity. Overall, the assessment area sees a proactive effort by leading entities to grow this resource class for DR and peak load management as the energy landscape evolves.

Generation

Utilities in the Central assessment area are actively engaged in managing their generation portfolios, which are undergoing significant transformation, primarily driven by the integration of IBRs and a focus on flexible, dispatchable capacity. Planning entities have mechanisms to prevent the retirement of reliability-critical units, such as state laws mandating replacement with dispatchable capacity or ensuring replacement generation is established before retirement. Reliability and reserve margin studies are used to assess the impacts of retirements. One entity maintains its plan to retire a 297 MW coal-fired unit in 2027 due to economic and environmental factors, though the timing is under reassessment. There have been no changes to confirmed or unconfirmed retirements since the *2024 LTRA*, with entities projecting no new retirements.

Changing Resource Mix and Operational Considerations: Entities are addressing potential operational issues stemming from this evolving resource mix, particularly due to the increased penetration of solar, BESS, natural gas, and hydro resources. For instance, one entity is retiring a 297 MW coal-fired unit and adding approximately 240 MW of utility-owned solar, a 645 MW natural gas combined-cycle (NGCC) unit, and a 125 MW battery storage facility to enhance system ramping flexibility and absorb more intermittent generation. While annual stability assessments generally show no transmission stability issues, some entities have observed operational challenges related to IBR controls, tuning, and power oscillations. To mitigate these, advanced testing and commissioning processes for new IBRs are being implemented, including a "burn-in" period, and utilities require utility-scale solar resources to operate on automatic generation control (AGC) and allow for automated, proportional output reductions during surplus conditions. Planning activities regularly assess system inertia with IBRs, finding no critical issues related to low system inertia so far.

Addressing Net Demand Ramping Needs: Planners are proactively ensuring sufficient flexible resources are available for long-term net demand ramping needs. Some entities maintain a diverse mix of flexible, dispatchable resources with no planned thermal asset retirements, ensuring adequate inertia and system stability. One larger entity is preparing for the potential integration of up to 11,000 MW of solar over the next 15 years. Proactive measures include replacing 1,400 MW of aging combustion turbines (CTs) with 1,500 MW of modern Frame-type CTs, refurbishing older peakers, and planning for at least 500 MW of new aeroderivative CTs to support flexibility. Exploration of **long-duration energy storage technologies**, such as pumped hydro, gravity-based systems, and flow batteries, is also underway to provide future flexibility. A contractual ability to curtail solar output during times of low demand and high solar output, particularly in spring, serves as a backup measure.

Capacity Contribution Values for Various Resources: Capacity contribution values for different generation types vary based on resource characteristics and available data:

- **Thermal resources** typically use historical performance data, with planned additions relying on vendor guarantees. Forced outage rates for thermal units are generally not reflected in the reported values.
- **VERs** like wind and solar utilize seasonal or monthly net dependable capacity (NDC) values based on historical performance or modeled solar irradiance at peak times. For example, one entity uses 84% of nameplate capacity for solar in summer and 0% in winter, while another uses a 50% confidence level for monthly wind and solar contributions, accounting for inverter risk.
- **Energy storage** contributions vary by duration and reliability benefit; one entity assigns 93% for 8-hour storage and 85% for 4-hour storage, considering 4-hour duration sufficient for reliability.
- **Hydroelectric resources** are evaluated using historical seasonal performance. Most methodologies have remained consistent since the previous LTRA, with updates primarily to assumptions for loads, outages, and transmission imports. Probabilistic modeling, such as ELCC, is used to ensure resource adequacy.

IBR Performance and Reliability: Entities are actively addressing reliability risks from IBRs through various study requirements and operational protocols. Some require EMT models as part of the interconnection study process. Rigorous modeling and validation practices are implemented, including mandating PSSE and PSCAD models for interconnection, enforcing quality control, and evaluating harmonic distortion. A key focus is on inverter control systems that prevent momentary cessation and ensure inverters remain on-line during voltage and frequency excursions. While no

protection schemes or ancillary service needs have explicitly emerged, increased regulation demand has been observed with growing IBR penetration. AGC capability is being mandated for all new utility-scale solar facilities, and legacy plants are being retrofitted to allow system-wide output reductions for flexibility during surplus generation events. The primary challenges with IBRs relate to system stability and control rather than resource adequacy.

Generator Retirements

Natural Gas Fuel Supply Risk: Natural gas fuel supply risk is mitigated through various strategies, including **on-site fuel oil backup** at key generation sites and contingency-based studies simulating pipeline disruptions. One entity estimates that approximately **87% of its gas-fired winter peak capacity will have firm gas transportation or fuel oil backup** within the next five years. Following a 2022 winter event, reliability improvements were implemented by an affected pipeline operator. Strategies also include 100% storage-backed firm transportation for combined cycle units, diverse procurement and scheduling, and embedding fuels personnel in system operations for real-time communication with pipeline operators during contingency events. Long-term planning considers natural gas infrastructure limitations when evaluating new generation resource locations, ensuring fuel supply adequacy and construction timelines.

Energy Storage

Energy storage, primarily BESS, is being added to the system and is expected to contribute to reliability and flexibility. Expected uses include economic operation, reliability enhancements, peak shaving, and frequency response. The capacity contribution of energy storage is factored in based on its supply duration, with entities considering different minimum durations (e.g., 4-hour or 8-hour discharge capability). One entity is adding a 125 MW battery storage facility. These resources are incorporated into long-term planning through IRPs and power supply processes.

Capacity Transfers

The Central assessment area is proactively managing capacity transfers and ensuring transmission adequacy through a variety of studies, strategic investments, and coordinated efforts to maintain system reliability amidst an evolving resource mix and load growth.

The assessment area's ability to transfer capacity is continuously evaluated and is evolving:

- **Evaluation Methods:** Transfer capabilities are assessed through biennial resource adequacy studies that account for firm contracts and probabilistic delivery expectations, showing a positive contribution from increased firm contractual capacity to overall reliability. Seasonal assessments are also conducted to identify surplus transfer capacity across different times of the year, allowing for more accurate planning of bidirectional flows and optimizing the scheduling and delivery of transfers.
- **Observed Impacts and Trends:** One entity has seen an increased reliance on external generation resources, with over 6% of its firm capacity sourced from outside its immediate footprint, driven by fossil unit retirements, load growth, and shifts in its generation portfolio. While no significant changes in power flow patterns have been identified overall, the ongoing transition in the resource mix, along with planned retirements and new additions, is anticipated to influence future transfer scheduling, surplus availability, and bi-directional flow characteristics.
- **Coordinated Efforts:** Entities are implementing various coordination efforts to ensure reliable capacity transfers:
- **Seasonal Capacity Transfer Studies** analyze how different system conditions (e.g., summer and winter peaks, shoulder months) impact import/export capabilities.
  - A transfer monitoring process tracks firm capacity from external generators, ensuring their reliable availability during peak conditions.
  - Coordination with neighboring balancing authorities is undertaken to secure contractual commitments and physical transfer capability.
  - Some entities embed transfer analysis into their long-term planning documents (e.g., IRPs) to evaluate how future firm transfers impact transmission constraints and local reliability.

Transmission

Entities in Central are maintaining transmission adequacy, with significant projects and planning processes in place to address limitations and ensure reliability.

- **Major Transmission Projects:** The assessment area is undertaking numerous projects to support reliability and accommodate changing load and generation patterns. These include the following:
  - **New Line Construction:** Approximately 158 miles of new 345 kV lines and 18 miles of 161 kV lines, along with new 56 MVA 161/69 kV stations
  - **Substation Construction and Expansion:** Three new 345/161 kV stations and one new 161 kV switching station
  - **Transformer Additions/Upgrades:** Various upgrades to 345/161 kV and 161/69 kV transformers to increase capacity
  - **Line Rebuilds and Voltage Conversions:** Over 227 miles of 161 kV lines are being rebuilt, and nearly 20 miles of 69 kV lines are being converted to 161 kV

- **Voltage and Stability Projects:** Installation of a 60 MVAR capacitor bank (by 2025) and planned Statcoms to address voltage reliability
- **Regional Reinforcements:** Projects like a new 161 kV Line and Apalachia Area Improvements are critical to mitigate thermal overload, voltage collapse, and support native load reliability

- **Identified Transmission Limitations:** Planning studies have identified constraints often associated with transformer overloads, line loading issues, or high-voltage conditions.
- **Mitigation Planning and Actions:** To address identified limitations, utilities employ the following:
  - **Operating Guides and Real-Time Controls:** Providing generation dispatch limits or specific switching actions for constrained locations
  - **Infrastructure Expansion:** Planning multiple long-term system reinforcements
  - **Congestion Management Processes:** Using system operator tools and protocols to re-dispatch generation or adjust flows
  - **Annual Transmission Assessments:** Identifying and addressing long-term transmission constraints, including new service requests and interconnections
- **Changes to Transmission Planning Processes:** Since the 2024 LTRA, several enhancements are being implemented or considered:
  - Expanding the biennial Long-Range Plan to incorporate power transfers and extreme weather events
  - Updating generator interconnection and affected system procedures to comply with FERC Order No. 2023, with one entity transitioning to a cluster study approach (transitional cluster in 2025, full cluster in January 2026) to streamline interconnection requests and reduce backlogs
  - Evaluating multi-value projects through resource and capacity assessments to proactively address long-term transmission needs

Reliability Issues

The Central assessment area is actively managing and addressing a range of reliability issues stemming from evolving system conditions, including changes in resource mix, load growth, and extreme weather.

- **Reduced Reserve Margins and Challenges from Load Growth:** Entities in the SERC-Central region are confronting challenges due to load growth and an increased sensitivity of load to weather, especially in winter, which has resulted in a reduction in reserve margin levels over the next 10 years. While some entities anticipate their ARMs will not fall below their RMLs, one entity projects that without replacement resources, its reserve margin would fall below its target range due to a unit retirement in 2027, necessitating further resource additions for increasing economic development load beyond 2027. Underlying reliability issues include increasing winter peak demand sensitivity to weather and the potential for new large commercial loads. To address this, resource additions are being planned, and some entities are shifting their minimum reserve margin constraints to a resource adequacy standard of one day in 10 years LOLE, moving away from prior economic reserve margin targets that resulted in lower targets. Large industrial or commercial load additions, such as data centers and manufacturing centers, are actively monitored as they can introduce reliability risks due to short lead times and uncertain scalability, potentially challenging load forecasting and transmission development.
- **Operational Issues and System Stability with the Changing Resource Mix, Particularly IBRs:** The assessment area is actively addressing potential operational issues stemming from the increasing integration of IBRs like solar and BESS. Some entities have experienced operational challenges related to IBR controls, tuning, and power oscillations, including instances where solar generation contributed to over-generation events. While annual stability assessments have not yet identified transmission stability issues or critical issues related to low system inertia, increased regulation demand has been observed with growing IBR penetration. To manage these risks, entities are implementing proactive measures such as advanced testing and commissioning processes for new IBRs, requiring them to demonstrate stable performance. New utility-scale solar facilities are being mandated to operate on AGC, and legacy plants are being retrofitted for system-wide output reductions to provide flexibility during surplus generation events. The primary challenges related to inverter risks in the assessment area are system stability and control, rather than resource adequacy.
- **Natural Gas Fuel Supply Risk:** The reliability of the BPS faces risks from natural gas generator fuel supply issues, including production or transportation curtailments and limitations during both normal and extreme weather conditions. To mitigate these risks, various strategies have been developed.

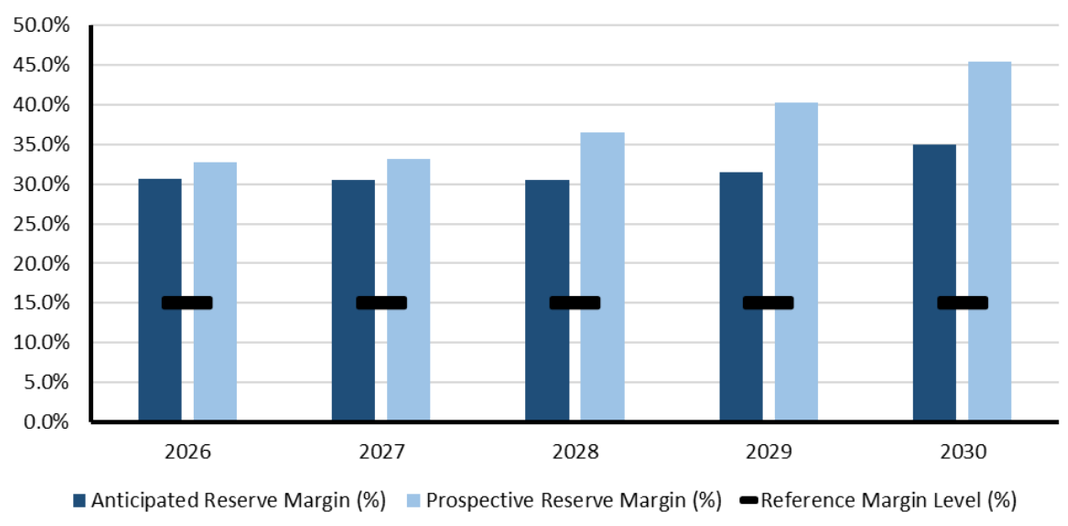


SERC-East

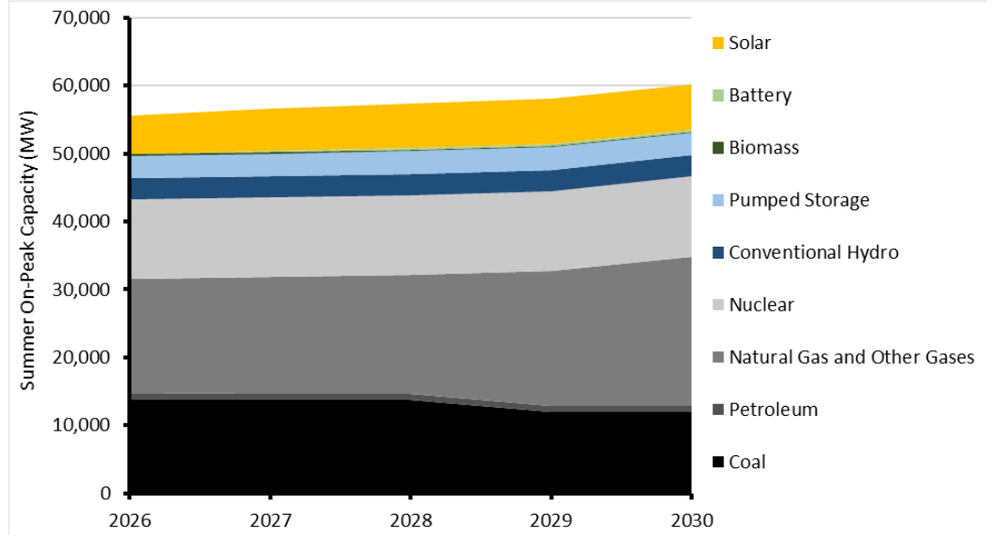
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	44,414	45,289	45,893	46,128	46,646	47,256	47,776	48,445	48,870	49,313
Demand Response	1,608	1,620	1,621	1,652	1,679	1,702	1,726	1,751	1,773	1,795
Net Internal Demand	42,806	43,669	44,272	44,476	44,967	45,554	46,050	46,694	47,097	47,518
Additions: Tier 1	959	2,109	2,817	5,282	7,348	8,656	9,921	11,186	11,186	11,186
Additions: Tier 2	215	484	2,009	3,231	4,045	4,551	5,114	6,232	9,022	9,022
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	150	150	150	236	236	236	236	236	236	236
Existing-Certain and Net Firm Transfers	54,964	54,880	54,953	53,222	53,316	52,237	50,919	50,919	49,557	49,557
Anticipated Reserve Margin (%)	30.6%	30.5%	30.5%	31.5%	34.9%	33.7%	32.1%	33.0%	29.0%	27.8%
Prospective Reserve Margin (%)	32.7%	33.1%	36.5%	40.3%	45.4%	45.1%	44.7%	47.8%	49.5%	48.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-East Highlights

- The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years.
- To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	13,715	13,715	13,715	11,898	11,898
Petroleum	1,044	992	992	992	992
Petroleum*	1,044	868	868	868	868
Natural Gas	16,737	17,081	17,396	19,816	21,851
Biomass	176	176	176	176	176
Solar	5,649	6,223	6,626	6,671	6,702
Conventional Hydro	3,094	3,094	3,094	3,094	3,094
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,808	11,808	11,902
Battery	8	208	258	258	258
Total MW	**55,540**	**56,606**	**57,388**	**58,035**	**60,196**
Total MW*	**55,540**	**56,482**	**57,264**	**57,911**	**60,072**
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins

PRMs in the assessment area are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. However, there are variations among entities. For instance, one generation-only BA with an all-hydro portfolio finds reserve margin requirements inapplicable, while another entity reports sufficient margins. A third entity anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and its targeted 18% winter reserve margin. To address this, it has issued requests for proposals for new capacity resources, including battery energy storage, and is evaluating longer-term options.

Other entities expect their reserve margins to remain above the 15% reference level for both near-term (0–5 years) and longer-term (6–10 years) outlooks, despite significant projected winter load growth of approximately 2% annually, which is expected to increase winter peak demand by about 6,500 MW by 2035. Their IRPs identify substantial new resources through 2035, including thousands of megawatts of solar, battery storage, wind, combustion turbines, combined-cycle units, and small modular nuclear reactors. They also plan to implement uprates to existing units. These entities aim to achieve a 22% winter PRM by 2031. Approximately 5,800 MW of coal generation is slated for retirement over the next decade, but these retirements are contingent on securing sufficient replacement capacity to maintain reliability and meet the 22% winter reserve margin target. Without firm replacement resources, coal retirements would be deferred to preserve system reliability.

Since the *2024 LTRA*, most entities have not significantly changed their resource adequacy planning or procurement processes. One entity, operating hydro-only resources, has not made any changes, nor has another entity that is replacing coal-fired generation with natural gas combined-cycle units, though this shift indirectly enhances reliability. However, a third entity, based on its 2022 LOLE study, increased its winter reference PRM from 12% to 18% by 2026, while maintaining the summer reserve margin at 15%. This adjustment reflects heightened concern over winter reliability risks due to electrification trends and potential load increases. Other companies continue to refine strategies for load growth, resource additions, unit uprates, and retirements, maintaining an “all-of-the-above” strategy.

The RML is typically determined by each entity using probabilistic reliability metrics, commonly targeting a LOLE of no more than 1 day in 10 years, or to comply with state requirements. Entities establish separate summer and winter RMLs, considering factors such as load forecast uncertainty, generator availability, and extreme weather impacts. Planning relies on detailed statistical modeling and ELCC studies to assess resource contributions, particularly for variable energy resources like solar, batteries, and wind. The capacity contribution values for variable energy resources and energy storage are determined by ELCC analyses, which discount nameplate capacity to firm, dependable capacity to meet LOLE standards, while non-variable resources like thermal units are counted at their nameplate capacity. Uncertainty and variability in assumptions are accounted for through “High” and “Low” load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, which in turn drive planning reserve and resource-adequacy sensitivity cases. Although no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources. A reliability verification step within the IRP process ensures that any developed portfolio meets reliability criteria, regardless of its stated installed capacity (ICAP) margin.

Energy Risk, Probabilistic-Based Assessments

Entities within the assessment area exhibit varying approaches to assessing energy risk, with some currently in the early stages of implementation or lacking formal processes. For instance, one generation-only BA with an all-hydro portfolio has not identified any energy risks to date. Another entity has yet to establish a formal energy risk assessment process but is preparing for the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such procedures and assessments. A third entity also acknowledges the importance of developing these capabilities but currently has no established process or results to report.

Despite the current limitations in formal assessments, the sources indicate that key drivers of energy risk expected to be considered in future evaluations include the following:

- Fuel availability constraints, particularly concerning natural gas supply and delivery
- Impacts from unseasonable extreme weather
- Limitations of variable energy resources
- Transmission or interchange constraints
- Correlated outages
- Other factors such as low water conditions, resource outages, and ramping limitations

Entities within the assessment area extensively employ probabilistic reliability metrics and studies as fundamental tools in their transmission and resource planning processes. These assessments are primarily centered on determining resource adequacy and PRMs, with a common objective of achieving a LOLE of no more than 1 day in 10 years. This probabilistic standard is a cornerstone for establishing the reliability needed to meet anticipated demand.

Key probabilistic assessments and their applications include the following:

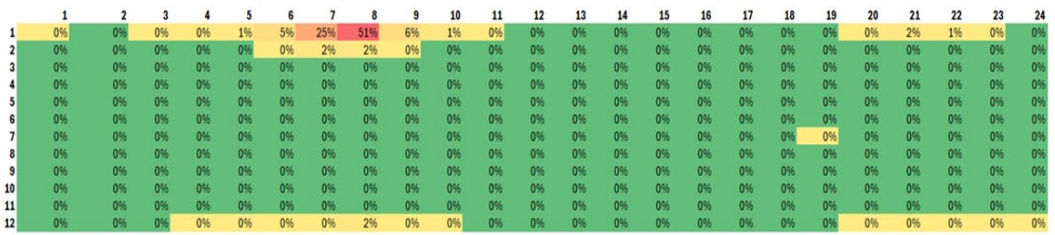
- LOLE Studies: These studies are crucial for setting PRMs. For example, one entity increased its winter reference PRM from 12% to 18% by 2026 following a 2022 LOLE study, reflecting heightened concern over winter reliability risks due to electrification trends. The results from LOLE models are also used in a reliability verification step within IRPs to ensure that proposed resource portfolios can meet reliability thresholds year-round, including accounting for net demand ramping and energy adequacy needs.
- ELCC Studies: These are a specific type of probabilistic assessment used to determine the capacity contributions of VERs such as solar, wind, and battery storage. Unlike non-variable resources like thermal units, which are typically counted at their nameplate capacity, VERs and energy storage undergo ELCC analyses to discount their nameplate capacity to firm, dependable capacity that effectively contributes to meeting LOLE reliability standards. ELCC studies account for factors such as the intermittent, diurnal nature of solar output, especially noting that solar output is minimal during typical winter peak loads (early morning and late evening).
- Statistical Modeling: Entities use detailed statistical modeling to establish separate summer and winter RMLs, considering factors like load forecast uncertainty, generator availability, and extreme weather impacts. While no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources.
- Stochastic Analysis in Load Forecasting: To account for the inherent uncertainties in demand, especially with the addition of large industrial customers like data centers, entities employ stochastic analyses. For instance, one entity uses a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects.
- Load Forecast Uncertainty (LFU) Scenarios: Planning processes integrate “High” and “Low” load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake. These scenarios directly drive planning reserve and resource-adequacy sensitivity cases, allowing planners to assess system resilience under different conditions.

Regarding non-peak hour risk and energy assessments, entities are in varied stages of implementing formal processes. While some currently lack established procedures, they acknowledge the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such assessments. As these formal energy risk assessments are initiated, future reports are expected to include risk quantification tied to specific drivers (e.g., fuel supply constraints, weather-driven demand volatility, system flexibility limitations) using probabilistic metrics across operational time frames, beyond just peak demand hours. These formal energy risk assessments, once fully implemented, are intended to be essential tools for informing strategic planning and operational decisions to ensure resource capacity is available across a broad range of conditions.

ProbA Results

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	143	231	538
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.16	0.33
*Provides the 2024 ProbA Results for Comparison			

The ProbA results for the year 2027 indicate some risk for SERC-East in the winter months of January and February. This is in line with the risk findings of previous ProbA studies. The annual EUE is 231.75 MWh but for a very short, expected duration of 0.15 hours. As shown in the 2027 EUE Heat Map below, the risk occurs during winter morning hours around 7:00-8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. The risk is seen mainly in January but on a smaller scale in the other winter months of February and December. The major contributing weather-years to the EUE in the model are 1982 and 1985, which experienced one of the worst winters throughout the SERC Region, limiting the amount of imports from neighboring subregions.



2027 EUE Heat Map

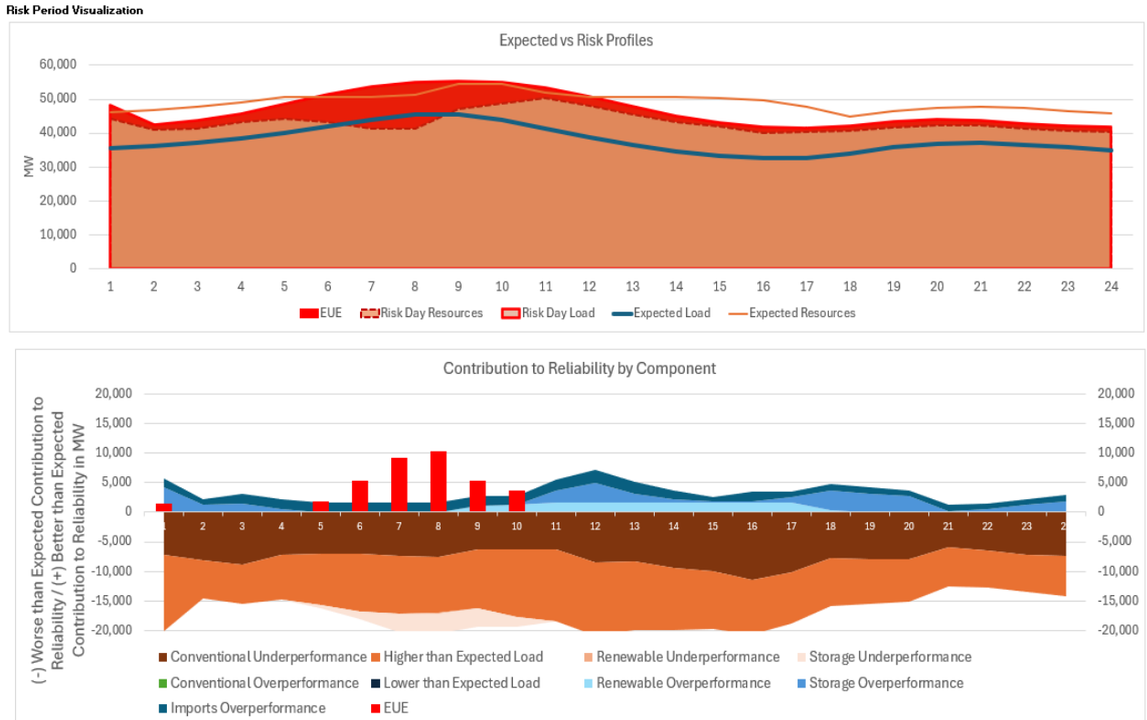
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	1%	7%	23%	41%	9%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	1%	3%	5%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2029 EUE Heat Map

For the year 2029, SERC-East risk continues to grow with 538.48 MWh of EUE and 0.33 hours of LOLH. As is shown in the 2029 EUE Heat Map above, the trends of risk are similar to the findings of 2027, with risk is expected to occur primarily in January, but other winter months of February and December as well. The expected duration of risk is still very short, occurs around 7:00-8:00 a.m. Load is expected to grow in SERC-East. In 2028, more than 1800 MW of coal is expected to retire. While there are some replacements with battery, solar generation, and DR, they are limited in the winter morning risk hours as seen in the study and contribute to the increase in EUE in 2029.

Between 2027 and 2029, the is an expected addition of 683 MW summer load and 985 MW winter load. In the last stages of the ProbA, SERC worked with its entities to identify an error in winter load forecast reporting. We are unable to rerun the model in time for the submission however, we are working with the entities to make the correction to the LTRA. For SERC-East, the overall 2029 winter load forecast should be 1932 MW than is currently reported. The expected risk would be higher along the same trends as is seen in the present study for the year 2029

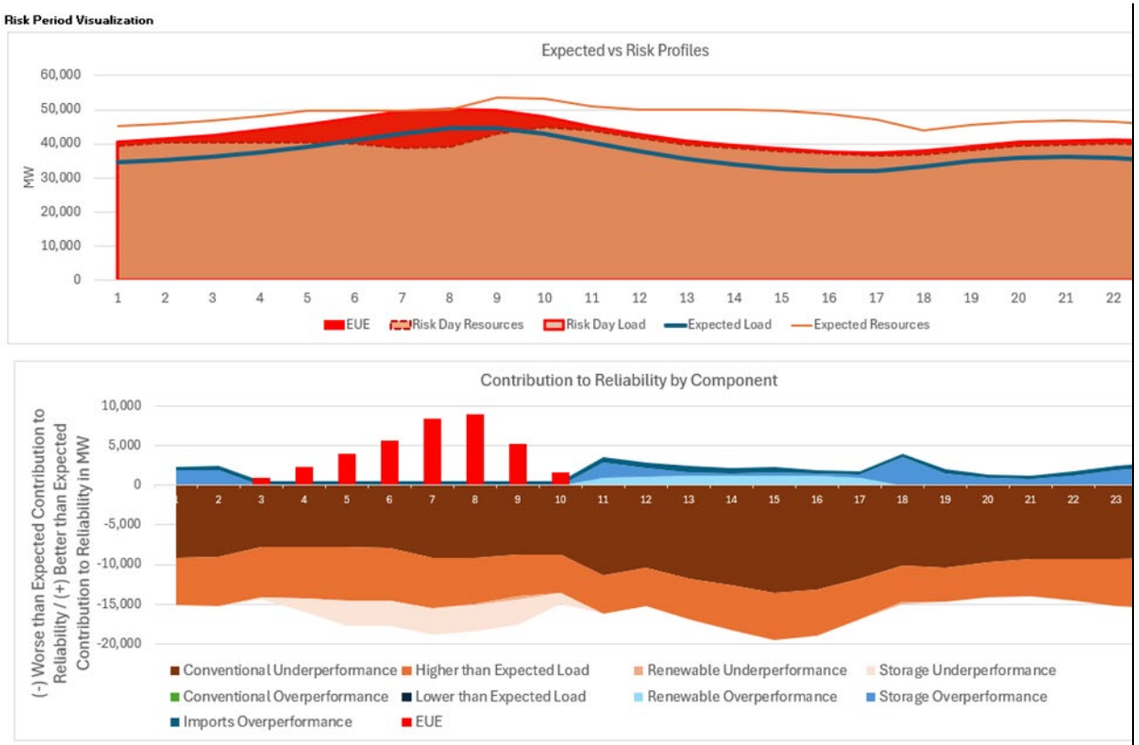
In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2027.



Expected vs. Risk Profiles and Contribution to Reliability by Component

The event day with the worst case EUE hour was chosen for reference (load forecast error +4%, weather year 1985, winter). The chart shows risk during winter morning hours from 4:00-10:00 a.m. and 12:00-1:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. Some imports from neighboring areas are available.

The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029. The event day with the worst case EUE hour was chosen for reference (load forecast error +2%, weather year 1985, winter).



Similar to the 2027 event, there is risk during winter morning hours from 3:00-11:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. While there are some imports from neighboring areas available, it is much lower in this event.

Demand growth and planned generator retirements contribute to growing energy risks. SERC and the SERC East entities will need to continue to monitor the resource adequacy studies.

Demand

The assessment area develops its load forecasts using a combination of short-run and long-run econometric techniques, which are then aggregated into a coincident system peak outlook. One entity uses statistically adjusted end-use (SAE) models for customer classes, supplemented by adjustments for energy-efficiency programs, rooftop solar, and EV forecasts from external consultants. Another entity applies SAE regression for residential and commercial classes, a consultation-based approach for large industrial customers, and a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects. Municipal and wholesale sub-area forecasts are integrated to form the coincident peak, with contracts having defined end dates removed to prevent overstatement of future demand. Load forecast uncertainty (LFU) is addressed through "High" and "Low" scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, driving planning reserve and resource-adequacy sensitivity cases. Since the 2024 LTRA, key refinements include the explicit addition of an EV demand component starting in 2025, more frequent updates for large industrial prospects, and expanded stochastic modeling to capture rising volatility from electrification and BTM generation.

Changes in the 10-year forecasted demand and energy growth rates since the *2024 LTRA* are primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These loads are accounted for via a post-modeling stochastic adjustment from active projects and are a significant driver, contributing approximately 1,100 MW by 2034. Electrification trends, particularly EV adoption, are also included, projected to increase residential and commercial summer peak demand by 33 MW and winter demand by 3 MW by 2034. Rooftop solar is forecast to offset summer demand by 3 MW, with no winter peak impact. Other potential drivers like geographic/demographic shifts, economic outlook, EE (beyond standard modeling), flexible loads, extreme weather, and climate change are currently not considered significant contributors to forecast changes. Beyond the 10-year window, electrification and industrial expansion are expected to continue influencing demand, though uncertainty increases.

Demand-Side Management

DR programs are actively monitored and managed through contractual agreements, control technologies, and performance metrics. DR capacity primarily supports the grid during peak periods, with one entity's capacity mainly from interruptible loads and customer standby generation based on contracted firm demand. Programs focus on winter peak capacity support with some summer use but do not currently address ancillary services. Recent initiatives include a residential DR program (smart thermostat rewards, peak time rebates, time-of-use education) and a residential DR program with load control switches on HVAC units and water heaters, contributing about 2.3 MW based on industry benchmarks. However, efforts to develop more precise baselines for measuring performance have yielded inconsistent results, especially in winter, leading to continued reliance on industry averages. Plans include piloting a "Bring Your Own Thermostat" initiative and transitioning to smart thermostat and other grid-edge technologies due to limitations of current switch-based programs.

Since the *2024 LTRA*, regulatory approvals have expanded incentives for most residential controllable programs (heat strip control, thermostats, water heaters, batteries, except the newer battery program) and increased program coverage. This includes a statewide water heater switch program

launching in 2025, adding November as a winter control month, and enabling year-round water heater control. Emerging technologies like EV batteries, smart panels, home automation, and smart inverters are being monitored for future inclusion. A multi-year initiative has been approved to quantify broader value streams from DR, potentially including energy, regulation, and ancillary services. For non-residential customers, a "Bring Your Own kW" winter load curtailment program is expanding, and two new 2025 programs offer an economic curtailment option and a shorter emergency curtailment program. A planned retirement of one large customer DR program aims to streamline offerings into a unified portfolio called PowerShare.

No major changes have been reported for EE and conservation since the *2024 LTRA*, but refinements are being considered. EE impacts are integrated into load forecast models as post-modeling adjustments, reflecting incremental improvements and new program designs. EE is embedded within customer class forecasts and refined through stakeholder input and ongoing evaluation. Looking ahead, increased focus is expected on load-modifying technologies, smart home integration, and more dynamic EE measurement approaches, potentially through real-time metering data or integration with distributed energy resource management systems (DERMS).

Distributed Energy Resources

DERs, particularly BTM solar PV, are anticipated to experience gradual growth within the assessment area over the next 5 and 10 years, although their current penetration levels remain low. Forecasts project residential solar installations to grow by approximately 8% in 2025, tapering slightly to 7% in 2026 and 2027, and then stabilizing around 6% annually thereafter. These projections are informed by local adoption trends, national market dynamics, and regression models that consider economic payback factors such as installation costs, incentives, and bill savings. Historical metering data also shows a recent decline in new BTM installations due to the expiration of DER incentive programs, which influences future projections.

In terms of integration into planning, BTM solar generation is primarily treated as a load modifier, effectively reducing net load through hourly profiles consistent with prior methodologies. Transmission planning similarly incorporates DER generation as a load reduction rather than a supply resource. For generation planning, the capacity value of solar is assessed through ELCC studies due to its intermittent and diurnal nature. Unlike fully dispatchable thermal resources, which are counted at their full nameplate capacity, solar output varies and typically yields minimal output during early morning and late evening winter peak loads. Summer peak loads align better with solar generation, but its capacity contribution still requires careful assessment through ELCC to discount nameplate capacity to firm, dependable capacity to meet LOLE reliability standards.

The system-level impact of current BTM solar on peak demand and load shapes has been minimal, with no significant operational issues identified from existing penetration levels. BTM solar output is projected to represent only 1% to 1.5% of system load over the planning horizons. While no DER-related reliability risks are anticipated for summer 2025, entities are monitoring for potential localized impacts on midday load in areas with higher solar density. Aside from solar PV, no other types of BTM DERs are currently known to materially affect demand-side profiles.

Regarding DER aggregators, there are currently no active or projected aggregators contributing to electricity demand management within the assessment area, and no such capacity is included in forecasts for the next 5 or 10 years. No formal programs are in place to involve DER aggregators in wholesale electricity markets or Integrated Resource Plans, and no virtual power plants operate within the system. While broader grid reliability studies, particularly concerning IBRs, have been conducted through collaborations like the Eastern Interconnection Planning Collaborative, these efforts have not yet extended to DER aggregation. However, if DER aggregator participation increases in the future, planning practices will be adjusted accordingly.

Since the *2024 LTRA*, there have been no major modifications to DER monitoring or modeling methods. However, future updates aim to distinguish between solar-only and solar-plus-storage DERs. Load forecast uncertainty (LFU) scenarios do account for rooftop solar penetration and BTM generation, reflecting the rising volatility introduced by electrification.

Generation

Generation planning and management within the assessment area involve a comprehensive set of studies and strategies to ensure reliability amidst an evolving resource mix and increasing load growth.

Overall Planning and Resource Mix Evolution

Entities in the assessment area conduct extensive reliability studies as part of their resource planning, including resource adequacy and LOLE studies, typically targeting a reliability standard of no more than 1 day in 10 years. These studies inform integrated resource planning (IRP) processes, which evaluate new generation scenarios and resource transitions.

The resource mix is undergoing significant changes, driven by the following:

- **Retirements:** Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are contingent on securing sufficient replacement capacity to maintain reliability and a target winter reserve margin. For instance, Roxboro units are expected to retire 1,156 MW by 2028 and 1,402 MW by 2033, and Mayo 763 MW by 2030, all dependent on replacement capacity being online. Planning entities proactively manage

these risks through transmission impact studies and will delay retirements if replacement resources are not operational.

- **New Additions:** To meet growing demand and replace retiring capacity, IRPs identify substantial new resources through 2035. These include thousands of megawatts of solar, battery storage, wind, combustion turbines (CT), combined cycle (CC) units, and small modular nuclear reactors (SMR). Some entities are also replacing coal-fired generation with natural gas combined-cycle (NGCC) units to introduce more flexible, dual-fuel generation that supports VER integration.
- **Load Growth:** Significant winter load growth of around 2% annually is projected between 2025/2026 and 2034/2035, increasing winter peak demand by approximately 6,500 MW. This growth is primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These high-load, high-duty-factor customers require resource portfolios capable of sustaining elevated energy demand beyond typical seasonal peaks.

Capacity Valuation and Reliability
For resource adequacy, entities determine PRMs to meet reliability standards.

Capacity Contribution Values: Capacity contributions for different generation types are assigned using a mix of historical performance data and model-based simulations:

- **Variable Energy Resources (VER):** For intermittent resources like solar, onshore wind, offshore wind, and storage, ELCC studies are essential. ELCC studies discount the nameplate capacity of VERs to determine their firm, dependable capacity to meet LOLE reliability standards. Solar output varies and often yields minimal output during early morning and late evening winter peak loads, though summer peak loads align better with solar generation. ELCC values for solar and battery storage are typically updated every three years.
- **Thermal Resources:** Non-solar, wind, and storage resources, such as thermal units, are generally counted at their full nameplate capacity.
- **Hydro Resources:** For hydro-only entities, capacity contributions are based on hydro capacity and remain stable.

Reserve Margins: Reserve margins are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. One entity, however, anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and has increased its winter reference PRM from 12% to 18%. Another entity plans to adopt a 22% winter reserve margin by 2031.

Operational Considerations
Planning activities are actively underway to address potential operational issues from the evolving resource mix:

- **Ramping Needs:** Planning entities estimate ancillary service needs, such as regulation, balancing, and contingency reserves, to ensure operational reliability amid high penetrations of VERs. While some entities with hydro-based or dispatchable, fast-ramping units have no immediate ramping concerns, and others conduct triennial integration studies aligned with their IRPs to assess the system's ability to integrate intermittent generation.
- **Inertia and Stability:** Stability assessments are conducted as part of TPL-001 compliance and interconnection cluster studies. These studies account for new generators and evaluate the growing share of VERs. Results thus far have not revealed significant stability concerns. If a weaker area with lower inertia is identified, further analysis like EMT modeling may be conducted, and adjustments to IBR performance settings or transmission system upgrades are considered.
- **IBRs:** As solar PV integration grows, interconnection studies now mandate the use of EMT models to evaluate IBR performance during disturbances, addressing issues like momentary cessation and fault ride-through. These studies ensure inverter settings comply with NERC standards (e.g., PRC-024) and FERC Order 827. Efforts focus on maintaining network reliability and system stability. While no new ancillary service needs have emerged in the near five-year horizon, entities are considering adopting IEEE 2800 standards.
- **Natural Gas Fuel Supply Risk:** Planning entities have implemented measures to mitigate risks from natural gas fuel supply disruptions, especially during extreme weather. All natural-gas-fired combined cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Future resource planning assumes on-site backup fuel or dual-fuel capability. Long-term studies factor in fuel supply constraints and infrastructure bottlenecks.

Energy Storage
Energy storage (ES) systems, particularly BESS, are anticipated to see significant capacity installations over the coming decade.

Purpose: Much of the planned BESS will be paired with solar facilities to store excess solar generation and enhance system flexibility. The region also operates substantial pumped hydro storage, used to meet load economically and manage generation ramping requirements.

Integration: Energy storage projects are evaluated through generator interconnection studies, modeling both charging and discharging behaviors. Both standalone and hybrid (paired with renewable generation) storage systems are planned for deployment.

Modeling: BESS are modeled assuming a four-hour discharge duration, with capacity contributions varying based on system conditions and resource mix. Hybrid and standalone battery systems are evaluated using ELCC to capture their effective capacity contribution during peak demand periods.

Capacity Transfers

Energy transfer needs and capabilities are undergoing changes, primarily driven by anticipated load growth and the potential retirement of generation resources.

While one generation-only BA does not foresee any changes to its transfer capabilities, other entities acknowledge that the potential retirement of coal plants could constrain transfer capability. To address these potential constraints, new transmission projects are being evaluated and planned. In response to increasing load demands, particularly within specific BAs, multiple active transmission projects are underway to enhance near-term transfer capabilities. Firm transmission service contracts have been secured to support future transfer needs tied to generator retirements, indicating a reliance on these transfers to maintain reliability. Long-term transmission and resource adequacy planning efforts, including IRPs and coordination with neighboring utilities, are ongoing to ensure the region maintains sufficient capacity and transfer reliability. Planning entities model projected resource additions and retirements and incorporate these into transmission models to identify and address any negative impacts through reliability assessments. Long-term firm imports have been requested from neighboring regions to assess whether external capacity transfers might be more cost-effective than developing new local resources, highlighting a consideration for reliance on external capacity for reliability and economic reasons. Potential organizational changes, such as merging BAs, are also being modeled and assessed to ensure system reliability is maintained.

Transmission

Major transmission projects are identified through annual planning assessments to support and maintain system reliability. These projects include new transmission lines (including HVdc), reconductor projects, and power electronic devices like static var compensators (SVC). For instance, a new 230 kV line and synchronous condensers are planned to improve reliability and reduce congestion in coastal areas, and an additional circuit in South Carolina will address low-country congestion. Transmission limitations and constrained areas are identified through annual assessments, but no widespread transmission-constrained areas have been identified in recent planning studies. However, an operating guide exists to manage potential overloads on a specific transmission line. Interconnection study processes are crucial for detecting and resolving potential constraints before new generation is brought online, which helps prevent congestion during real-time operations. Since the *2024 LTRA*, there have not been major changes to transmission planning processes, but entities are actively responding to evolving regulatory requirements, such as FERC Order No. 2023. This includes developing new processes for interconnection heat maps, implementing updated interconnection and affected system processes (including cluster studies), and evaluating grid-enhancing technologies (GET). A business practice is being developed to formalize how GETs will be assessed in both transmission planning and interconnection analyses.

In summary, capacity transfers are important for reliability in this assessment area. System adequacy is maintained through proactive planning for new transmission projects, securing firm transfer contracts, evaluating external imports, and continually refining planning processes to accommodate evolving load and resource dynamics.

Reliability Issues

Entities in East have identified several key reliability issues primarily stemming from projected load growth, an evolving resource mix, and critical infrastructure interdependencies. These challenges necessitate proactive planning and operational adjustments to maintain BPS reliability.

Firstly, large, new load additions, particularly data centers and other industrial facilities, are the primary drivers of significant changes in the 10-year forecasted demand and energy growth rates. These high-load, high-duty-factor customers could strain both generation and transmission resources if not adequately planned for. One entity anticipates potential reserve margin challenges starting in Winter 2027 due to these significant new load additions and is proactively issuing requests for proposals for new capacity resources. All substantial new loads are subjected to interconnection studies to assess their reliability impacts and determine necessary transmission upgrades.

Secondly, the management of generator retirements and the assurance of sufficient replacement capacity pose a significant reliability concern. Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are strictly contingent on securing firm replacement capacity to maintain reliability and meet a target winter reserve margin (e.g., 22%). If firm replacement resources are not in place, coal retirements would be deferred to preserve system reliability. Planning entities actively manage these risks by conducting thorough transmission impact studies to evaluate the effects of retirements on system reliability and to determine required transmission upgrades and replacement generation before allowing retirements to proceed.

Thirdly, the evolving interdependencies with other critical infrastructure sectors, especially natural gas fuel supply, are a major reliability issue, particularly during extreme weather conditions. The risk to BPS reliability from natural gas generator fuel supply issues, such as production or transportation

curtailments, is a recognized concern. Mitigation measures include ensuring that natural-gas-fired combined-cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Coordination protocols exist between electric and natural gas operators for both routine operations and emergency response, including maintaining electric service to critical gas infrastructure like compressor stations. Long-term studies also factor in fuel supply constraints and infrastructure bottlenecks, drawing insights from past events.

Fourthly, the operational impacts of the changing resource mix, particularly the increasing penetration of VERs and IBRs, are actively being addressed. Stability assessments are routinely conducted as part of TPL-001 compliance and interconnection cluster studies to evaluate inertia and transmission stability. While results so far have not revealed significant stability concerns, further analysis, such as EMT modeling, may be conducted in identified weaker areas with lower inertia. Interconnection studies for IBRs now mandate the use of EMT models to evaluate their performance during disturbances (e.g., momentary cessation, fault ride-through) and ensure compliance with NERC standards and FERC Order 827. Additionally, ensuring sufficient flexible resources are available to meet expected system ramping needs is a key planning consideration, with triennial integration studies assessing the system's ability to integrate intermittent generation.

Finally, one entity highlighted that its southern system, which is closely interconnected with neighboring utilities, may face import constraints during the spring and fall shoulder seasons when generation outages are common. To mitigate this, the entity proactively coordinates major generation outages with neighboring utilities and prioritizes reliance on internal generation rather than market purchases during these vulnerable periods. For extreme cold weather, a specific temperature threshold triggers the inclusion of additional operational reserves in its planning process, supported by enhanced forecasting tools. While no widespread transmission-constrained areas have been identified in recent planning studies, new transmission projects are being evaluated and planned to enhance transfer capabilities in response to increasing load demands and potential coal plant retirements, indicating ongoing efforts to prevent future transmission-related reliability issues.

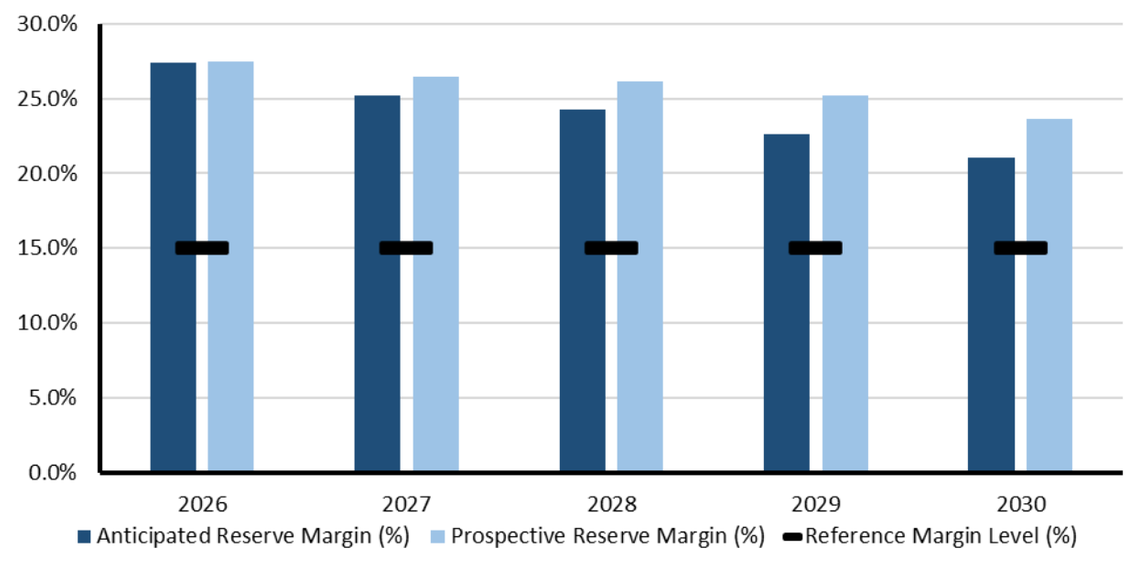


SERC-Florida Peninsula

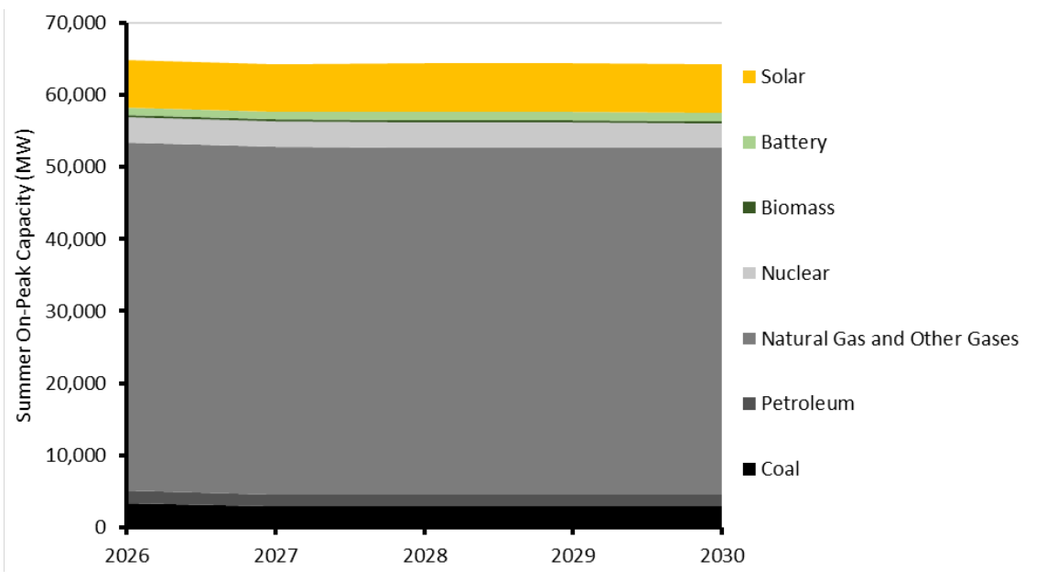
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	54,477	54,933	55,377	56,099	56,666	57,414	58,267	58,972	59,724	60,415
Demand Response	3,345	3,345	3,357	3,360	3,368	3,379	3,388	3,400	3,412	3,418
Net Internal Demand	51,132	51,588	52,020	52,739	53,298	54,035	54,879	55,572	56,312	56,997
Additions: Tier 1	754	800	997	1,000	1,001	1,801	1,801	1,802	1,803	1,803
Additions: Tier 2	32	620	962	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	293	293	200	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	64,393	63,795	63,659	63,659	63,525	63,001	62,966	62,966	62,966	62,966
Anticipated Reserve Margin (%)	27.4%	25.2%	24.3%	22.6%	21.1%	19.9%	18.0%	16.5%	15.0%	13.6%
Prospective Reserve Margin (%)	27.5%	26.4%	26.2%	25.2%	23.7%	22.5%	20.5%	19.0%	17.5%	16.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Florida Peninsula Highlights

- SERC-Florida Peninsula's ARM falls below the RML during the 2035 time frame.
- SERC-Florida Peninsula's ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	3,361	2,902	2,902	2,902	2,902
Coal*	3,346	2,418	2,418	2,418	2,418
Petroleum	1,795	1,667	1,667	1,667	1,667
Petroleum*	1,768	1,459	1,459	1,459	1,459
Natural Gas	48,214	48,202	48,159	48,159	48,025
Biomass	310	310	310	310	310
Solar	6,666	6,712	6,814	6,817	6,818
Nuclear	3,502	3,502	3,502	3,502	3,502
Battery	1,000	1,000	1,095	1,095	1,095
Total MW	64,849	64,297	64,450	64,453	64,321
Total MW*	**64,806**	**63,604**	**63,757**	**63,760**	**63,628**
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Florida Peninsula Assessment

Planning Reserve Margins

The Florida Peninsula subregion annually assesses its PRMs to ensure the regional total reserve margin (TRM) requirement is met over a 10-year projected period, considering summer and winter peak loads, generating resources, and firm DSM resources. The State of Florida's Public Service Commission (FPSC) reliability criterion of a 15% reserve margin serves as the general TRM for entities in the subregion. Notably, investor-owned utilities (IOU) in the subregion voluntarily maintain a higher 20% reserve margin, which also functions as their RML based on firm load. These subregional TRM calculations incorporate merchant plant capacity that is under firm contract to load-serving entities.

Currently, the ARM for the Florida Peninsula subregion is projected to remain above the RML throughout the entire assessment period, indicating no present concerns regarding resource adequacy due to reserve margin deficiencies. Specifically, the projected Regional TRM is above the NERC RML of 15%, and Florida Peninsula subregion reserve margins are anticipated to stay at or above 20% for all summer and winter seasons during the assessment period. This healthy reserve level, coupled with excess import capability, means that the subregion does not foresee changes to its energy transfer needs or capabilities.

Probabilistic analyses confirm that the Florida Peninsula subregion continues to operate below this 0.1 loss of load probability (LOLP) standard. The methods used to calculate the Florida Peninsula RML have remained consistent since the prior LTRA. While individual planners account for uncertainty and variability before submitting their data, which is then aggregated, energy adequacy concerns are not directly addressed within the immediate calculation of ARM/RML. Instead, energy adequacy is reviewed through a biennial Loss of Load Probability Study, which assesses all hours of the year, as well as through transmission and fuel reliability study work. Although no formal changes have been made to existing resource adequacy planning or procurement processes since the *2024 LTRA*, the Florida Reliability Coordinating Council (FRCC) and individual entities are actively considering enhancements, particularly focusing on the increasing penetration of IBRs to ensure sufficient dispatchable generation for potential energy assurance concerns. The FRCC is also continuing to develop its analysis of the 24-hour load and resource outlook around peak days to better understand the impact of increased solar penetration and energy storage charging/discharging on ARM/RML.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The Florida Peninsula Subregion undertakes energy risk assessments to understand its ability to meet uncertain forecasted system demand, particularly as traditional resource adequacy approaches face shortcomings with increasing variability. These assessments are primarily conducted through biennial loss-of-load probabilistic (LOLP) assessments, which are distinct from NERC's ProbA and are designed to assess energy adequacy across every hour of a five-year study period, rather than solely focusing on seasonal peaks. Inputs for these studies include projected generating unit information (current and future capacity), seasonal demand values, projected DR availability, generation maintenance schedules, and Forced Outage Rates (FOR). The FRCC utilizes Astrapé's SERVM Software for multiple base case and sensitivity LOLP studies, with scenarios often examining conditions like no firm import availability, no DR availability, or a 90/10 load case.

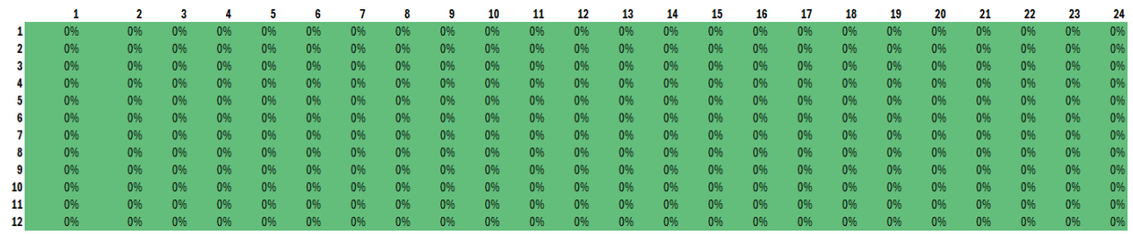
These assessments review a 24-hour load and resource outlook centered around the peak day for both the summer and winter seasons. This effort helps entities fully comprehend the impact of increasing solar penetration levels and energy storage charging/discharging across all hours on the ARM and RML. The analysis has indicated no expected hours of shortfall in adequacy through 2034, though it has observed that increasing solar levels tend to shift the hours of thinnest reserve margins in the summer to later in the day (specifically, HE 18–19).

The FL-Peninsula subregion assesses system adequacy against the industry standard metric of 0.1 LOLP, which equates to approximately one event every 10 years, and currently remains under this standard. Although no significant adequacy impacts have been identified for off-peak hours and shoulder periods, the subregion entities are continuously working to improve their probabilistic analysis methodologies and enhance the robustness of their assessments for these periods. The results of these energy risk assessments are foundational for proactive planning, risk mitigation, and regulatory compliance, guiding long-term strategic decisions like infrastructure development and resource procurement, as well as short-term operational preparedness. The FRCC and its members are also actively considering enhancements to these processes, particularly focusing on the increasing penetration of inverter-based resources (IBR) to ensure sufficient dispatchable generation for potential energy assurance concerns.

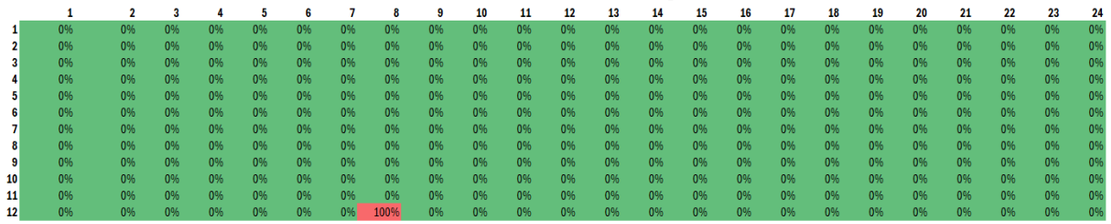
ProbA Results

Based on the data and assumptions of SERC's ProbA model, SERC-Florida Peninsula does not show any loss of load in 2027. For 2029, the annual, probability weighted risk is 0.094 MWh and the LOLH is 0.0001 hours. This is summarized in the table below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	2	0	0.094
NEUE (ppm)	0.01	0.00	0.00
LOLH (hours per Year)	0.01	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			



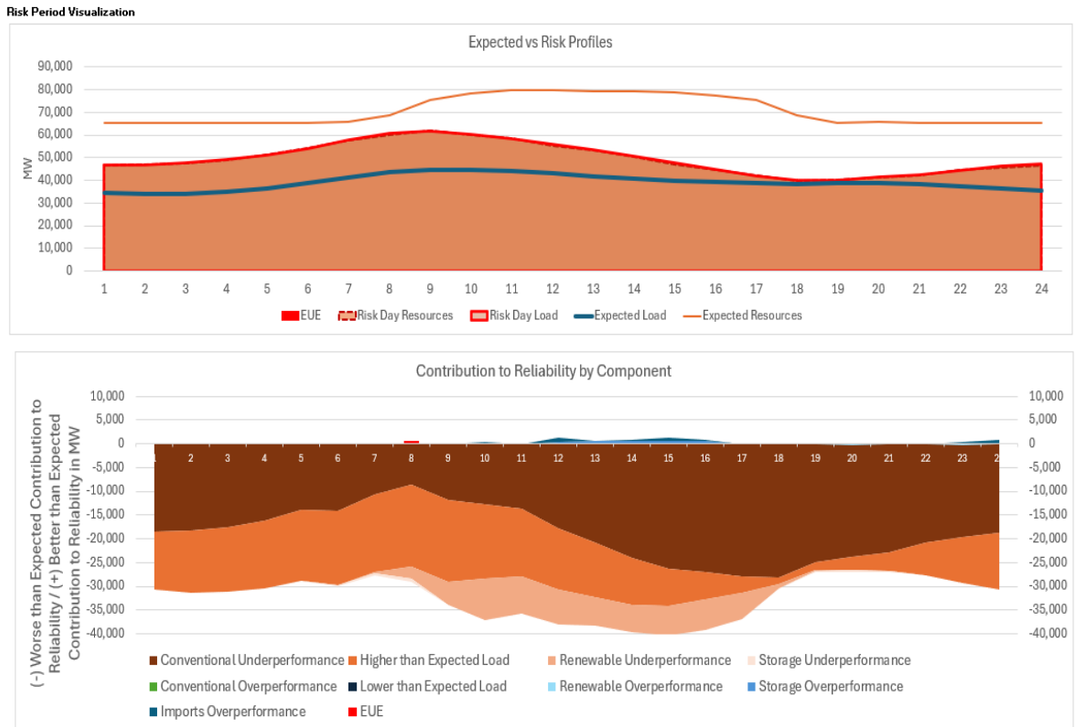
2027 EUE Heat Map



2029 EUE Heat Map

As seen above, the 2027 EUE heat map does not show any risk hours. For study year 2029, there is only one out of 5,375 cases that show risk, which is for a load forecast error of +4%, and weather years 1985 which was an extreme winter year. For that one case, SERC-Florida Peninsula shows an EUE of 720 MWh, with all the risk in December at 7:00-8:00 a.m.

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029 show event details for one risk event for 2029.



Expected vs. Risk Profiles and Contribution to Reliability by Component

Above, the event day as higher than expected load (extreme winter 1985, 4% load forecast error) and resources available are less than expected. The above shows the risk hour to be between 7:00-8:00 a.m. when solar generation is limited, storage and imports are limited. There is some conventional generation on outage.

SERC-Florida Peninsula is also seeing load growth, with an addition of 1,551 MW winter load and 1,146 MW summer load between 2027 and 2029. While the subregion continues to add solar generation, this study indicates that it would not help alleviate risk in cases of extreme winter mornings when solar generation would be very limited.

With the heavy dependence on natural gas in the SERC-Florida Peninsula subregion, fuel diversity could become an area of future concern. Entities in FL-Peninsula have reported a high number of dual-fuel units to mitigate potential disruptions in the natural gas pipelines. Additionally, a new gas pipeline and connection hubs were constructed in the past few years to provide additional gas to the SERC-Florida Peninsula units. The growing penetration of renewable energy means that SERC and the SERC-Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.

Demand

The Florida Peninsula subregion's approach to demand forecasting involves individual entities developing their own load forecasts, which are then aggregated by the FRCC to calculate a non-coincident seasonal peak for the subregion. These individual entities annually adjust their forecasts to account for factors such as actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and EE efforts, and electric appliance usage patterns.

The net energy for load (NEL) as well as summer and winter peak demands are forecasted to grow, with the current average annual growth rate for NEL at 1.1% per year, and firm summer and winter peak demand growth expected to increase to 1.34% and 1.45%, respectively, implying a declining trend for the regional load factor. While some larger utilities account for load profile modifiers like DERs and EVs, smaller utilities either lack sufficient data or deem their current impacts as minimal. The penetration of dependable ac solar capacity and EVs is currently low but expected to grow steadily. LFU is assessed at the individual entity level but is incorporated in FRCC and SERC probabilistic analyses for determining potential Loss-of-Load metrics, though not at the subregional level for Total Demand calculation.

Overall, demand and energy growth rates are projected to increase slightly (between 0.15% and 0.3%) compared to the previous LTRA, driven by population growth, economic performance, electricity prices, changing technology and consumption patterns, and more-efficient building codes. Higher-than-normal temperatures have played a noticeable role in higher average consumption per customer. The impact of data centers or similar large loads is currently minimal and not anticipated to create reliability concerns within the planning horizon, and insights beyond the 10-year forecast are not provided.

Demand-Side Management

DSM programs, controllable and dispatchable DR programs within the Florida Peninsula subregion are treated as a load modifier, projected to remain constant at approximately 6% of the summer and winter total peak demands throughout the assessment period. Each reporting entity independently develops its forecast of firm controllable and dispatchable DR values based on their specific methodologies and program policies, with the FRCC aggregating these impacts for regional analytical purposes. In addition to utility-sponsored EE programs, many utilities also include forecasts of EE associated with the impact from governmental codes and standards. Trends in both utility-sponsored EE and EE from governmental codes and standards remain consistent with prior years, and no modifications have been made to these methods or assumptions since the previous LTRA. Looking forward over the next 10 years, while no changes to how EE and conservation are measured or accounted for have been implemented since the 2024 LTRA, enhancements are actively being considered. These considerations include improved hourly granularity, standardized methodologies, advanced measurement and verification techniques, and better integration of EE into long-term resource planning to support system reliability amidst growing energy demands and increasing renewable integration.

Distributed Energy Resources

The Florida Peninsula subregion systematically monitors and integrates DERs into its planning processes, primarily focusing on BTM solar PV as the most significant type of DER currently identified.

Penetration and Trends: The FRCC conducts an annual collection of DER data across its membership, as reflected in the Load and Resource Plan. While DER penetration levels, particularly for private dependable ac solar capacity and EVs, are currently relatively low, they are forecast to increase steadily over the planning horizon. This includes observed and anticipated year-over-year increases in BTM PV penetration, though these levels remain low compared to the total demand of the Florida Peninsula subregion.

Accounting and Integration in Planning: Entities within the subregion utilize NERC-published definitions for DERs. In general, DERs are modeled as being netted out with the actual customer demand, as their impacts are implicitly accounted for within the load forecasts developed by individual entities. Some larger utilities specifically account for DERs and EVs as load profile modifiers in their forecasts.

Monitoring and Studies: The FRCC's Load Forecast Working Group (LFWG) meets annually to monitor trends in demand sensitivities related to DERs and coordinates on best practices. Additionally, resource planning, transmission planning, and stability analysis subcommittees annually review DER penetration levels to assess whether further study work or sensitivities are required.

Challenges and Reliability Impacts: No additional challenges or significant operational issues have been identified by PCs and Transmission Planners in the assessment area stemming from increased

DER penetration levels at this time. The subregion has not identified any significant BTM resources other than solar PV.

DER Aggregators: Currently, the FRCC and its members do not collect additional data from third-party DER aggregators beyond what is already included in the members' integrated resource plans via their annual data collection process.

Generation

The Florida Peninsula subregion is actively managing its generation fleet to maintain reliability amidst an evolving resource mix, with a particular focus on the increasing integration of IBRs like solar and battery installations, and its continued reliance on natural gas.

Here are the key details regarding generation in the subregion:

- Changing Resource Mix and Operational Considerations:
  - While no significant operational issues have been identified at this time due to the changing resource mix, FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels (solar and battery installations).
  - The FRCC Operating Committee (OC) monitors actual output of solar units and tracks how much additional solar capacity will be online within the next 18 months, discussing any operational issues at monthly meetings.
  - Transmission planning studies, including short-circuit ratios and transient stability analyses, have been conducted to assess the performance of existing and planned IBR installations. These studies indicate that the FRCC system is anticipated to maintain reliable stability performance under expected IBR penetration levels in the five-year planning horizon, with no TPL performance issues identified.
  - Additional study sensitivities include light load conditions with solar modeled at projected output and system strength evaluations.
  - IBR performance issue risks are not considered significant in the near term for the assessment area relative to synchronous capacity.
  - The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.
- Natural Gas Reliance and Fuel Supply Risk
  - The Florida Peninsula subregion is not expecting any long-term reliability impacts resulting from an increased reliance on natural gas-fired generation.
  - The Fuel Reliability Working Group (FRWG) and Resource Subcommittee (RS) periodically study current and projected natural-gas-fired generation levels, including analyses of long-term infrastructure requirements, potential loss of compressor stations, availability of alternate fuel, and extreme weather analyses.
  - Entities in the subregion do not anticipate natural gas supply issues to create reliability risk.
  - Members are projected to hold the vast majority (approximately 90%) of firm pipeline capacity delivering into Florida, supporting increasing gas generation requirements.
  - In the event of a short-term failure of gas delivery infrastructure, there is sufficient back-up fuel capability to meet projected demand. Approximately 55–57% of natural gas generation has alternate fuel capability.
  - Communication protocols include fuel data status reporting by Operating Entities (OE) to the FRCC State Capacity Emergency Coordinator (SCEC) and FRCC RC during threats to fuel availability, integrating this data into enhanced daily capacity assessments.

Net Demand Ramping

No entity has identified any potential issues with net demand ramping within the 10-year planning horizon, as sufficient flexible resources are available. Potential ramping changes are not seen as emerging given current IBR penetration levels and the availability of dispatchable resources. FRCC planning and operating subcommittees plan to further evaluate aggregate system ramping needs over the next few years.

Capacity Contribution Values

Estimates for VERs, including wind, solar, and hydro, and energy storage, are determined by individual members based on actual performance of existing resources and projected performance using industry standard modeling tools (e.g., PVsyst).

Generator Retirements

Confirmed retirements are incorporated into the *Load and Resource Reliability Assessment Report*, while unconfirmed retirements are not tracked. Retirement decisions are made by each entity based on factors such as unit end of lifespan, operating costs vs. new alternatives, environmental regulations, and local sustainability targets. The subregion is not anticipating any negative impacts on reliability from retirements. Confirmed retirements projected have decreased from approximately 3,400 MW in the prior LTRA to 2,150 MW in the current analysis. Entities analyze projected resource

needs in their annual 10-year site plans (TYSP), which include planned retirements and new generation facilities.

Energy Storage

ES is increasingly being integrated into the planning processes within the Florida Peninsula subregion, with methodologies continuously evolving as entities gain more experience in their planning and operation. While entities are modifying their planning processes based on this accumulating experience, no significant modifications have been made to the core VER methods or assumptions, which include ES, since the previous LTRA.

For deterministic analyses, energy storage units are anticipated to be available to provide energy at the time of peak at their full capacity, effectively contributing to peak capacity. However, for probabilistic analyses and energy adequacy assessments, entities are continuing to discuss methodologies to incorporate supply duration and charging time to better reflect the resource's characteristics over time. The FRCC's biennial loss-of-load probabilistic assessments, which review every hour of a five-year study period, help assess energy adequacy and can include considerations for ES.

The impact of energy storage on system adequacy is also evaluated through the FRCC's "2x24 Hour Analysis." This analysis reviews the 24-hour load and resource outlook, helping entities understand more completely the impact of increased solar penetration levels and energy storage charging and discharging across all hours of the peak days on the ARM and RML. This detailed hourly assessment helps observe how ES operations influence system adequacy throughout the day and has indicated no expected hours of shortfall through 2034.

The capacity contribution values for energy storage are determined by individual members, generally based on a combination of actual performance of existing resources and projected performance using industry standard modeling tools. The basis for the percentage capacity contribution considers the nameplate rating of each facility.

Energy storage installations, particularly battery installations, are considered alongside other IBRs. FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels, including these battery installations. The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.

Currently, PCs and Transmission Planners in the assessment area have not identified any additional challenges or significant operational issues specifically stemming from increased DER penetration levels, including ES.

Capacity Transfers

In the Florida Peninsula subregion, capacity transfers primarily refer to anticipated firm import and export values with neighboring assessment areas, particularly the Southern Balancing Authority. While these transfers are an integral part of regional planning, Florida is generally not reliant on external capacity transfers for its core reliability, due to its robust internal generation and healthy reserve margins.

The FRCC Load and Resource Plan (LRP) annually incorporates anticipated firm import and export values reported by member utilities. Recent projections indicate a decline in firm imports for the region over the past few years.

To ensure effective capacity transfers and assess their sufficiency, the Florida–Southern Interface owners conduct an annual transfer capability assessment. This assessment determines the available transfer capability between Peninsular Florida and the Southern Balancing Authority and between the Southern Balancing Authority and FPL Northwest. The results of the most recent analysis project that the interface capability is sufficient to meet anticipated firm import needs.

Transmission

The Florida Peninsula subregion has not identified any specific major transmission projects that impact or are needed to maintain reliability during the planning horizon that are not already identified in the Annual Regional Plan. The individual entities have planned projects that are primarily related to system expansion in order to serve their forecasted growing demand and resource integration and to ensure long-term reliability (beyond the planning horizon). At this time, there have been no changes made to the transmission planning process since last year's reporting.

Reliability Issues

The Florida Peninsula subregion generally maintains a strong reliability outlook, with no other significant emerging reliability issues identified at this time. The ARM is expected to remain above the RML throughout the entire assessment period, meaning there are no current concerns regarding resource adequacy related to reserve margin deficiencies and thus no reliance on Tier 2 resources or supplemental options. Similarly, no potential issues with net demand ramping have been identified within the 10-year planning horizon, and no additional challenges from increased penetration levels of DERs have been identified by PCs and Transmission Planners. Large industrial or commercial load additions, such as data centers, are not anticipated to create reliability risk in the subregion, nor have

any transmission-constrained areas been identified in planning studies. The subregion is also not reliant on external capacity transfers for its core reliability due to robust internal generation and healthy reserve margins.

Even though the Florida Peninsula subregion is not projecting any significant emerging reliability issues, there are areas that the assessment area continues to monitor closely and actively consider for future enhancements or reassessments, indicating underlying risks or concerns that could impact long-term reliability:

- **Increasing Penetration of IBRs and Associated Energy Assurance/Operational Flexibility Concerns:** Although IBR performance issues are "not considered significant in the near-term" for the Florida assessment area at current penetration levels, the increasing integration of IBRs (such as solar and battery installations) is a "key area of focus."
- **Risks of Extreme Weather:** While the Florida-specific energy risk assessments note "no expected hours of shortfall," scenario cases are run that include altered projected load to reflect extreme conditions (e.g., a 90/10 case), demonstrating an awareness of these potential risks.
- **Dependency on Natural Gas as a Fuel Resource:** Despite that Florida does not anticipate any natural gas supply issues that may create risk to reliability and has developed robust mitigation strategies (such as holding approximately 90% of firm pipeline capacity and having 55%–57% of natural gas generation with alternate fuel capability), the area's "dependency on natural gas as a fuel resource" is still factor where possible impacts on the long-term reliability of the BES are continuously monitored.

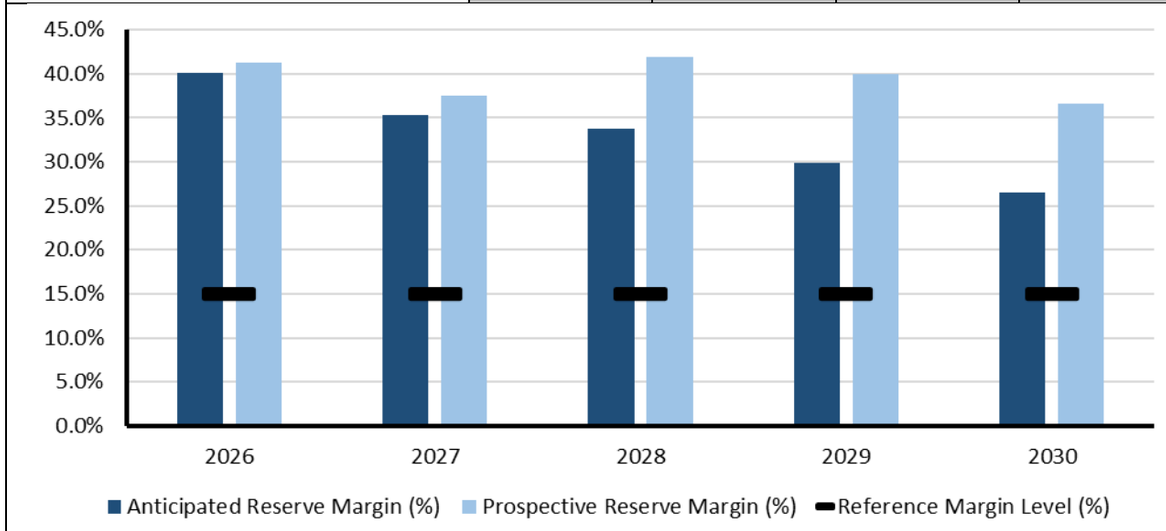


SERC-Southeast

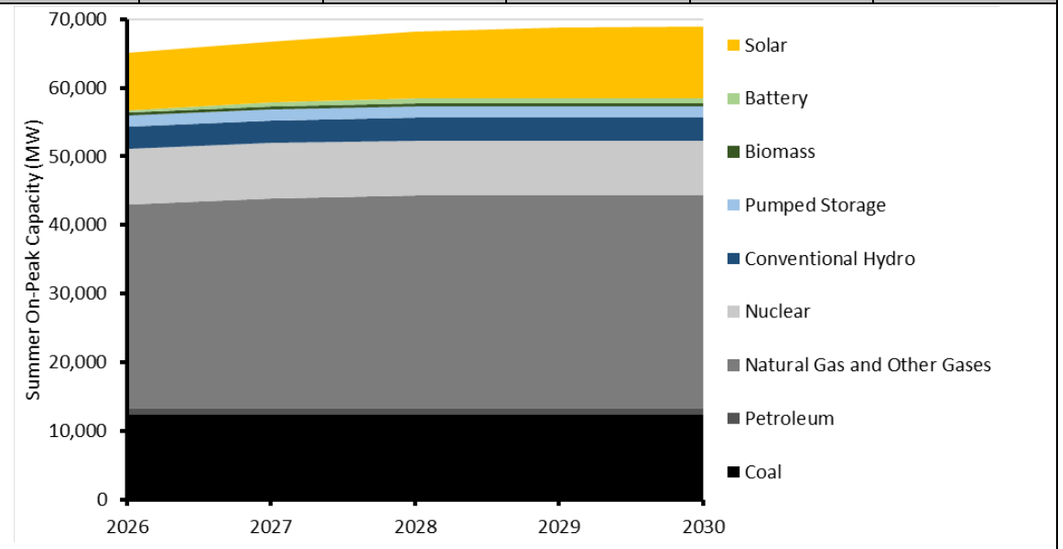
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	48,386	50,648	52,900	55,127	56,624	57,544	57,978	58,552	59,004	59,166
Demand Response	1,358	1,391	1,623	1,634	1,640	1,650	1,656	1,664	1,671	1,677
Net Internal Demand	47,028	49,257	51,277	53,493	54,984	55,894	56,322	56,888	57,333	57,489
Additions: Tier 1	684	2,262	3,704	4,395	4,474	4,474	4,474	4,474	4,474	4,474
Additions: Tier 2	0	516	3,687	4,889	4,989	4,989	4,989	4,989	4,989	4,989
Additions: Tier 3	0	150	250	500	500	500	500	500	500	500
Net Firm Capacity Transfers	814	-53	414	619	619	619	619	619	619	619
Existing-Certain and Net Firm Transfers	65,201	64,393	64,860	65,065	65,065	65,065	65,065	65,065	65,065	65,065
Anticipated Reserve Margin (%)	40.1%	35.3%	33.7%	29.8%	26.5%	24.4%	23.5%	22.2%	21.3%	21.0%
Prospective Reserve Margin (%)	41.3%	37.5%	42.0%	40.0%	36.5%	34.3%	33.3%	32.0%	30.9%	30.6%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Southeast Highlights

- SERC-Southeast's ARM does not fall below the RML during the 2025–2035 time frame.
- SERC-Southeast's ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	12,403	12,403	12,403	12,403	12,403
Coal*	12,403	12,403	11,145	11,145	11,145
Petroleum	866	866	866	866	866
Natural Gas	29,765	30,646	31,057	31,057	31,057
Natural Gas*	29,751	30,632	31,043	31,043	31,043
Biomass	428	428	428	428	428
Solar	8,358	8,836	9,667	10,358	10,358
Conventional Hydro	3,292	3,292	3,292	3,292	3,292
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	279	557	757	757	836
Total MW	65,042	66,678	68,120	68,811	68,890
Total MW*	65,042	66,678	66,862	67,553	67,632
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

PRMs in the Southeast assessment area highlight a proactive and stable approach to ensuring grid reliability, with ARMs projected to remain above reference or target levels throughout the long-term assessment period. Utilities in the region typically plan for a 15% reserve margin, a target that has remained unchanged from prior years. Capacity plans are specifically designed to maintain 15% reserve margins in summer and 25% in winter, consistent with previous long-term assessments. The annual IRP process is crucial, as it addresses resource adequacy well in advance, ensuring that reserve margins consistently stay above these required levels, considering both primary and secondary generation resources.

The methodologies for determining these RMLs are robust and comprehensive. A LOLP analysis is conducted to ascertain if adjustments are necessary to maintain a 1-in-10-year LOLE. This analysis relies on assumptions concerning system loads, potential outages, transfer capabilities, and resource plans, drawing from historical and forecasted data. To account for uncertainties, these assumptions are stress-tested through Monte Carlo simulations across a range of best- and worst-case scenarios, calculating EUE at current RMLs. One utility, which operates independently of state regulatory oversight, conducts its own triennial reserve margin study (RMS) to pinpoint an economically optimal reserve level. This RMS balances capacity costs, production costs, and the costs associated with unserved energy, utilizing a wide array of data including weather variability, unit reliability, fuel availability, and market conditions to model hourly system operations and assess the risk and cost of potential capacity shortfalls. Furthermore, resource adequacy assessments are evolving to include advanced capacity accreditation methods like perfect capacity (PCAP) and ELCC, which more accurately reflect the reliability contributions of VERs. For instance, one ELCC study increased solar peak credit from 50% to 89% for certain solar capacity. No significant changes have been made to reserve margin modeling or resource procurement processes since the previous LTRA, and none are planned for the next decade regarding resource adequacy planning, though input assumptions are regularly updated.

Despite maintaining adequate reserve margins, energy risk assessments highlight an important nuance: reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also crucial. Results from these assessments may prompt policy updates or recalibrated targets for PRM policies to better align with actual risk levels identified across the year, including non-peak hours. To address identified capacity needs or potential shortfalls, the IRP process leads to procurement actions approved by regulatory commissions. New resource technologies are selected based on their technical, economic, and capacity attributes. For example, one utility intends to maintain its 15% reserve margin by incorporating potential capacity purchases of up to 370 MW to serve anticipated data mining loads over the next four years, alongside plans to add solar and battery resources in 2029. Overall, planning entities consistently update their capacity expansion plans annually to meet load requirements and adhere to these PRMs.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy risk assessments in the Southeast assessment area utilize a combination of deterministic and probabilistic methods to identify and address potential energy shortfalls across various planning horizons. These assessments incorporate crucial assumptions about fuel availability, generation outages, extreme weather events, and transmission capabilities. Winter peak hours have been identified as the highest-risk period for energy shortfalls, driven primarily by volatile peak demand during extreme cold weather events that exceeds forecasts, and sustained overnight load where demand remains high throughout the evening and early morning, eliminating traditional off-peak troughs. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours.

A significant finding from these assessments is that fuel availability, particularly for natural gas, presents a risk, especially in systems with limited renewable penetration. Entities are mitigating this by securing firm pipeline transportation contracts for baseload plants and ensuring onsite fuel storage (natural gas or fuel oil) for peaking units. Probabilistic modeling, including Monte Carlo simulations, evaluates the impact of these drivers, calculating metrics such as LOLE and EUE; these studies show increased risk in winter and significant EUE increases under fuel-constrained scenarios. Crucially, the results underscore that reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also vital.

Furthermore, scenarios modeling low hydro output and low solar generation during high-demand periods (especially in winter or prolonged cloudy conditions) indicate increased energy risks when variable energy resources (VERs) underperform. While annual production cost simulations performed in an “island” mode (excluding market purchases) have not identified energy deficiencies under base conditions, the RMS provides a comprehensive probabilistic analysis of hourly energy adequacy by simulating thousands of scenarios and considering historical weather, load, solar availability, fuel constraints, and generator outages. The RMS also assesses regional interdependency risks, finding that transmission constraints can hinder economic and emergency imports, exacerbating local energy shortages during widespread events. Energy risk assessments reflect a maturing focus on year-round, all-hour reliability, emphasizing risks from fuel supply chains, weather variability, and the increasing integration of variable renewable energy sources. These findings may lead to policy updates or recalibrated targets for PRM policies (e.g., 15% summer/25% winter) to better align with actual identified risk levels.

ProbA Results

SERC-Southeast does not show any loss of load risk for the year 2027, the EUE is 0.00 MWh and LOLH is also 0.00 hours. For the year 2029, there is a small ANNUAL risk of 0.39 MWh and 0.001 hours.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0.0	0.4
NEUE (ppm)	0.00	0.00	0.001
LOLH (hours per Year)	0.00	0.00	0.001
* Provides the 2024 ProbA Results for Comparison			

The figure below shows the EUE as a Heat Map for the year 2027.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

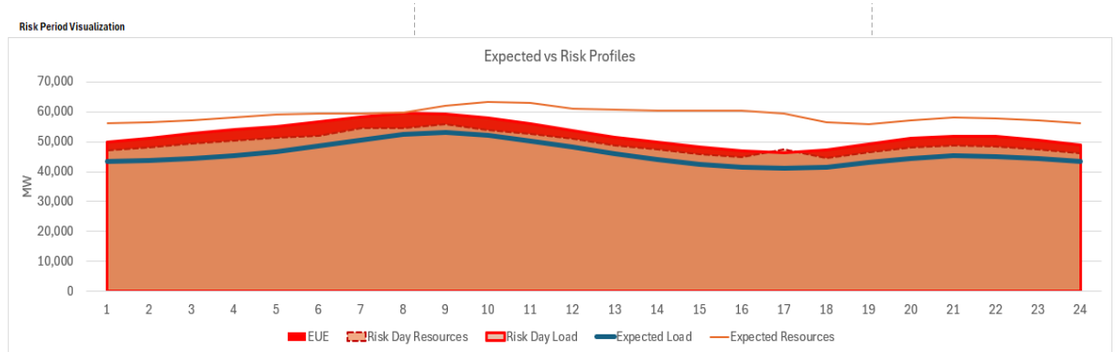
2027 EUE Heat Map

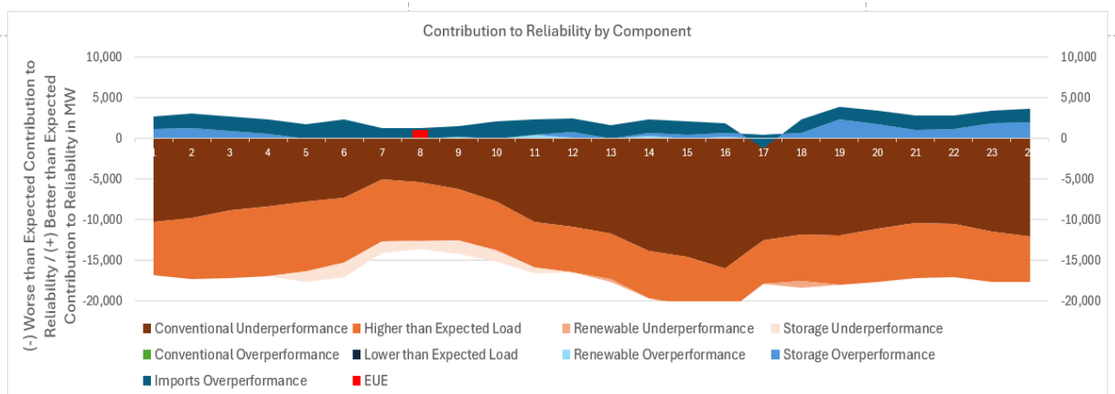
For the year 2029, there is a small annual risk of 0.39 MWh and 0.001 hours. There are some iterations of cases in the 2029 case, for load forecast error +2% and +4%, there is an EUE of up to 1,006 MWh. As shown in the figure below, higher load forecasts, particularly during extreme cold weather events such as weather years 1982, 1985, and 2022, contribute to risk in winter mornings (7:00-8:00 a.m.) and nights (10:00 p.m.-12:00 a.m.). December shows the most risk, followed by January.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%	29%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	22%	0%

2029 EUE Heat Map

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1000 event or higher probability, so the event day with the highest EUE in an hour was selected. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029.





The top figure compares the event day to a typical day in December, with weather year 1985, which was an extreme cold event. The lower figure shows the loss of load between 7:00-8:00 a.m. when the load is higher than projected, solar generation is unavailable, energy storage and imports are available during the risk hour.

Between 2027 and 2029, SERC-Southeast is expected to add battery and solar generation Tier 1 resources. The addition of solar generation, however, would not help alleviate risk that occurs in winter morning or winter night hours when solar irradiation is unavailable. Georgia Power Company has publicly filed their intent to build company owned combined cycle, battery energy storage systems, hybrid solar and battery energy storage systems, coming online between 2029 and 2031. However, the commission has yet to vote on approval, expected to do so in December and are not included in the model. SERC-Southeast is not expected to retire additional generation during this time.

SERC-Southeast is seeing high load growth. Between summer 2027 and 2029, there is expected to be an addition of 4,468 MW of summer load and 2,134 MW of winter load.

With the growing dependence on natural gas as the predominant energy source in the SERC Southeast subregion, fuel diversity could become an area of future concern.

Demand

The entities in the Southeast assessment area employ a robust approach to developing their load forecast for the LTRA. This methodology combines econometric modeling, statistically adjusted end-use (SAE) analysis, and hourly bottom-up aggregation across members. Forecasts are annually updated based on historical data and the latest S&P Global economic outlook, using regression models that account for weather, economic indicators, population, appliance efficiency, and load shapes. Both coincident and non-coincident peak demand forecasts are included and refined using specialized tools. LFU is addressed by testing load levels ranging from 80% to 104% of projected peak demand, with weather identified as the primary driver of variability. While DERs like rooftop solar currently have minimal impact, their potential effects are considered in sensitivity scenarios. No major changes have been made to the core forecasting methodology since the prior LTRA, though input assumptions are regularly updated.

Several factors contribute to the 10-year forecasted demand and energy growth rates. Data centers are a significant and highly uncertain consideration, capable of substantially increasing demand when included as a sensitivity in reliability studies, with nearly 400 MW of data mining load expected by 2025. These loads often exhibit unpredictable behavior, with some shifting to 24/7 operation, flattening the overnight load curve and extending peak periods, which complicates traditional peak-centric planning. Large commercial and industrial loads are expected to contribute to energy growth in specific economic development areas. Electrification trends are emerging slowly, with limited current impact on forecasts, though home heating electrification is notably contributing to increased winter peak sensitivity. Beyond the 10-year horizon, transportation electrification is anticipated to become a more significant driver of load growth. The influence of climate change and extreme weather on load forecasting is modest in most cases, with some utilities refining models to reflect more frequent cold weather patterns. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours. EE improvements are occurring but are not yet deemed a significant overall impact, and flexible or price-sensitive loads are typically modeled on the supply side, thus excluded from direct demand forecasts.

Demand-Side Management

Depending on the entity, DSM could be a voluntary DSM water heater program, which allows for limited control of appliance usage during peak demand periods, with the number of installed control switches tracked monthly to forecast future participation. Load research data is used to estimate the diversified load contribution from these devices. While the entity is monitoring how new EE regulations may impact program effectiveness and developing a DSM measurement and verification (M&V) framework, its analysis currently relies on historical load research data. DR resources under contract are monitored and dispatched, and annual ELCC simulations determine the capacity value of each active DR program. BTM DERs are accounted for within annual load forecasts, while front-of-the-meter (FTM) DERs are treated as generation assets. The entity is also exploring new DR and flexibility programs, including pilot efforts in commercial and industrial automated DR and solar-plus-storage, and implementing a DERMS to enable broader coordination. No modifications to DR methodologies or assumptions have been made since the *2024 LTRA*, but new pilot programs and system capabilities are actively being developed. For EE and conservation, no significant changes have occurred in measurement or accounting since the prior LTRA. EE impacts are generally incorporated through adjustments to load forecasts based on federal and state efficiency standards, appliance saturation trends, and building code updates, reflected in econometric models or end-use forecasts that estimate reduced energy consumption over time.

Distributed Energy Resources

The estimated penetration of DERs in the Southeast assessment area remains modest, with forecasts projecting 1–1.5% of peak load over the next five years and staying below 2% over a 10-year horizon. Specifically, BTM solar PV is expected to grow from 57 MW by 2030 to 120 MW by 2035. Currently, DERs and rooftop solar are considered to have minimal impact on overall reliability, with no emerging transmission or resource adequacy issues directly attributed to them anticipated for Summer 2025.

In terms of planning, BTM DERs are accounted for within annual load forecasts and are not explicitly modeled as discrete capacity resources. Instead, they are represented using hourly generation profiles to account for operational factors like ramping, and estimated generation is placed back onto load buses when installations reach or exceed 2 MW. Conversely, FTM DERs are treated as generation assets. While BTM solar is contributing to energy availability and reducing fossil fuel consumption, their limited capacity value and variability are creating challenges, particularly during the sunrise and sunset hours, requiring greater flexibility from non-solar resources. Solar-related ramping concerns and energy adequacy under evolving weather conditions are considered emerging reliability challenges, which are actively being studied through triennial renewable integration studies. Load forecast uncertainty related to DERs is addressed by considering their potential effects in sensitivity scenarios, such as assuming zero DER contribution under stress conditions.

Generation

The Southeast assessment area actively manages its generation portfolio to ensure reliability amid a changing resource mix, with particular focus on the increasing integration of utility-scale solar and other VERs. While current renewable penetration is modest, leading to no significant stability or inertia issues observed to date, future challenges like intra-hour volatility and ramping needs are being proactively evaluated. The Renewable Cost and Benefit (RCB) Framework is utilized to assess integration costs and identify mitigation strategies such as flexible backup resources.

Regarding net demand ramping, the assessment area does not currently identify any emerging issues due to the limited penetration of VERs and a robust, flexible generation portfolio primarily composed of natural gas units. Annual analysis of five-minute ramping data is conducted to inform regulating reserve requirements, and existing natural-gas-fired units, supported by firm fuel supply and fuel-switching capabilities, are deemed sufficient to meet current and projected ramping needs.

Capacity contribution values for VERs like solar and wind are determined using a combination of historical performance data and ELCC analyses via the SERVM reliability and production cost model. For solar, contributions are initially set at 50% of nameplate capacity during May–September, with annual re-evaluation based on actual performance, though no contribution is assigned in winter due to the assessment area's winter peak planning season. An ELCC study in 2024 notably increased solar peak credit for up to 340 MW of solar capacity. While energy storage resources are evaluated through ELCC, with a preferred minimum duration of two hours, no operational storage resources are currently on the system. Hydro resources are credited at 100% due to firm delivery contracts.

Efforts to address IBR performance issues include enhanced interconnection studies that assess various factors like thermal loading, voltage stability, and short circuit performance. EMT models are now required from Generator Owners to better simulate and understand IBR behavior during disturbances, and mitigations include adjusting ramp rates and enforcing ride-through requirements. Additional phasor measurement units (PMU) are being deployed to enhance real-time situational awareness, particularly at IBR interconnection points. While current IBR penetration is low, network impacts and protection coordination are identified as the primary reliability concerns being addressed.

Generator retirements have seen no changes to confirmed or unconfirmed projections since the *2024 LTRA*, with no unit retirements currently projected over the 10-year planning horizon. All native generation, including coal, natural gas, and nuclear resources, is expected to remain available to meet peak demands. Planning entities have established processes involving detailed studies over a 10- to 20-year horizon to assess potential reliability impacts of retirements, considering mitigations such as transmission infrastructure capital improvements or dynamic VAR support. The IRP process coordinates retirement schedules with the addition of replacement capacity to prevent reliability gaps.

Natural gas fuel supply risk is actively managed, with approximately 78% of winter on-peak natural gas generation capacity having either firm fuel supply arrangements or backup fuel options like oil or dual-fuel capability. Annual gas pipeline failure studies are conducted ahead of each summer and winter season to assess impacts under various curtailment scenarios. Communication protocols between electric system operators and natural gas operators are maintained for coordinated responses. Long-term planning processes incorporate fuel risk through load capability analysis and production cost modeling over a 20-year horizon, ensuring capacity plans meet PRMs.

Energy Storage

While there are currently no operational energy storage resources on the system in the Southeast assessment area, future plans do include the addition of solar and battery resources by 2029. BESS are recognized as IBRs that, like solar, require different modeling and analysis techniques compared to traditional synchronous generation. The uncertainty surrounding the future locations and generation outputs of new BESS is noted as a factor that complicates proactive planning.

For planning purposes, energy storage resources are primarily evaluated for their capacity contribution through ELCC analyses. A preferred minimum duration of two hours is considered for operational reliability when evaluating energy storage resources, although there is no formal duration requirement currently enforced. Pilot programs are also being explored, specifically solar-plus-storage initiatives, as new DR and flexibility programs. These programs aim to provide flexible capacity and fast-start capabilities to the system.

No major methodology modifications have been made to the methods or assumptions for incorporating energy storage since the *2024 LTRA*.

Capacity Transfers

Capacity transfers are important for reliability in the Southeast assessment area and the SERC Region. System adequacy is maintained through planning studies and coordination with neighbors to manage evolving energy needs and maintain regional reliability.

Currently, surplus capacity for transfer and delivery is anticipated to remain available to meet reliability margins and support marketing opportunities. Transmission flow patterns are becoming more dynamic due to shifts in internal and external resource portfolios, retirements, additions, and system topology adjustments, but no significant impacts to firm transmission contracts have been

identified to date. Furthermore, recent reserve margin studies suggest that current transmission capabilities do not pose a constraint on resource adequacy within the assessment area.

To facilitate and ensure reliable capacity transfers, the assessment area engages in extensive coordinated efforts, studies, and protocols with neighboring assessment areas for both peak and non-peak hours. These coordinated efforts include:

- **Joint Transmission Planning Studies**, such as the Southeast Regional Transmission Planning (SERTP) process, which evaluate the BPS's ability to support transfers under various seasonal and system conditions, accounting for projected load growth, generation changes, and transmission upgrades.
- **Firm Transfer Agreements and Modeling**, which are integrated into seasonal and long-range planning studies to ensure deliverability under normal and contingency conditions. These agreements are regularly reviewed and updated.
- **Seasonal Coordination Studies**, including power flow, stability, and transfer capability analyses, conducted prior to each summer and winter season to assess the ability to maintain reliability and meet transfer obligations under expected and extreme conditions.
- **Contingency and Emergency Protocols** with neighboring BA and Reliability Coordinators to support emergency situations and real-time transfers. These protocols are exercised through reliability drills and supported by tools like dynamic line ratings and real-time data sharing.
- **Reserve Sharing and Balancing Arrangements** that enable entities within the assessment area to share generation reserves during system events or peak demand periods, supporting both operational reliability and economic efficiency.
- **Real-Time Operational Coordination** where neighboring areas monitor real-time flows and manage congestion through dynamic scheduling, redispatch strategies, and curtailment procedures as necessary.
- **Coordinated use of the Open Access Same-Time Information System (OASIS)** to ensure transparency and proper scheduling of transfers, preventing violations of reliability standards or operational issues.

Despite these robust coordination mechanisms, energy risk assessments have highlighted certain limitations regarding external reliance, particularly during extreme conditions. Studies, including the RMS, have modeled interactions with 13 neighboring systems to understand the limits of market support during high risk periods. These assessments indicate that regional transmission constraints can hinder economic and emergency imports, potentially exacerbating local energy shortages during widespread events. Furthermore, studies suggest limited excess market generation availability during extreme weather events in the Southeast, underscoring the critical importance of internal resource adequacy planning.

In terms of future reliance, while the overall trend suggests sufficient internal capacity, one utility expects to potentially make capacity purchases of up to 370 MW to serve possible data mining loads over the next four years. This indicates a willingness to utilize external purchases to meet specific, potentially high-density and unpredictable, new loads. The results of energy risk assessments are used to inform capacity expansion plans and determine the need for additional capacity purchases.

Transmission

Entities within the assessment area have numerous transmission projects planned or underway over the next 10 years to support system reliability and address evolving load and generation needs. These projects include approximately 1,308 miles of new transmission lines above 100 kV, 1,322 miles of line rebuilds, around 20 reactive compensation installations, 50 new transmission stations, and various upgrades to increase the capacity of existing infrastructure. One entity plans to retire a 46 kV transmission path and convert affected delivery points to 115 kV service, constructing a new network line to address localized thermal constraints and improve contingency performance. Power electronic devices such as reactive compensation systems are being installed to enhance voltage stability and system performance. While no major transmission adequacy issues have been identified, there are risks of project delays due to supply chain disruptions and contractor availability. Mitigation measures include staggered project timelines, strategic inventory management, and evaluation of interim technologies like variable line impedance devices. Overall, the assessment area maintains a coordinated and proactive transmission planning approach to ensure continued reliability across the region. Since the *2024 LTRA*, planning entities across the assessment area have begun implementing or exploring several enhancements to their transmission planning processes in response to evolving reliability, resource mix, and regulatory conditions. One key area of focus is the growing presence of IBRs, such as solar and battery storage, which require different modeling and analysis techniques compared to traditional synchronous generation. Entities are now incorporating additional scenarios into their long-term planning to assess the adequacy of the transmission system under various levels of IBR penetration, particularly in areas experiencing rapid deployment of utility-scale renewables.

Another significant development involves planning for large data center loads, which present unique challenges due to their high energy consumption and sensitivity to power quality. Entities are preparing to implement new technical studies—such as dynamic modeling and harmonic analysis—to ensure that these loads can be reliably served without compromising grid stability. These studies are expected to become increasingly important over the next 10 years as data centers proliferate across the region. While there have been no wholesale changes to core transmission planning methodologies, adjustments are being made to better reflect recent operating experiences. For

example, entities have refined the load levels used in extreme case scenarios to align more closely with observed peak events. There is also growing interest in performing comprehensive gas-electric interdependency studies to assess the risks posed by natural gas supply disruptions to gas-fired generation resources.

For non-FERC-jurisdictional entities, FERC Order No. 2023 is being monitored, and although compliance is not mandatory, potential alignment with its principles—such as improved generator interconnection procedures and enhanced transparency in queue management—is being considered.

Regional coordination remains a critical component of transmission planning. Entities continue to work closely with first-tier neighbors through long-term, quarterly, and weekly coordination protocols. Interface transfer capabilities are calculated regularly on monthly and two-day-out bases, with requests managed through the OASIS system. Coordination of transfer capability assessments and planning assumptions is also carried out through interregional forums, such as the SERC Long-Term and Near-Term Working Groups and the Southeastern Regional Transmission Planning process. These efforts ensure that planned projects and operational practices are aligned across the region, helping to maintain reliability as system conditions evolve.

Reliability Issues

The Southeast assessment area actively manages its generation portfolio to ensure reliability amidst a changing resource mix. While no significant stability or inertia issues have been observed to date due to the current modest renewable penetration, several evolving reliability concerns are being proactively addressed:

- **Elevated Winter Energy Risk and Sustained Overnight Loads**: Energy risk assessments consistently identify winter peak hours as the highest-risk period for energy shortfalls. This increased risk is driven by two primary factors: volatile peak demand due to extreme cold weather events exceeding forecasts, and sustained overnight load where demand remains high throughout the evening and early morning. Recent winter events, such as Winter Storm Elliott, have led to updated load shapes that reflect higher and more sustained loads, underscoring the importance of energy adequacy beyond just peak periods. This indicates a shift requiring more continuous energy coverage rather than just peak-hour capacity.
- **Natural Gas Fuel Supply Vulnerability**: Fuel availability, particularly for natural gas, has emerged as a significant energy risk. To mitigate this, entities in the assessment area actively manage natural gas fuel supply risk through firm fuel arrangements, backup capabilities like onsite fuel storage or dual-fuel options (e.g., oil), and annual gas pipeline failure studies conducted before each summer and winter season. Communication protocols are also maintained between electric and natural gas system operators for routine and contingency operations. Long-term planning studies also incorporate considerations for gas production limitations and transportation bottlenecks.
- **Challenges Posed by Large Industrial and Commercial Load Additions**: The assessment area is experiencing an increasing demand of large industrial and commercial load additions, such as data centers and crypto mining facilities, which require enhanced coordination, especially with local distribution cooperatives. These loads can “substantially increase demand” and exhibit unpredictable behavior, with some shifting to 24/7 operation and relying on short-term capacity purchases. Entities are proactively developing updated technical interconnection requirements and pursuing regulatory approvals to procure additional generation to serve these new loads.

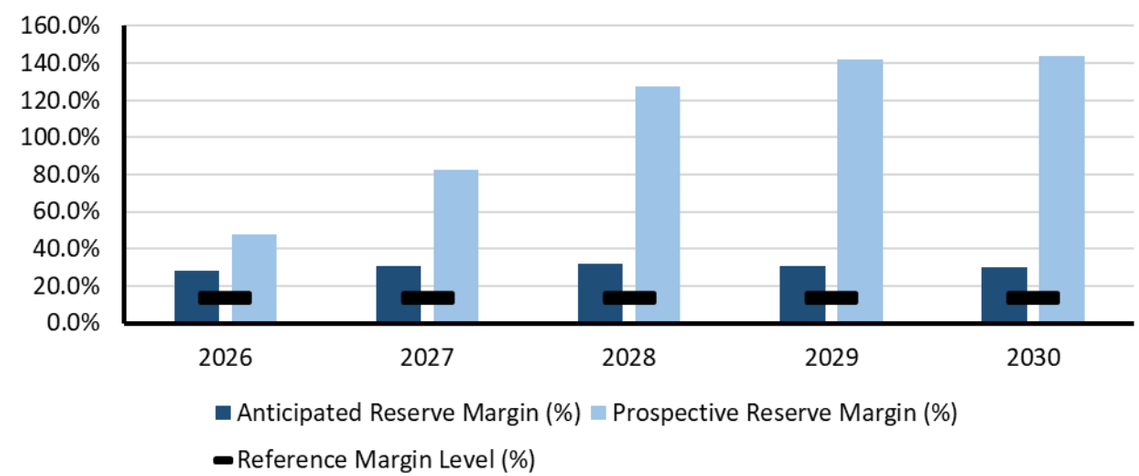


Texas RE-ERCOT

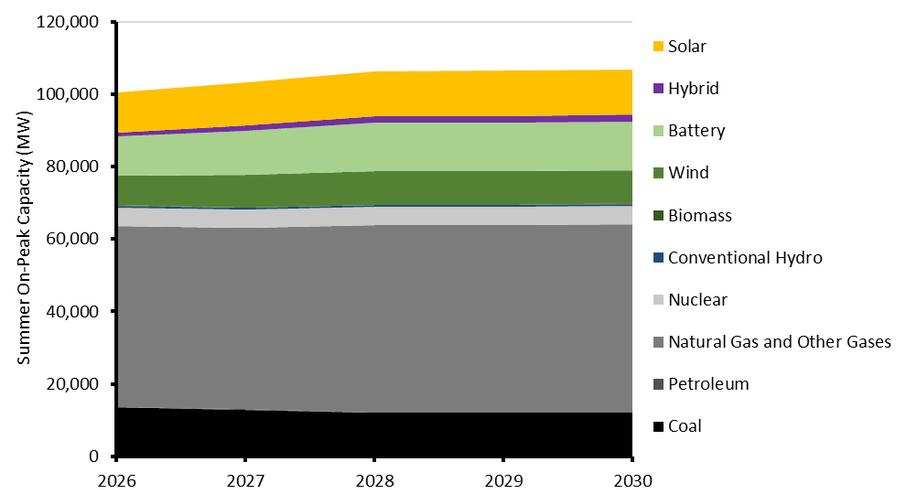
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Reliability Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	94,650	104,295	121,543	128,851	138,944	144,522	148,567	149,846	152,230	154,077
Demand Response	13,346	22,127	37,672	43,888	53,131	57,720	60,942	61,846	62,644	63,321
Net Internal Demand	81,304	82,168	83,871	84,963	85,813	86,802	87,625	88,000	89,586	90,756
Additions: Tier 1	10,377	15,216	18,527	19,037	19,037	19,037	19,037	19,037	19,037	19,037
Additions: Tier 2	15,391	42,413	79,923	95,374	98,707	99,018	99,018	99,018	99,018	99,018
Additions: Tier 3	5,022	17,546	36,405	51,080	58,217	58,217	58,463	58,463	58,463	58,463
Net Firm Capacity Transfers	508	659	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122
Existing-Certain and Net Firm Transfers	93,870	92,008	92,046	92,113	92,401	92,401	92,401	92,401	92,401	92,401
Anticipated Reserve Margin (%)	28.2%	30.5%	31.8%	30.8%	29.9%	28.4%	27.2%	26.6%	24.4%	22.8%
Prospective Reserve Margin (%)	47.9%	82.3%	127.3%	142.1%	143.9%	141.5%	139.2%	138.2%	134.0%	131.0%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Texas RE-ERCOT Highlights

- The ARM is above the 13.75% RML for all years and seasons and reflects the inclusion of provisional forecast estimates of large-load curtailment potential, applicable before and during ERCOT emergency conditions.
- ERCOT forecasts total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%.
- Texas Senate Bill 6, signed into law in June 2025, provides ERCOT with new large-load curtailment management tools and the authority to direct large loads to curtail their load both prior to and during declared energy emergency situations.
  - Offsetting the positive ARM impact of these load management programs is the switch from using historical average on-peak capacity factors to average ELCC for IBRs.
- ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026, growing to 25.2 GW by 2029, which reflects the furthest future year for reported planned commercial operations dates.
- ERCOT's 2024 Regional Transmission Plan (RTP) includes a 345 kV plan and the Texas 765 kV Strategic Transmission Expansion Plan (TX 765-kV STEP), which addresses unprecedented load growth expected by 2030.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	13,596	12,941	12,156	12,156	12,156
Coal*	13,596	12,550	11,205	11,205	11,205
Petroleum	30	30	30	30	30
Natural Gas	50,032	50,122	51,689	51,689	51,977
Natural Gas*	50,032	49,764	51,331	51,331	51,619
Biomass	131	131	131	131	131
Solar	11,049	11,923	12,305	12,534	12,534
Wind	8,303	8,900	9,215	9,219	9,219
Conventional Hydro	570	570	570	570	570
Nuclear	4,973	4,973	4,973	4,973	4,973
Hybrid	1,127	1,497	1,813	1,909	1,909
Battery	10,734	12,285	13,375	13,374	13,374
Total MW	**100,545**	**103,372**	**106,257**	**106,584**	**106,872**
Total MW*	**100,545**	102,203	104,528	104,855	105,143

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.
**Wind, solar, and battery capacities are based on their projected effective load carrying capabilities during peak load conditions.

Planning Reserve Margins

The ARM is above the 13.75% RML only for summers 2026 and 2027, and winters 2025–26 and 2026–27. The main contributing factor for lower ARMs relative to last year's LTRA is the switch from using historical average on-peak capacity factors to average ELCC for IBRs. In the case of solar, ELCCs are significantly lower than on-peak capacity factors since ELCCs reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low. Partially offsetting the reduction in solar contribution was the shift from assigning 0% on-peak capacity contribution for battery energy storage to using average ELCCs based on design duration. For example, battery storage systems with a duration of one hour or less are assigned an ELCC of 36%, whereas the ELCC for systems greater than one hour and less than two hours is 69%.

Energy Risk, Including Non-Peak Hour Risk

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at HE 9:00 p.m.—based on probabilistic capacity reserve modeling for monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. However, the large growth in battery energy storage resources and associated changes in state of charge management have mitigated the capacity reserve scarcity risk relative to previous years. For winter, risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 to 9:00 a.m.) as well as the early evening hours.

Probabilistic Assessments (NERC ProbA and Other Studies)

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	11,090	5,864	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.94	3.64
*** Provides the 2024 ProbA Results for Comparison**			

Like the 2024 ProbA Study, most risk is in the winter, and this is mainly driven by the large demand variability modeled in the winter. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year.

12x24 EUE Heat maps (months for the vertical axis, hours for the horizontal axis) for 2027 and 2029 are provided below. Note that as the numbers are given in percentages, the lower winter values in 2029 relative to 2027 do not indicate a decrease in winter risk, just a smaller portion of the annual total.

2027

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	4%	3%	2%	2%	3%	5%	8%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	7%	5%	4%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	2%	2%	2%	2%	2%	3%	4%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	4%	4%

2029

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	3%	2%	2%	2%	3%	4%	6%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	4%	4%	4%	3%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	1%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%	5%	1%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	1%	1%	1%	1%	1%	2%	2%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	2%	2%	2%	2%

Demand

ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads, comprised mostly of data centers. The breakdown of new large loads added by 2030 by customer classification is as follows:

Load Additions in the Load Forecast (MW) (Cumulative)			
Load Type	**End of Year 2 (2027)**	**End of Year 5 (2030)**	**End of Year 10 (2035)**
Data Centers	**6,700**	**23,000**	**25,000**
Cryptocurrency Mining Facilities	**4,500**	**7,500**	**8,500**
Hydrogen Electrolysis	**3,000**	**7,902**	**9,100**
Industrial Manufacturing Load	**2,800**	**7,100**	**7,600**

For 2025, the ERCOT transmission service providers (TSP) had once again reported a significantly larger-than-normal amount of contracted large loads that they asked to be included in the *2025 Long-Term Load Forecast* and *Regional Transmission Planning Study*. Due to the large amount of large-load requests for 2025, ERCOT has applied adjustment factors to these requests. ERCOT has adjusted the large-load projections provided by the TSPs based on the patterns observed by recent projects. The first adjustment was based on the average project delay of 180 days from the original project requested energization date for projects with in-service dates in 2022 through 2024. The next adjustment was applied to Data Centers. ERCOT studied requested MWs versus the peak consumption by data center site for data centers with in-service dates in 2022 through 2024. The average peak consumption per site was 49.8% of the requested MW. This factor was applied to all non-crypto data center load additions. The final adjustment used the percentage of previously filed officer letter projects with in-service dates in 2024 that have energized (55.4%). This percentage is based on percentage of loads energized.

The PUCT is developing criteria for including large loads in ERCOT's load forecasts along the lines of criteria applicable to generation projects (for example, the large-load customer has executed and securitized an interconnection agreement or meets other criteria demonstrating a firm commitment to interconnecting the load).

Demand-Side Management

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT's authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. The following table shows the total large loads and their curtailment amounts included in the "Controllable and Dispatchable Demand Response" line items.

Summer	Total LL (MW)	LL Curtailment (MW)		Winter	Total LL (MW)	LL Curtailment (MW)
2025 (S)	3864.4	1,313.9		2025-26 (W)	9112.9	8,227.7
2026 (S)	12355.4	8,853.5		2026-27 (W)	17289.8	15,909.3
2027 (S)	21665.7	17,171.5		2027-28 (W)	31590.8	29,408.9
2028 (S)	38583.3	32,716.5		2028-29 (W)	45249.3	42,298.1
2029 (S)	45681.1	38,932.6		2029-30 (W)	55533.1	51,981.4
2030 (S)	55964.9	48,175.5		2030-31 (W)	60917.9	57,010.6
2031 (S)	61349.7	52,764.3		2031-32 (W)	64863.6	60,672.7
2032 (S)	65295.4	55,985.9		2032-33 (W)	66370.5	62,017.8
2033 (S)	66802.3	56,890.6		2033-34 (W)	67764.7	63,256.0
2034 (S)	68196.5	57,688.4		2034-35 (W)	69032.1	64,373.6
2035 (S)	69463.9	58,365.6		2035-36 (W)	69805.1	65,043.3

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member Transmission and Distribution Service Providers (TDSPs) to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year time frame.

ERCOT has proposed rule changes mandated by the Texas Legislature to establish a process to collect comprehensive data from Distribution Service Providers for so called "Unregistered Distributed Generators" (primarily rooftop solar systems). The data will be collected on a substation level and will include information to be used for network modeling and analysis, including aggregate reactive power capability and status of PUCT voltage/frequency ride-through requirements.

Generation

In 2024, ERCOT received notices of suspension of operations for three gas-steam units in the San Antonio area. Reliability impact studies indicated that all three were needed to manage the South Texas Interconnection Reliability Operating Limit (IROL) established in 2024. As a result, ERCOT signed

a two-year "Reliability Must Run" (RMR) agreement with CPS energy for one of the three generators (Unit 3). This generator, as part of its RMR service obligation, would only operate when necessary to provide voltage support, stability, or management of localized transmission constraints when a market solution does not exist. ERCOT also signed a contract in June 2025 to use 15 mobile generators that are being relocated from Houston to the San Antonio area. The contract ends in March 2027 when transmission solutions are expected to be in place to offset the loss of the mothballed CPS generating units.

New rules became effective in October 2024 to improve IBR ride-through performance and monitoring and mitigation efforts. The rules were developed in response to NERC recommendations following IBR failures during system disturbances in West Texas. The new ride-through requirements align with the specifications of the updated IEEE 2800-2022 standard, which addresses the interconnection and interoperability of IBRs. As part of the new rules, IBR entities are required to maximize their IBR ride-through capabilities, which includes making software, firmware, and settings adjustments, and potentially physical modifications to ensure that they can remain connected to the grid during frequency and voltage disturbances. The rules also establish a process for investigating, reporting, and mitigating ride-through performance failures, requiring resource entities to develop mitigation plans within a defined timeline. IBR entities must meet the new requirements by December 31, 2025, or their synchronization date, subject to an extension/exemption process.

During 2024, units totaling 18.6 MW were retired, comprising a 9.6 MW biomass facility, a 7 MW wind site, and 2 MW battery storage system. So far in 2025, a 62 MW gas combined-cycle unit was retired.

Energy Storage

ERCOT expects battery energy storage capacity to reach 18.9 GW by summer 2026 (Existing and Tier 1 resource categories). The capacity grows to 25.2 GW by 2029, which reflects the furthest future year for planned commercial operations dates reported by project developers.

ERCOT is moving away from a dual to an integrated single model of an energy storage resource for operational and transmission planning studies. Under the dual approach, an energy storage resource is composed of a generator with a negative minimum power to represent consumption and a generator with a positive maximum power to represent injection. The single "integrated" generator model, along with other system enhancements for battery energy storage, is being implemented as part of ERCOT's "Real Time Co-Optimization + Battery" project, expected to be implemented by December 2025. Since each resource receives independent dispatch instructions and ancillary service deployments in the dual model approach, moving to a single integrated resource model will eliminate current performance monitoring issues. The discharging behavior for all energy storage resources is considered for peak cases in transmission planning studies. The charging behavior for all energy storage resources is considered for minimum load cases in transmission planning studies. Energy storage resources, if required to provide voltage support, need to have the reactive power capability be available at all MW levels when charging or discharging and meet the voltage ride-through requirements to remain connected to the system. To support larger penetration levels of energy storage resources, new rules have been implemented to improve state-of-charge monitoring in energy dispatch and Reliability Unit Commitment.

Capacity Transfers (Reliance on Assistance)

ERCOT has coordination plans in place with neighboring grids. These plans cover DC tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers. For its transmission planning studies, ERCOT tests the outage of each of the ERCOT-SPP DC ties, plus a contingency on top of that, to ensure no reliability issues post-contingency. There are no severe scenarios studied where multiple DC ties are assumed to be unavailable.

Transmission

ERCOT's 2024 RTP includes a 345 kV plan and a 765 kV plan, called the Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP). The 765-kV plan tackles the unprecedented load growth expected by 2030 and associated regional planning challenges and addresses existing congestion issues. TX 765-kV STEP enhances transfer capability by an additional 600 to 3,000 MW across various scenarios evaluated in the analysis and would also increase the West Texas export stability constraints. The 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers. Overall, 274 reliability projects were identified in the 2024 RTP's 345 kV plan to address all reliability violations compared with 173 projects in the 2023 RTP, 89 projects in the 2022 RTP, 67 projects in the 2021 RTP, and 50 projects in the 2020 RTP. This upward trend reflects grid infrastructure needed to support rapidly growing power demands and an evolving generation resource mix.

ERCOT is adopting changes to its planning processes to address the long-term transmission challenges. Examples of the major changes include establishment of a new congestion cost savings test for economic project evaluation, establishment of resiliency criteria for the ERCOT region, and development of new multi-value criteria to address the process for determining whether a project that addresses a resiliency issue provides sufficient benefit balanced with economic savings or reliability benefits.

Reliability Issues

There are several reliability concerns associated with the rapid growth in large loads:

Loss of Load: Due to the amount of large electronic-based load projected to energize in upcoming years (mainly from cryptocurrency mining facilities), ERCOT is concerned that potentially thousands of megawatts of load can instantly drop or switch to backup generation during normally cleared system faults, thereby posing significant risks to system reliability. To address this concern, ERCOT has proposed a change to its Reliability Performance Criteria to limit load loss for any single contingency and to specify how loss of load is calculated for this criterion. ERCOT recently completed a Load Loss Threshold Analysis that indicates that the load loss should be limited to 2,600 MW.

Load Forecasting Challenges: The flexible operation of large loads also presents challenges for accurate load forecasting and monitoring. ERCOT has observed increasing errors in its load forecasts, which is problematic during extreme or unusual operating days when having an accurate forecast is most critical for maintaining reliability. New approved rules include standards for the identification and classification of a site with an aggregate peak demand of 25 MW or more at a common substation in ERCOT's Network Operations Model. Such information will provide ERCOT visibility of the locations of these loads for operational, modeling, and planning purposes.

Potential Subsynchronous Oscillation Vulnerabilities: Large loads, particularly those with high reactive power consumption, can cause subsynchronous oscillation (SSO) that can damage generation and other equipment and ultimately destabilize the grid. This vulnerability is highest in areas with a weak grid, such as West Texas. To address SSO issues, ERCOT is implementing new rules that require SSO vulnerability assessments for large-load customers seeking grid interconnection as well as for transmission projects.

Need for a Large Load Interconnection Study Process: ERCOT identified the need for a Large Load Interconnection Study (LLIS) process several years ago due to the emerging reliability impacts. An interim process was estimated in March 2022. A final interconnection process was approved by the PUCT in May 2025.

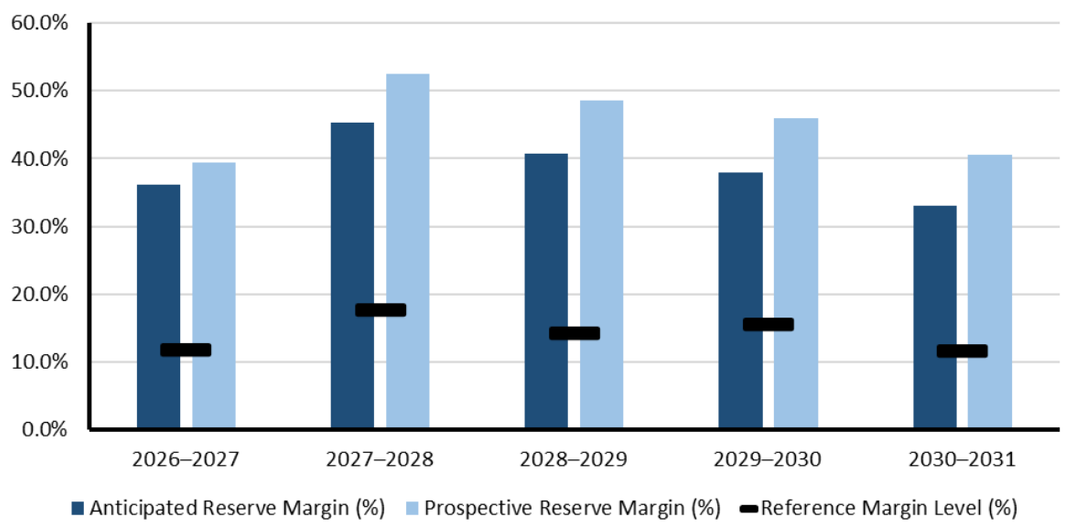


WECC-Alberta

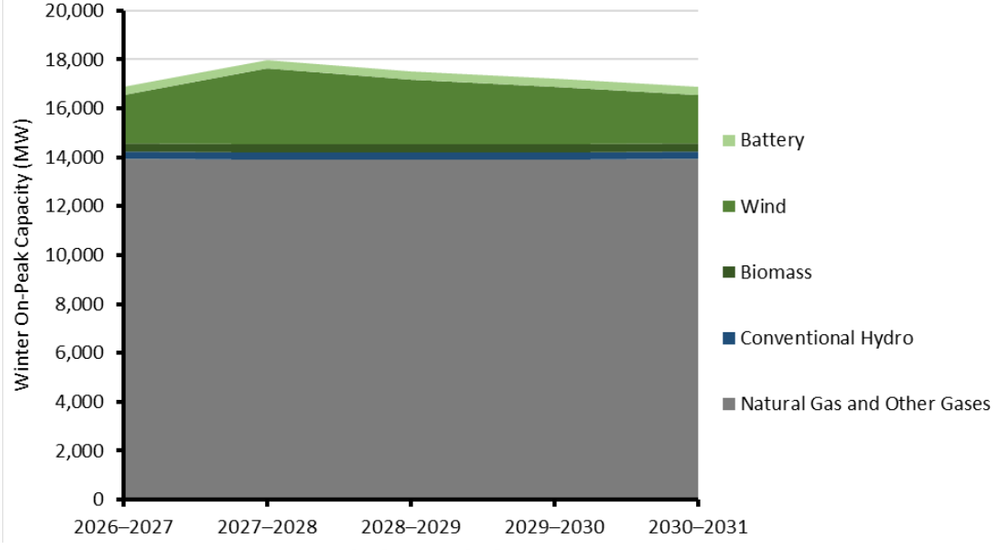
WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and Reliability Coordinator responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Additions: Tier 1	209	209	209	209	209	209	209	209	209	209
Additions: Tier 2	393	889	983	1,009	959	1,009	921	971	971	971
Additions: Tier 3	392	658	917	1,297	1,334	1,631	1,635	1,751	1,751	1,751
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	16,764	17,856	17,394	17,074	16,764	17,074	16,502	16,820	16,820	16,820
Anticipated Reserve Margin (%)	36.2%	45.3%	40.7%	38.0%	33.0%	34.7%	29.0%	31.1%	30.2%	26.4%
Prospective Reserve Margin (%)	39.3%	52.4%	48.6%	46.0%	40.5%	42.6%	36.1%	38.5%	37.7%	33.6%
Reference Margin Level (%)	11.8%	17.6%	14.3%	15.6%	11.6%	15.2%	12.2%	14.3%	13.9%	13.5%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Alberta Highlights

- WECC-Alberta's ARM does not fall below the RML during the 2025–2035 time frame.
- WECC-Alberta's total electricity demand is projected to grow by 10% over the next 10 years. Summer peak hour demand is projected to grow by 7%, and winter peak hour demand is projected to grow by 11% over the same period.
- Alberta is anticipated to add 556 MW of Tier 1 gas, solar, and battery resources over the next 10 years. Alberta's thermal power generation fleet is aging, and significant additions of Tier 2 and 3 variable renewable energy resources are being proposed to make up for forthcoming thermal retirements while meeting Alberta's 30% renewable by 2030 policy requirement. On top of the 250 MW of existing storage, 88 MW are anticipated Tier 1 and 370 MW are Tier 2 additions over the next 10 years. Still, rapid declines in solar and wind output could cause ramping issues in the future and require the use of contingent reserves and assistance from the NWPP Reserve Sharing Group.
- AESO has recently added two transmission lines to its system to increase reliability and integrate fossil-fired generation additions.
- Under a different set of assumptions and with a different vintage of data from the LTRA, the NERC ITCS for Canada concluded that WECC-Alberta may have winter energy deficiencies that could be alleviated by increased transfer capabilities.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	13,932	13,908	13,890	13,900	13,932
Biomass	336	336	335	336	336
Wind	2,000	3,109	2,665	2,327	2,000
Conventional Hydro	293	301	301	310	293
Other	81	81	81	81	81
Battery	330	330	329	330	330
Total MW	16,973	18,065	17,602	17,283	16,973

WECC-Alberta Assessment

Planning Reserve Margins
WECC-Alberta's ARM does not fall below the RML during the 2025-2035 time frame. WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1 day in 10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Canada Clean Electricity Regulations (CER) were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Alberta has recently entered into an agreement with the Canadian federal government to pursue alternative policies to achieve a net-zero power grid by 2050.

Energy Risk, Including Non-Peak Hour Risk
AESO uses an hourly probabilistic model to quantify uncertainties around unit availability, dispatch economics, load variability, and weather impact on load and generation in operational time frames.

ProbA Results

Alberta does not show any LOLH or EUE in 2027 or 2029 and therefore does not have any further reporting or visualizations.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*** Provides the 2024 ProbA Results for Comparison**			

Demand
Alberta's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 7% and winter peak hour demand is projected to grow 11% over the same period. The primary driver for demand growth in Alberta is transportation electrification. Large-load additions in the forecast total 80 MW over the next five years and 105 MW through 2035. Additional large loads that may materialize and are not included in the forecast amount to 1,600 MW by 2030 and 2,100 by 2035.

Seasonally, the region is becoming more dual-peaking with summers almost matching winters.

Demand-Side Management
AESO factors in approximately 250 MW of DSM in its load forecast and this is projected to remain steady across the 10-year assessment period.

Generation
Alberta is anticipated to add 556 MW (nameplate capacity) of Tier 1 gas, solar, and battery resources over the next 10 years. Tier 2 additions include nearly 5 GW of gas, solar, wind and batteries and Tier 3 additions include just over 5 GW of gas, solar, wind, conventional hydro, and batteries. Operational and planning issues related to generation in WECC-Alberta include the following:

- Aging Thermal Resource Fleet: There is ongoing analysis of potentially mothballing aging coal-to-gas boilers. Alberta has five natural gas steam sites over 35 years old, which total 1,745 MW of capacity. Alberta shows significant additions of Tier 2 and Tier 3 solar and wind to make up the difference. Supply shortfalls are addressed using the protocols in AESO's ISO Rules. These protocols include directives such as instructing available assets and long-lead-time assets to deliver energy up to their maximum capability, calling upon DR, and maximizing import capability.
- Solar and Wind Variability: Rapid decline in solar and wind output coupled with off-line thermal resources can create situations in which thermal resources cannot be ramped up in time to counter the loss of renewable generation. The use of contingency reserves coupled with a subsequent grid alert declaration to receive assistance from the NWPP Reserve Sharing Group (NWPPRSG) are options for addressing these situations.
- Electric-Gas Coordination: As a part of WECC's load and resources data request, members were asked to provide a conservative estimate of the percentage of natural gas generating capacity that is likely to have firm supply for 2025 and 2030 for both the summer and winter season. Results indicated that all natural-gas-fired generators connected to AESO's system are fueled through firm gas supply contracts during both the summer and winter seasons but do not report any dual-fuel capacity. To enhance operational reliability of natural gas fuel supplies for the province, Alberta's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events impact the gas supply and transportation system. There is frequent communication between system operators regarding gas resources

that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

- Resource Portfolio, Clean Electricity, and Development Policies: The Canadian province of Alberta is required to ensure its electricity supply is 30% renewable by 2030. Alberta has also issued a ban on renewable energy project development on prime agricultural land and a buffer zone around pristine views, both of which could limit siting for wind and solar. This followed a temporary moratorium from August 2023 to March 2024 on new renewable approvals, creating investment uncertainty. In January 2025, Alberta lifted a previous 2022 moratorium on coal exploration, reopening 190,000 hectares of land to new coal development.

Energy Storage

In addition to the 250 MW of existing energy storage in Alberta, 88 MW are anticipated Tier 1 additions, and 370 MW are projected Tier 2 additions of energy storage over the next 10 years. Storage in the west is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

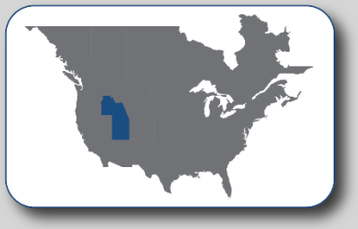
Energy Transfers

According to the NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the Alberta transmission planning region from all its neighbors, including dc-only interties, is 1,096 MW in 2024 Summer and 1,005 MW in 2024–25 Winter. These values translate to approximately 10% of peak summer load and 9% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Montana (see WECC-Northwest) and British Columbia (see WECC-British Columbia).

The ITCS for Canada further showed that WECC-Alberta may have winter energy deficiencies that can be alleviated with increased transfer capabilities.

Transmission

In 2024, Alberta added two transmission lines for fossil-fired integration. The reported primary driver for transmission expansion in Alberta is reliability.

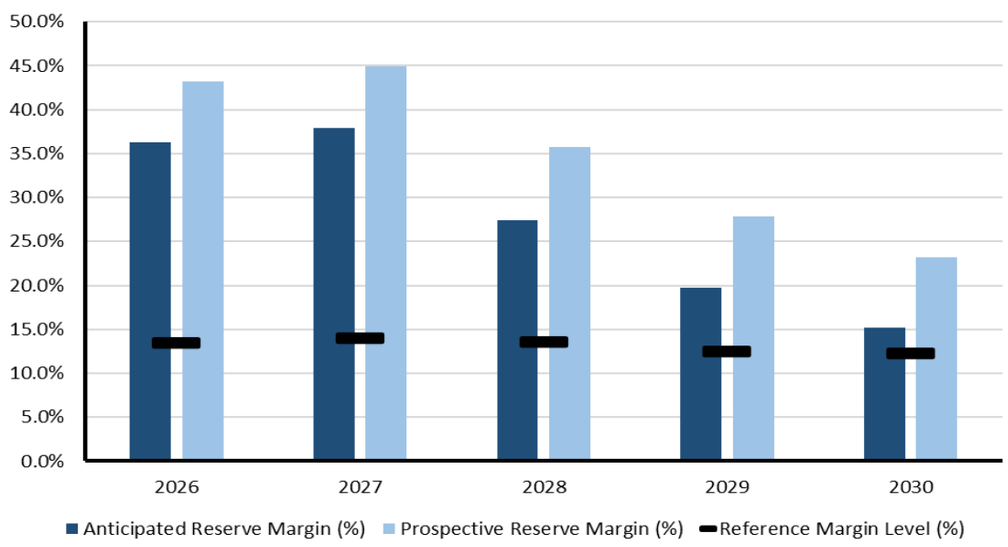


WECC-Basin

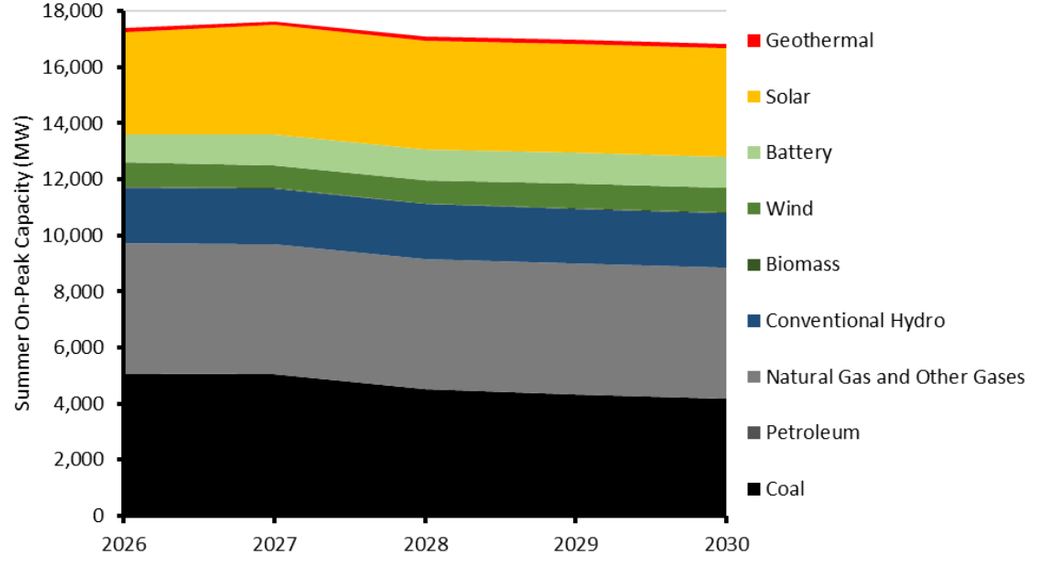
WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,794	15,326	16,012	16,396	16,762	17,099	17,202	17,268	17,344	17,467
Demand Response	670	670	670	670	670	670	670	670	670	670
Net Internal Demand	14,124	14,656	15,342	15,726	16,092	16,429	16,532	16,598	16,674	16,797
Additions: Tier 1	2,125	2,453	2,453	2,466	2,466	2,466	2,466	2,453	2,466	2,466
Additions: Tier 2	973	1,018	1,270	1,279	1,279	1,279	1,279	1,270	1,279	1,279
Additions: Tier 3	127	1,162	2,024	2,616	4,209	4,726	5,665	6,203	6,332	6,332
Net Capacity Transfers (WECC Model)	1,822	2,545	2,420	1,820	1,698	1,400	1,400	1,400	1,400	1,400
Existing-Certain and Net Transfers	17,125	17,763	17,097	16,357	16,071	15,736	15,729	15,315	15,288	15,280
Anticipated Reserve Margin (%)	36.3%	37.9%	27.4%	19.7%	15.2%	10.8%	10.1%	7.1%	6.5%	5.7%
Prospective Reserve Margin (%)	43.2%	44.9%	35.7%	27.8%	23.1%	18.6%	17.8%	14.7%	14.2%	13.3%
Reference Margin Level (%)	13.5%	14.0%	13.6%	12.4%	12.3%	12.1%	12.1%	12.5%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Basin Highlights

- The ARM does not fall below the RML during the 2025–2035 time frame. IPCO and PACE participate in the Western Resource Adequacy Program (WRAP).
- The Basin subregion shows three LOLH in 2027 totaling approximately 3 MWh of EUE in June and July at hours beginning 18:00 and 19:00. In 2029, the subregion shows 310 LOLH totaling approximately 200,892 MWh of unserved energy. Over 90% of the EUE occurs between the hours of 17:00–22:00 from June to September.
- For 2027 and 2029, the peak hour is projected to occur in July at hour beginning 15:00.
- The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

WECC-Basin Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	5,068	5,041	4,508	4,326	4,177
Petroleum	5	5	5	5	5
Natural Gas	4,655	4,634	4,634	4,655	4,655
Biomass	31	31	31	31	31
Solar	3,668	3,899	3,899	3,884	3,884
Wind	900	826	826	897	882
Geothermal	139	139	139	139	139
Conventional Hydro	1,962	1,976	1,968	1,954	1,954
Other	31	31	31	19	19
Battery	967	1,090	1,090	1,092	1,092
Total MW	**17,428**	**17,672**	**17,130**	**17,003**	**16,839**

WECC-Basin Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2026–2035 time frame. The Idaho Power and PacificCorp East balancing areas both participate in WRAP, the first regional reliability planning and compliance program in the West.

Energy Assessment, Including Non-Peak Hour Risk

WECC performs a probabilistic resource adequacy analysis using the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC's internally developed modeling tool that performs energy based ProbAs that support NERC's LTRA and seasonal assessments, as well as WECC's Western Assessment of Resource Adequacy (WARA).

Although the WECC-Basin assessment area's ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs after 2027, unserved energy and load-loss increase in the ProbA results. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

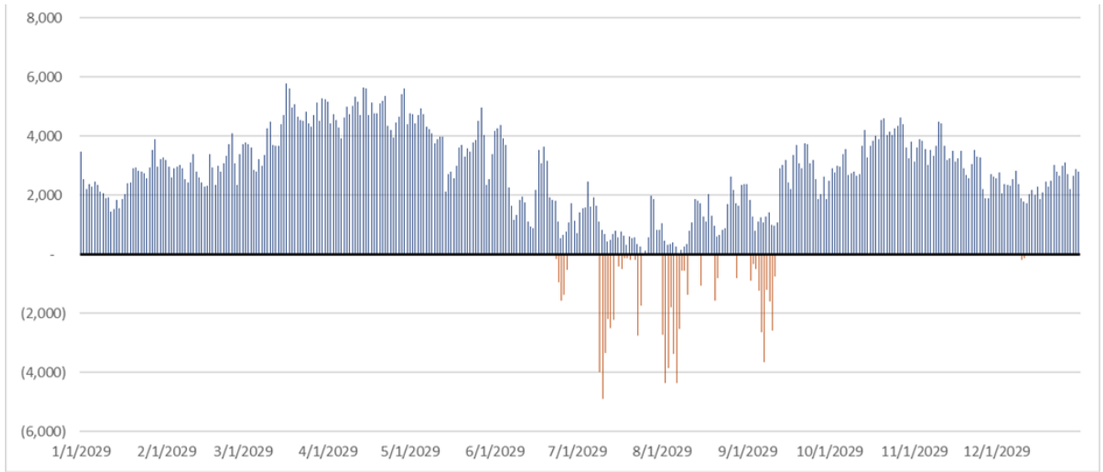
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2250.70
LOLH (hours per Year)	N/A	3.00	310.00
*** No prior results as the assessment area is new for the 2025 LTRA.**			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. In the ProbA results illustrated in the following heat map figure, risk is most concentrated to the month of peak demand (June) and the hours around sunset as solar output declines. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime.

Basin - 2027		Months												Basin - 2029		Months											
Existing + Tier 1		1	2	3	4	5	6	7	8	9	10	11	12	Existing + Tier 1		1	2	3	4	5	6	7	8	9	10	11	12
Hour Beginning	0	0	0	0	0	0	0	0	0	0	0	0	0	Hour Beginning	0	0	0	0	0	0	0	0	0	0	0	0	0
	1	0	0	0	0	0	0	0	0	0	0	0	0		1	0	0	0	0	0	0	0	0	0	0	0	0
	2	0	0	0	0	0	0	0	0	0	0	0	0		2	0	0	0	0	0	0	0	0	0	0	0	0
	3	0	0	0	0	0	0	0	0	0	0	0	0		3	0	0	0	0	0	0	0	0	0	0	0	0
	4	0	0	0	0	0	0	0	0	0	0	0	0		4	0	0	0	0	0	0	0	0	0	0	0	0
	5	0	0	0	0	0	0	0	0	0	0	0	0		5	0	0	0	0	0	0	0	0	0	0	0	0
	6	0	0	0	0	0	0	0	0	0	0	0	0		6	0	0	0	0	0	0	0	0	0	0	0	1
	7	0	0	0	0	0	0	0	0	0	0	0	0		7	0	0	0	0	0	0	0	1	0	0	0	2
	8	0	0	0	0	0	0	0	0	0	0	0	0		8	0	0	0	0	0	0	0	1	0	0	0	2
	9	0	0	0	0	0	0	0	0	0	0	0	0		9	0	0	0	0	0	0	0	0	0	0	0	0
	10	0	0	0	0	0	0	0	0	0	0	0	0		10	0	0	0	0	0	0	0	0	0	0	0	0
	11	0	0	0	0	0	0	0	0	0	0	0	0		11	0	0	0	0	0	0	2	0	0	0	0	0
	12	0	0	0	0	0	0	0	0	0	0	0	0		12	0	0	0	0	0	0	8	1	0	0	0	0
	13	0	0	0	0	0	0	0	0	0	0	0	0		13	0	0	0	0	0	1	9	2	0	0	0	0
	14	0	0	0	0	0	0	0	0	0	0	0	0		14	0	0	0	0	0	2	8	2	1	0	0	0
	15	0	0	0	0	0	0	0	0	0	0	0	0		15	0	0	0	0	0	3	8	3	1	0	0	0
	16	0	0	0	0	0	0	0	0	0	0	0	0		16	0	0	0	0	0	2	8	4	6	0	0	3
	17	0	0	0	0	0	0	0	0	0	0	0	0		17	2	0	0	0	0	4	11	14	8	0	0	5
	18	0	0	0	0	0	1	0	0	0	0	0	0		18	0	0	0	0	0	6	16	20	12	0	0	4
	19	0	0	0	0	0	1	1	0	0	0	0	0		19	0	0	0	0	0	7	17	22	9	0	0	3
	20	0	0	0	0	0	0	0	0	0	0	0	0		20	0	0	0	0	0	5	16	13	8	0	0	2
	21	0	0	0	0	0	0	0	0	0	0	0	0		21	0	0	0	0	0	0	7	9	1	0	0	0
	22	0	0	0	0	0	0	0	0	0	0	0	0		22	0	0	0	0	0	0	0	5	0	0	0	0
	23	0	0	0	0	0	0	0	0	0	0	0	0		23	0	0	0	0	0	0	0	3	0	0	0	0

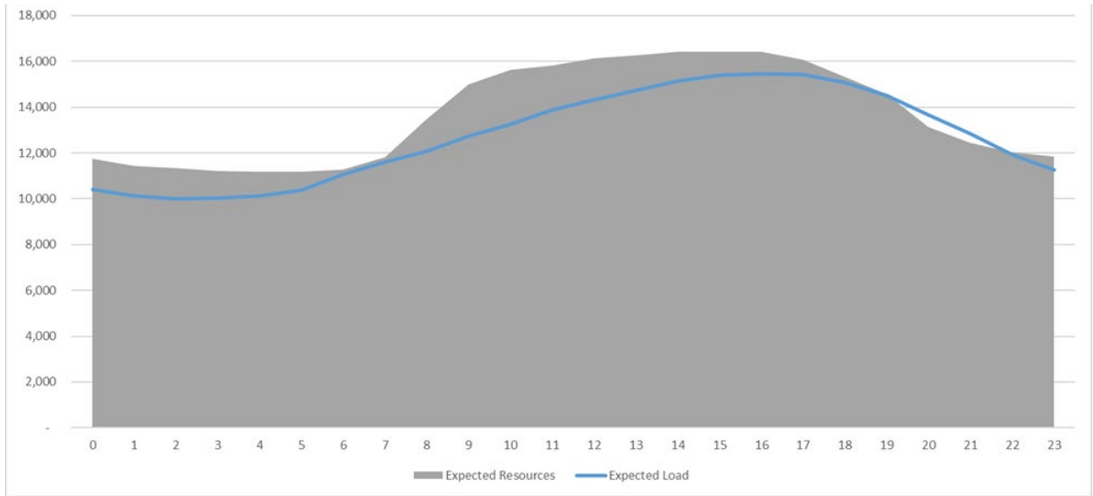
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Basin Assessment Area in 2027 and 2029

In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Basin has excess energy that can be transferred to neighboring areas. During peak summer months, however, more of WECC-Basin's resources are needed for its own internal demand and, at times, energy deficits that must be met by importing energy from neighbors can exceed 4,000 MW.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. LOLH occurs at hour of 17:00 to 21:00 in 2029. This coincides with the evening solar down ramp and the persistence of elevated demand after the peak hour. The profile for the 2027 study year is similar but limited to the 18:00 to 19:00 hour. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Basin assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual growth rate for Basin is 2.5%. The primary drivers are data centers and semiconductor manufacturing. Large-load additions in the forecast are 1,223 MW through 2035.

Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows the utility to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year-to-year based on factors such as the availability of water and program parameters. PacifiCorp states in its most recent IRP that it plans to reach more than 1,100 MW of dispatchable DR by 2042, a 21% increase from its previous plan. The company's dispatchable DR programs include residential and small commercial air-conditioner load control programs, irrigation load management programs, and approximately 200 MW of evergreen interruptible contracts.

Distributed Energy Resources

BTM DER impacts are reflected in the demand forecasts (net of the DERs). BAs did not report a forecast for BTM resources.

Generation

Operational and planning issues related to generation in WECC-Basin include the following:

- **Aging Thermal Resource Fleet:** An aging thermal resource fleet is a year-round concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. Maintenance is planned years in advance and avoided during summer peak season as much as possible. Quarterly evaluations are done to adjust maintenance schedules as needed.
- **Gas Fleet Derates:** During the winter, gas resources may be derated during extreme cold and precipitation events for equipment issues such as snow-clogged inlet filters. This issue is remedied by monitoring filters and changing them out as needed.
- **Hydro Variability:** Hydro resources in this subregion are subject to seasonal and multi-year fluctuations in water supply. This is a year-round concern that requires persistent monitoring. Regular updates to near-term hydro forecasts ensure system operators can be ready for a range of potential hydro output.
- **Solar Variability:** As the solar capacity in this subregion grows, solar ramps are becoming a concern on summer evenings. Large declines in solar output require the dispatch of flexible resources to meet demand. In addition, during the winter solar generation tends to be significantly lower. BESS that typically charge from solar must charge from other resources. Wind and solar forecasts are used to estimate energy availability to serve load versus the amount available for BESS charging, and other resources are dispatched accordingly.
- **Wind Variability:** Particularly during the winter, the timing and volume of wind generation can vary significantly between forecasts and actuals. This is due to the unpredictable behavior of winter storms that may overspeed turbines, or cold temperatures mixed with moisture that may result in the icing of turbine blades.

Electric-Gas Coordination

Electric-gas coordination in long-term planning studies is considered for at least one Basin entity. For integrated resource planning assumptions, Resource Planners reach out to gas traders to confirm pipeline capability to serve existing and future generating asset needs. Gas supply constraints are not explicitly modeled but are inherently reflected in the GADs data used to develop long-term models.

Maintaining gas supplier diversity is one strategy implemented to reduce the risk of fuel shortages and delivery issues in this subregion. In addition, at least one entity in this subregion participates in the Northwest Mutual Assistance Agreement (NWMAA). This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving those resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

Idaho Power serves ~63% of the state's electricity load and is targeting 100% clean electricity by 2045; Idaho has no state Renewable Portfolio Standard (RPS) or other clean energy target. Utah has enacted a voluntary renewable portfolio goal of 20% renewable energy by 2025. As of 2023, 15.5% of electricity generated in the state was renewable, putting the state on a path to meet the goal.

Transmission

PacifiCorp's Energy Gateway Transmission Plan addresses future transmission requirements necessary to serve PacifiCorp's Network Load customer needs. In total, the Energy Gateway Transmission plan, initiated in May 2007, adds approximately 2,000 miles of new transmission lines. Segments A, B, C, F, G and parts of Segment D have been completed. Segment D.3 Bridger/Anticline to Populus has a planned in-service date of 2034; Segment E Populus to Hemingway is beyond the 10-year planning horizon.

The 500 kV Boardman to Hemingway transmission line was first proposed in 2007 and has faced multiple delays. Now, as a joint project between Idaho Power and PacifiCorp (represented as Segment H in PacifiCorp's Energy Gateway transmission plan), the companies intend to break ground this year, with a planned in-service date of 2027. This ~295-mile 500 kV transmission line provides ~1,000 MW of bidirectional capacity increase between the Northwest and Idaho.

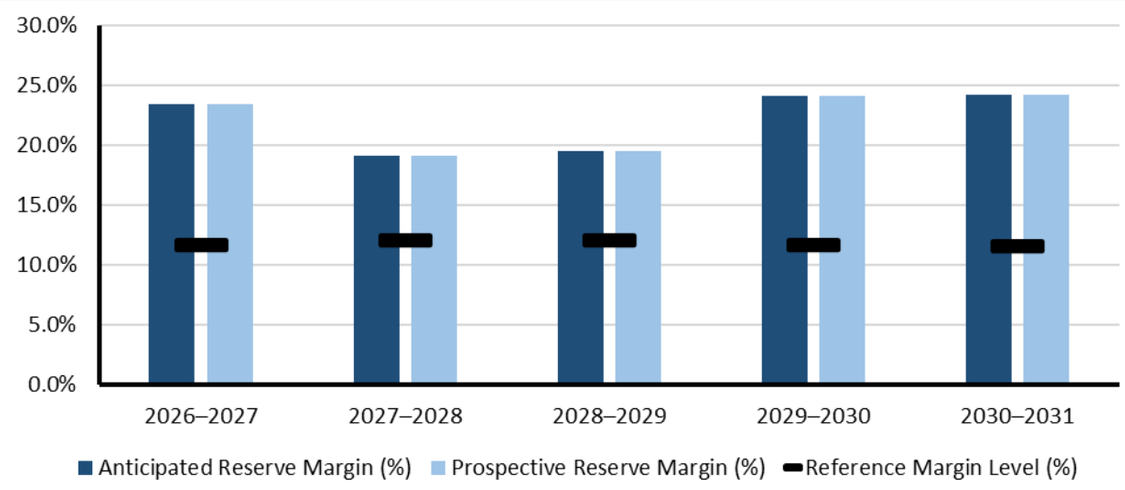


WECC-British Columbia

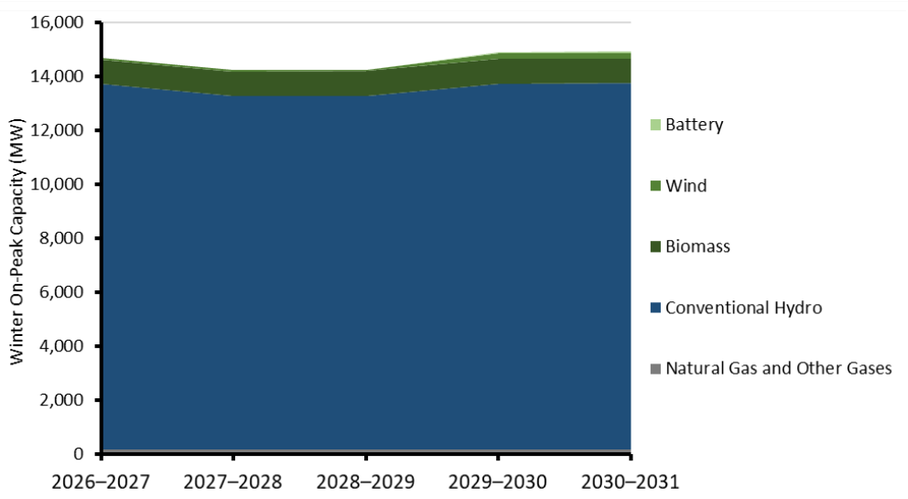
WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and Reliability Coordinator for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia Bulk Electric System and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Additions: Tier 1	636	620	625	850	863	863	863	814	863	863
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	381	369	381	381
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	14,072	13,638	13,638	14,072	14,072	14,072	14,072	13,638	14,072	14,072
Anticipated Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Prospective Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Reference Margin Level (%)	11.7%	12.1%	12.1%	11.6%	11.6%	11.6%	11.5%	11.9%	11.5%	11.4%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-British Columbia Highlights

- WECC-British Columbia's anticipated reserve margin does not fall below the RML during the 2025–2035 timeframe.
- British Columbia's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period.
- British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Hydro variability is the biggest operational issue related to generation in WECC-British Columbia.
- BC Hydro's most recent 10-year capital plan allocates $36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	170	170	170	170	170
Biomass	900	903	903	900	900
Wind	73	59	59	222	222
Conventional Hydro	13,544	13,104	13,109	13,560	13,573
Other	22	22	22	22	22
Battery	0	0	0	49	49
Total MW	14,708	14,258	14,263	14,922	14,935

WECC-British Columbia Assessment

Planning Reserve Margins

BC Hydro has used the one-day-in-10-years LOLE standard since 1975. Using a probabilistic model, BC Hydro concluded in its updated 2021 IRP that a 12% PRM of dependable generating capacity was required to ensure system resource adequacy. WECC-British Columbia's ARM does not fall below the RML during the 2025–2035 time frame.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Clean Electricity Regulations were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Provincial policies in BC that might affect resource planning and procurement include the Renewable Energy Projects Act (May 2025), (which streamlines permitting and grants the BC Energy Regulator broader approval powers for wind, solar, and transmission projects) and the BC Clean Power Action Plan (which aims to double clean electricity supply by 2050 and includes a new biennial procurement cycle for renewable resources).

BC Hydro is included in the Powerex footprint in WRAP. The WRAP defines an adequate reserve margin for its footprint for an 18-month forward period based on a loss of load expectation reliability threshold of one event day in 10 years. WRAP uses an ELCC methodology to determine capacity contribution in its analysis. The WRAP is a non-binding program for Winter 2025–26 but is currently planned to transition to a fully binding program with deficiency charges sometime in 2027. For 2025–2026 Winter, monthly PRMs for the Northwest WRAP subregion (called Mid-Columbia) range between 11.7% and 27.2%. For 2026 Summer, a PRM range between 14.2% and 22.3% is reported.

Energy Assessment, including non-peak hour risk

ProbA Results

British Columbia does not show any LOLH or EUE in 2027 or 2029.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

British Columbia did not have LOLH in 2027 or 2029; therefore, no additional reporting or visualizations are provided.

Demand

British Columbia's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period. The primary driver for demand growth in British Columbia is natural gas processing. Significant, but uncertain, effects on demand are also expected because of commercial and residential electrification and simultaneous advances in EE in those two sectors.

Distributed Energy Resources

BC Hydro has a net metering program. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

With its abundant hydro, British Columbia is already approximately 95% carbon free. The CleanBC Roadmap states, "By 2030, BC will phase out BC Hydro's last gas-powered facility so the electricity we make is 100% clean."

British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Tier 3 additions include 500 MW of conventional hydro.

Hydro variability is the main operational and planning issue related to generation in WECC-British Columbia. Over 80% of British Columbia's capacity is comprised of hydro resources, making hydro variability a concern year-round. While parts of British Columbia remain in drought classification as of the end of October 2025, many of the province's basins have recovered and conditions are now better for this time of year than in the prior two years. Drought indices for 2026–2027 remain dependent on this year's snowpack accumulation and subsequent seasonal rain. At this time, it is too soon to forecast whether drought conditions will persist or continue easing into next season for the BC Hydro integrated system. Power imports from the United States to British Columbia assist in maintaining water storage levels. More than a fifth of the power in the province was imported from the United States in 2024. Increasing electrification trends coupled with potential continued drought conditions may exacerbate the need for imports to the region in the future.

As BC is working to phase out its last natural-gas-fired power generation units over the next five years, electric-gas coordination issues are not anticipated for power supply. However, BC's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to each other when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

Energy Storage

BC Hydro is expected to add 50 MW of Tier 1 battery energy storage over the next 10 years. Battery storage in the West is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the British Columbia transmission planning regions from all its neighbors is 2,897 MW in 2024 Summer and 3,078 MW in 2024/25 Winter. These values translate to approximately 31% of peak summer load and 27% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta).

Transmission

BC Hydro's most recent 10-Year Capital Plan allocates $36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets. These changes are expected to shorten development lead-times, boost renewable energy procurement, and enhance grid infrastructure planning.

Reliability Issues

Congestion of the transmission systems supplying high-growth areas of the Lower Mainland and Vancouver Island could be a potential future emerging reliability issue. Load growth due to electrification, expected population increases, and industrial expansion could couple with increased variability in load caused by extreme weather, wildfires, atmospheric rivers, and heat waves or cold snaps, to add stress to the transmission network. Lastly, aging infrastructure could add to higher forced outage risk if supply chain disruptions create project delays, as has been occurring across the Western Interconnection in recent years.

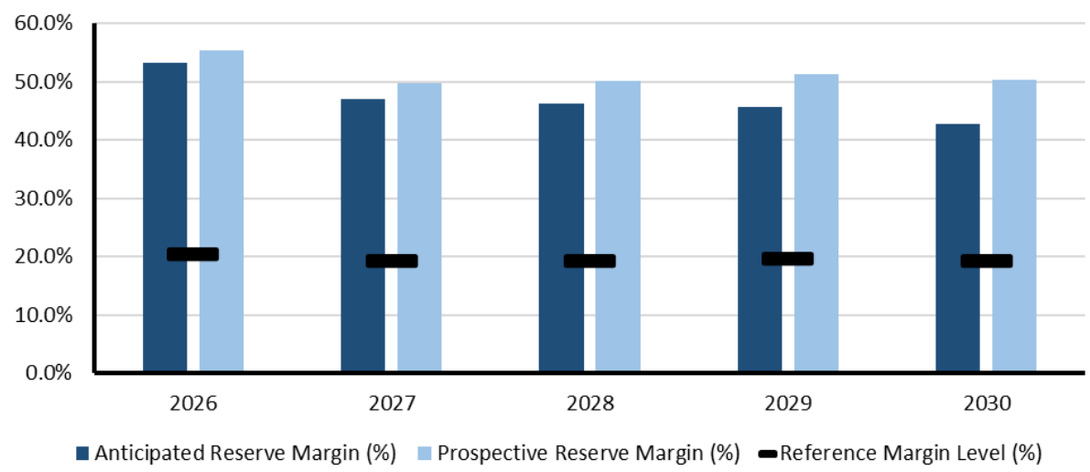


WECC-California

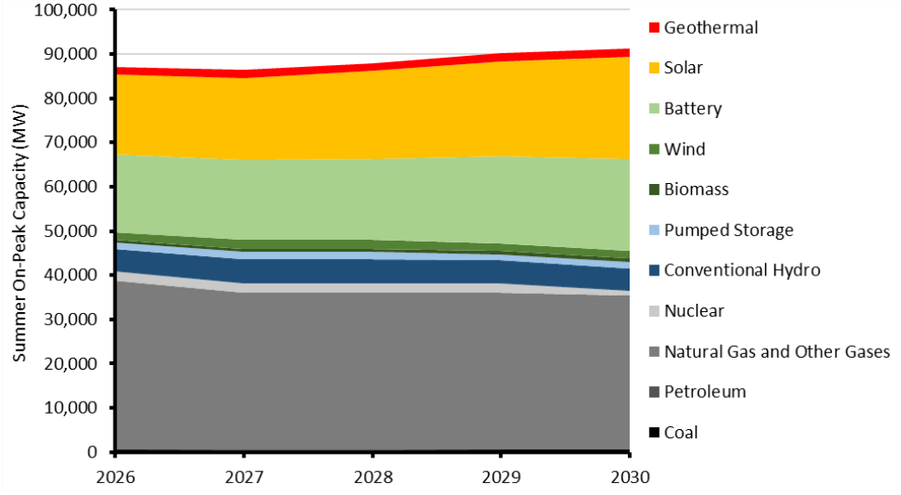
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	58,165	60,060	61,547	63,261	65,221	66,879	68,315	69,759	71,373	73,017
Demand Response	756	764	775	783	795	799	812	823	836	836
Net Internal Demand	57,409	59,296	60,772	62,478	64,426	66,079	67,504	68,936	70,537	72,182
Additions: Tier 1	11,558	13,202	14,765	17,206	19,945	19,945	21,532	22,541	23,771	25,622
Additions: Tier 2	1,288	1,552	2,388	3,489	4,974	4,974	6,509	8,475	9,208	9,244
Additions: Tier 3	10	10	10	10	557	557	557	562	557	557
Net Capacity Transfers (WECC Model)	561	583	651	639	541	234	310	314	298	287
Existing-Certain and Net Transfers	76,371	73,982	74,050	73,773	71,969	70,585	70,661	70,925	70,649	70,613
Anticipated Reserve Margin (%)	53.2%	47.0%	46.1%	45.6%	42.7%	37.0%	36.6%	35.6%	33.9%	33.3%
Prospective Reserve Margin (%)	55.4%	49.6%	50.1%	51.2%	50.4%	44.5%	46.2%	47.9%	46.9%	46.1%
Reference Margin Level (%)	20.3%	19.2%	19.3%	19.7%	19.3%	19.1%	18.9%	17.8%	18.3%	18.0%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-California Highlights

- The ARM does not fall below the RML. Further, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The California Public Utilities Commission (CPUC) recently increased the PRM requirement for 2026 and 2027 from 17% to 18%. CPUC's ruling also maintains procurement targets that provide additional summer reliability resources by ordering IOUs to procure resources of 1,260 to 2,300 MW for the months of June through October in 2026 and 2027.

WECC-California Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	466	466	466	466	466
Coal*	16	16	16	16	16
Petroleum	103	103	103	103	103
Natural Gas	38,144	35,507	35,507	35,468	34,837
Natural Gas*	38,144	34,994	34,994	35,468	34,837
Biomass	734	745	749	749	749
Solar	18,126	18,574	19,936	21,506	23,065
Wind	1,643	1,991	2,000	1,650	1,650
Geothermal	1,809	1,808	1,808	1,809	1,809
Conventional Hydro	5,112	5,426	5,426	5,112	5,112
Pumped Storage	1,401	1,549	1,549	1,401	1,401
Nuclear	2,152	2,151	2,151	2,152	1,076
Other	194	194	194	194	194
Battery	17,486	18,088	18,275	19,731	20,911
Total MW	87,368	86,601	88,164	90,340	91,372
Total MW*	86,918	85,637	87,200	89,890	90,922

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

WECC-California Assessment

Planning Reserve Margins
The ARM does not fall below the RML. The California Public Utilities Commission (PUC) recently released a PRM increase for 2026 and 2027 from 17% to 18%. The ruling also increases the PRM procurement target from 1,260 to 2,300 MW for the months of June through October for 2026 and 2027 (divided across the IOUs). Note, the CPUC's reserve margins are not used in WECC's methodology for the LTRA.

Energy Assessment, including non-peak hour risk
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results
The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

For 2027 and 2029, the peak hour is projected to occur in early September at hour beginning 16:00. California does not show any LOLH or EUE in either 2027 or 2029. No risk period visualizations are included for this subregion as there were no identified risk hours.

Demand
Average annual demand growth rate for WECC-CA is 2.4%. The primary drivers are transportation electrification and incremental load for extreme heat events. Large-load additions in the forecast are 4,993 MW through 2035.

Demand-Side Management
DR accounted for about 2.6% (1,400 MW) of total system resource adequacy capacity in the summer of 2024 compared to about 3 to 4% in the previous four summers. This drop is mainly due to a change in CPUC rules removing the PRM and transmission adders totaling over 11% previously applied to DR capacity.

DR was supplied by CPUC-regulated utility programs, non-utility third-party programs, and non-CPUC jurisdictional load-serving entities (municipal utilities, etc.). Utility DR accounts for about 76% of DR used to meet resource adequacy requirements. About 85% of this capacity was bid into the real-time market during the most critical hours of summer 2024. When dispatched, this category reported curtailing about 81% of scheduled load reductions.

Non-utility (third party) DR accounts for about 18% of DR used as resource adequacy capacity requirements, with actual load reductions of about 54% of scheduled. However, during some hours, this sector exceeded the scheduled level.

Non-CPUC jurisdictional load serving entities (municipal utilities, etc.) utilize an average of about 75 MW of DR—or about 6% of DR used to meet total ISO system resource adequacy requirements. Since this capacity is not bid or scheduled into the ISO market, its performance cannot be verified.

Distributed Energy Resources
A recent policy change in California significantly increased the payback period for residential BTM PV. As predicted, installations of residential rooftop solar systems have fallen to near three-year lows over the past year; existing systems were grandfathered in. Now, the California legislature is considering a bill to undo that grandfathering by reducing those existing net metering contracts with IOUs from 20 years to 10. AB 942 would impact the value of solar on the nearly 2 million homes that have installed panels years ago by shifting them to the "net billing tariff" that pays approximately 75% lower rates for energy sent back to the grid. Given California's shifting policy environment, it is difficult to predict future adoption of BTM PV solar.

Generation

- **Aging Thermal Resource Fleet:** During the summer, aging thermal resources can become a concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. In addition, thermal plant and system operators are becoming increasingly hard to replace, as there appears to be difficulty in finding personnel with the necessary experience to fill these rolls. Succession planning is becoming an integral part of successful thermal plant operation.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round. BTM resource generation can be masked from the transmission operator and BA. For example, localized cloud coverage limiting BTM output has been seen to increase demand by 200 MW, requiring unplanned additional resources to be dispatched.

Flexible operating reserves remain on standby to address the uncertainty associated with BTM output.

- **BESS Fires:** BESS fires have occurred in California. These are isolated events that can render a BESS inoperable. Electrical faults, manufacturing defects, degradation due to aging, and gas buildup can all lead to fires. New technologies for passive fire suppression, such as immersion cooling, are being developed to reduce the occurrence of BESS fires.
- **Gas Fleet Derates:** Gas resources in this subregion can be derated during extremely hot weather in the summer due to ambient conditions. Quantifying gas fleet limitations and ensuring there are alternative resources available to meet demand is paramount.
- **Hydro Variability:** Primarily during the summer season, variations in annual precipitation can have a significant impact on water supply. Extended droughts can reduce head pressure, directly resulting in the reduction of hydro capacity. Improvements in hydro models for run off and precipitation are in progress to address these concerns. For resource adequacy models, a 1-in-5 dry-year planning scenario is used.
- **Inertia Decline on System:** Local and federal regulations have driven a reduction in traditional spinning mass generators, which has exacerbated frequency deviations in California. Operating plans are being updated with the necessary steps to mitigate this issue. This issue is observed year round.
- **Solar Variability:** Solar output variability is a concern year round. Spring, fall, and winter often have overcast cloud coverage in California, which can make solar output difficult to forecast. Summer evenings tend to be a time of day when demand is elevated but solar output declines. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.
- **Wind Variability:** Wind variability is an operational concern year round. Toward the end of summer, the beginning of winter, and the beginning of spring, Santa Ana Winds can create overspeed conditions for wind turbines, limiting their output. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.

Electric-Gas Coordination

Most entities in California consider electric-gas coordination in long-term planning studies. Resource Planners collaborate with gas supply teams to gather assumptions on forecasted gas deliveries and pricing. Constraints are not directly incorporated in resource planning studies.

Operating Procedure 4120 ensures that CAISO provides daily estimated gas usage reports to gas transmission operators (GTO). These are used as the basis for gas curtailment event planning. This procedure helps mitigate risks associated with gas supply limitations that may impact generation resources and applies to both real-time and day-ahead operations. In addition, participants of RC West have formed the Real-Time Working Group (RTWG). This group convenes prior to extreme weather events to prepare for potential gas supply interruptions. California entities that are part of RC West also participate in the Northwest Mutual Assistance Agreement (NWMMA). Communication protocols include following NERC Reliability Standard COM-002-4 which contains predefined communication procedures. In addition, plant operators work directly with power supply and gas schedulers to coordinate scheduling and dispatch of gas generating resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

California has a mandate for its electricity supply to be 60% carbon free by 2030 and is currently on track to meet that level. The requirement for 100% carbon free is set at 2045.

Transmission

The ITCS report showed that in a heat wave Northern California may be energy-deficient.

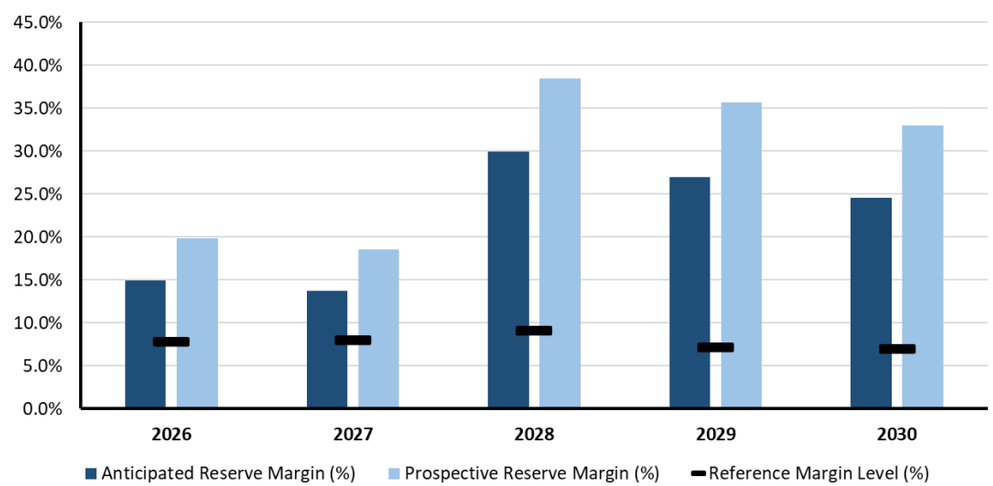


WECC-Mexico

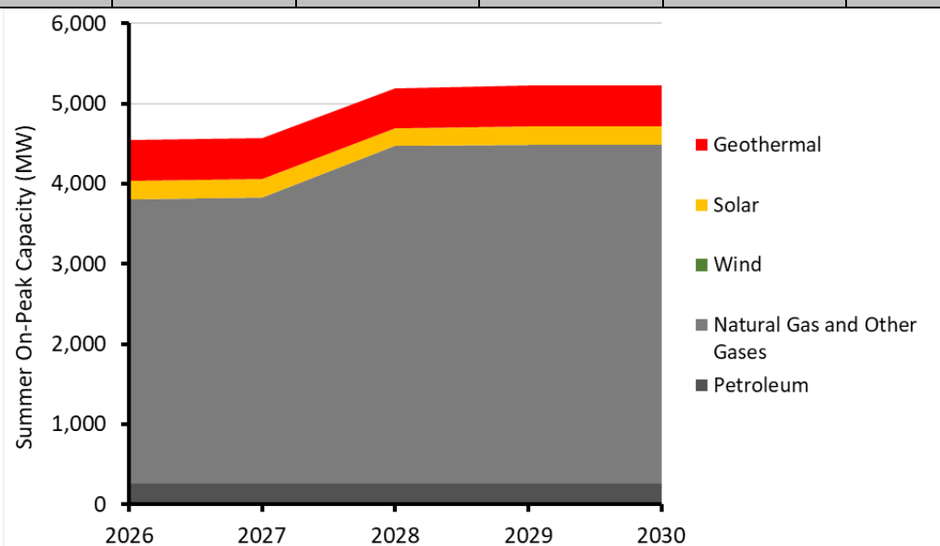
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Additions: Tier 1	717	722	1,396	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Additions: Tier 2	196	198	367	392	392	392	392	367	392	392
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Capacity Transfers (WECC Model)	0	131	410	482	600	600	600	600	600	600
Existing-Certain and Net Transfers	3,825	3,982	4,209	4,307	4,425	4,425	4,425	4,409	4,425	4,425
Anticipated Reserve Margin (%)	14.9%	13.8%	29.9%	27.0%	24.6%	20.0%	15.7%	11.4%	8.0%	4.5%
Prospective Reserve Margin (%)	19.9%	18.6%	38.4%	35.7%	33.0%	28.1%	23.5%	18.4%	15.2%	11.5%
Reference Margin Level (%)	7.8%	8.0%	9.1%	7.2%	7.0%	6.8%	6.7%	7.4%	6.4%	6.3%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Mexico Highlights

- Centro Nacional de Control de Energía (CENACE) is adding three natural-gas-fired combustion turbine generators (totaling 780 MW in summer capacity) by Summer 2026, increasing planned reserves to above RMLs. An additional 740 MW of natural-gas-fired capacity is in development between 2026 and 2027.

WECC-Mexico Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	0	0	0	0	0
Petroleum	259	261	258	259	259
Natural Gas	3,540	3,566	4,212	4,224	4,224
Biomass	0	0	0	0	0
Solar	229	231	214	229	229
Wind	7	5	6	7	7
Geothermal	506	510	505	506	506
Conventional Hydro	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	0	0	0	0	0
Battery	0	0	0	0	0
Total MW	4,542	4,573	5,195	5,225	5,225

WECC-Mexico Assessment

Planning Reserve Margins
The ARM is above the RML until 2035, the last year of the assessment period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the *2025 LTRA*.			

Demand
Average annual demand growth rate for WECC-Mexico is 4.3%. Large-load additions in the forecast are 161 MW through 2035.

Generation
Operational and planning issues related to generation in WECC-Mexico include the following:

- Unplanned Outages of Thermal Sites: High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this assessment area can result in the declaration of an EAA and a request for assistance from RC West. This risk is amplified in the summer when demand is highest.
- Electric-Gas Coordination: Electric-gas coordination is considered in long-term planning studies for the WECC-Mexico area. Current and future gas projects and constraints that could compromise supply to generators are incorporated in planning studies. Constant gas supply monitoring is conducted to ensure generating assets remain reliable throughout the year. Multiple suppliers are also available to generators in WECC-Mexico. This allows for supply redundancy if one supplier is experiencing limitations. Communication between gas suppliers and system operators includes the sharing of gas infrastructure maintenance information and consumption forecasts which are provided on a weekly, monthly, and annual cadence.

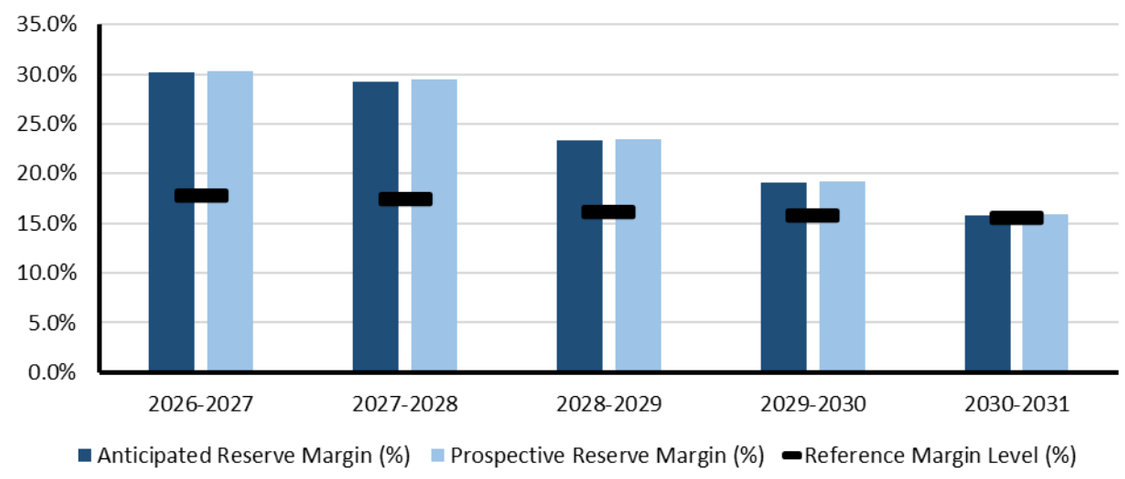


WECC-Northwest

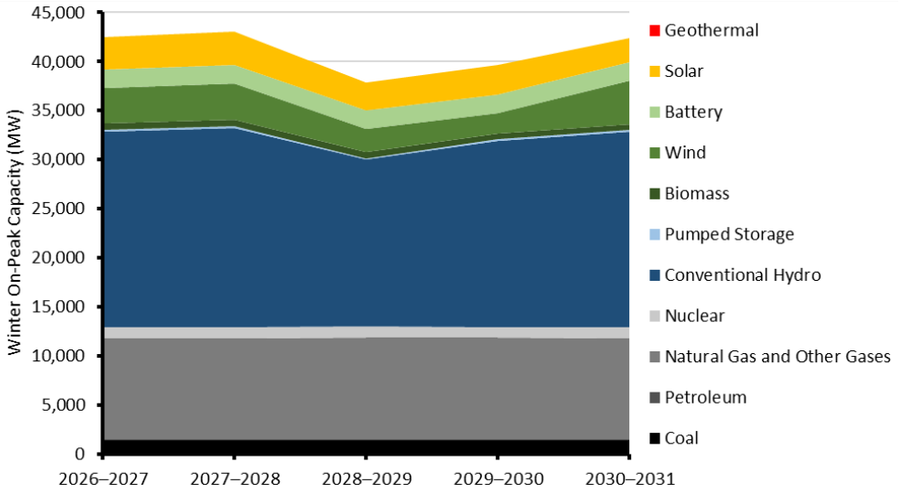
WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	34,426	34,930	36,038	37,017	37,939	38,821	39,455	40,083	40,563	41,064
Demand Response	30	30	30	30	30	30	30	30	30	30
Net Internal Demand	34,396	34,900	36,008	36,987	37,909	38,791	39,425	40,053	40,533	41,034
Additions: Tier 1	3,463	3,463	3,219	3,219	3,219	3,219	3,463	3,232	3,221	3,217
Additions: Tier 2	10	49	56	56	56	56	49	56	56	56
Additions: Tier 3	697	830	939	4,958	5,389	5,605	6,267	5,963	5,921	5,903
Net Capacity Transfers (WECC Model)	7,242	7,630	7,316	7,066	6,896	6,825	6,825	6,825	6,630	5,841
Existing-Certain and Net Transfers	41,332	41,653	41,169	40,828	40,652	40,564	40,724	40,558	40,360	39,573
Anticipated Reserve Margin (%)	30.2%	29.3%	23.3%	19.1%	15.7%	12.9%	12.1%	9.3%	7.5%	4.3%
Prospective Reserve Margin (%)	30.3%	29.4%	23.4%	19.2%	15.9%	13.0%	12.2%	9.5%	7.7%	4.4%
Reference Margin Level (%)	17.8%	17.4%	16.1%	15.8%	15.5%	15.3%	15.9%	15.0%	14.9%	14.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Northwest Highlights

- The ARM falls below the RML starting in Winter 2031–2032. The assessment area would need additional resources to meet resource adequacy criteria. More details on members participating in the WRAP can be found on the WRAP Area Map.
- For 2027 and 2029, the peak hour is projected to occur in January at hour beginning 10:00.
- Resource adequacy risk is not significant in the Northwest for 2027.
- In 2029, the Northwest subregion shows 8,080 MWh of EUE, with approximately 85% of that occurring between hours beginning 14:00–19:00 in August. Though the magnitude of EUE is greatest in the summer months, LOLH occurs at a greater frequency in the winter months, particularly in January.
- The majority of EUE occurs during the summer from hours beginning 17:00–19:00, during which period demand is elevated but solar output is dissipating.

WECC-Northwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,516	1,516	1,475	1,475	1,475
Petroleum	97	97	95	95	95
Natural Gas	10,539	10,533	10,480	10,480	10,480
Biomass	657	617	615	536	536
Solar	1,545	1,544	1,622	1,622	1,622
Wind	2,149	2,149	1,319	1,311	1,311
Geothermal	4	4	4	4	4
Conventional Hydro	17,855	17,835	18,279	18,275	18,270
Pumped Storage	146	146	149	149	149
Nuclear	1,112	1,112	1,108	1,108	1,108
Battery	1,934	1,934	1,927	1,927	1,927
Total MW	37,553	37,486	37,072	36,981	36,976

WECC-Northwest Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Winter 2031–2032. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging.

Non-Peak Hour Risk and Energy Assurance

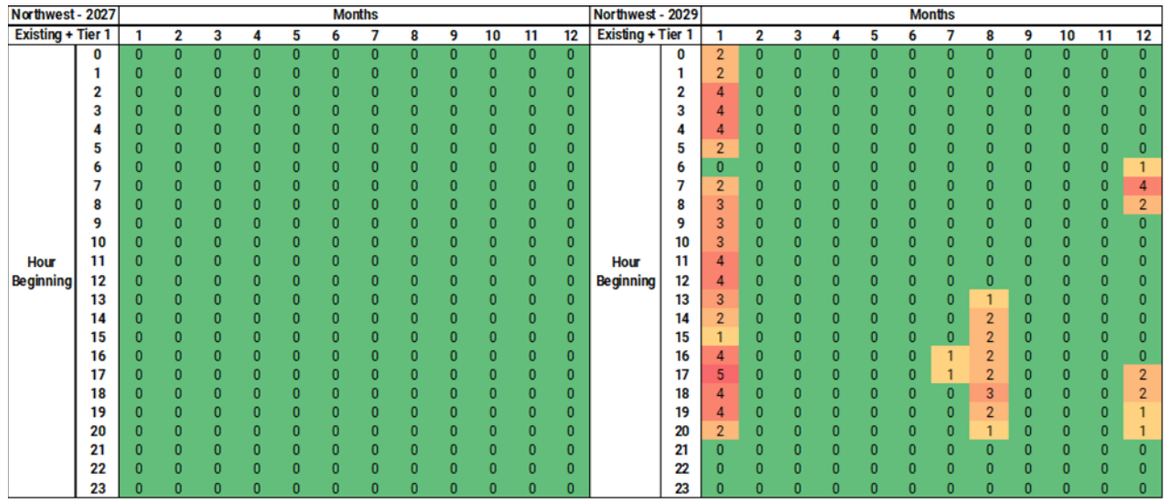
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs over the assessment period, unserved energy and load-loss hours increase in the ProbA results.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0	36.64
LOLH (hours per Year)	N/A	0	85.00
* No prior results as the assessment area is new for the 2025 LTRA.			

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results illustrated in the following heat map figure, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year.



Northwest - 2027	Months												Northwest - 2029	Months										
Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12	Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12
0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0	1	2	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	2	4	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	3	4	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	4	4	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	5	2	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	0	0	1
7	0	0	0	0	0	0	0	0	0	0	0	0	7	2	0	0	0	0	0	0	0	0	0	0	4
8	0	0	0	0	0	0	0	0	0	0	0	0	8	3	0	0	0	0	0	0	0	0	0	0	2
9	0	0	0	0	0	0	0	0	0	0	0	0	9	3	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	10	3	0	0	0	0	0	0	0	0	0	0	0
Hour Beginning 11	0	0	0	0	0	0	0	0	0	0	0	0	Hour Beginning 11	4	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	12	4	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0	13	3	0	0	0	0	0	0	1	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0	14	2	0	0	0	0	0	0	2	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0	15	1	0	0	0	0	0	0	2	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0	16	4	0	0	0	0	0	1	2	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0	17	5	0	0	0	0	0	1	2	0	0	0	2
18	0	0	0	0	0	0	0	0	0	0	0	0	18	4	0	0	0	0	0	0	3	0	0	0	2
19	0	0	0	0	0	0	0	0	0	0	0	0	19	4	0	0	0	0	0	0	2	0	0	0	1
20	0	0	0	0	0	0	0	0	0	0	0	0	20	2	0	0	0	0	0	0	1	0	0	0	1
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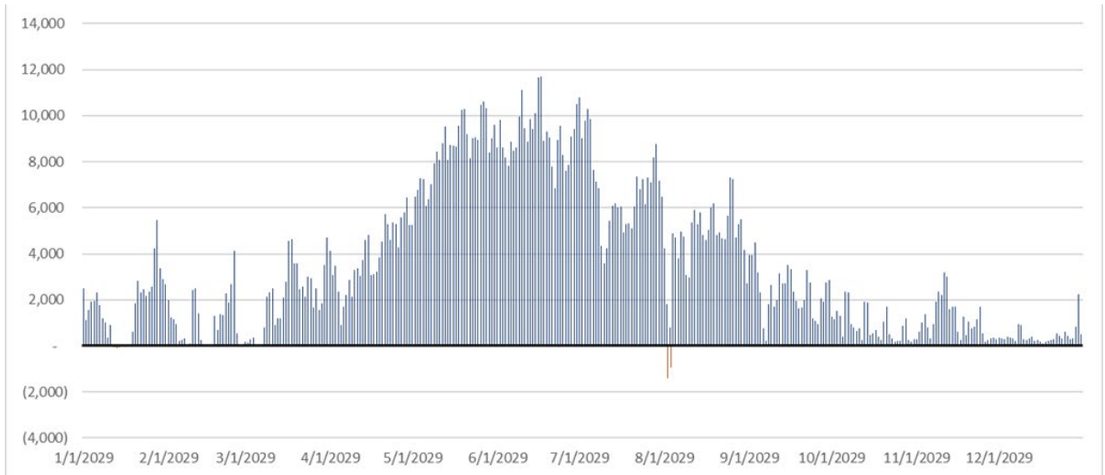
22	0	0	0	0	0	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	23	0	0	0	0	0	0	0	0	0	0	0	0

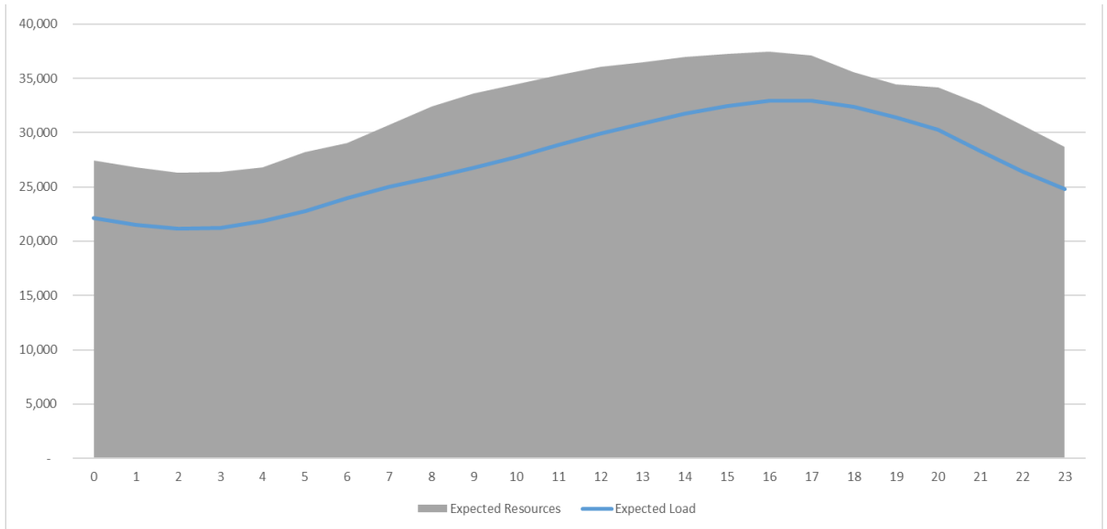
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Northwest Assessment Area in 2027 and 2029

In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Northwest meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Northwest has excess energy that can be transferred to neighboring areas. Winter months are when WECC-Northwest's excess energy is at its lowest, and at times in the 2029 study year internal resources are not sufficient for demand. In summer months, WECC-Northwest is projected to have its highest amount of excess energy, though these supplies can still be insufficient for modeled demand during extreme heat events. Such occurrences can cause deficits represented in the figure below, and energy can go unserved when neighboring areas do not have surplus energy to transfer.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. For the Northwest, this occurs in mid-to-late summer. LOLH occurs from hours beginning 14:00 through 19:00. The majority of EUE during these hours occurs from hours beginning 17:00–19:00, during which period demand remains elevated whereas solar output dissipates. There is no LOLH in 2027. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Northwest assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual demand growth rate for WECC-Northwest is 2.7%. The primary drivers are data centers, residential electrification, residential customer growth, transportation electrification, and semiconductor manufacturing. Large-load additions in the forecast are 7,652 MW through 2035.

Distributed Energy Resources

In the Northwest, Oregon IOUs continue to offer net metering with carryover credits within a calendar year and annual excess credits going to low-income programs. However, the state's largest IOU has proposed a change that largely mirrors California's revised lower credits; if adopted, this would slow the rate of installations in Oregon as well (where the latitude and climate already lengthen the customer's payback period relative to California).

In Washington, utilities have the option to propose a BTM PV credit that is less than the retail rate once they reach a threshold of 4% of their 1996 peak load. The current program is in effect until at least 2029. However, given the progress toward the 4% penetration rate (below), that year may trigger a slowdown in new installations of BTM PV.

Generation

Operational and planning issues related to generation in WECC-Northwest include the following:

- **Aging Thermal Resource Fleet:** A year-round concern for this subregion is an aging thermal resource fleet. Older resources require additional maintenance and can be prone to forced outages or partial derates. Necessary maintenance and capital expenditures are made to ensure these generators provide reasonable performance when called upon. Planned maintenance outages for these resources may be done at a higher frequency during the shoulder months to avoid unplanned outages during the summer months. However, major upgrades to aging infrastructure reduce system capability for extended periods of time, increasing reliance on imports. Supply chain delays and staffing issues can cause planned outages to extend well beyond their anticipated end date. Staffing shortages have been noted by multiple entities in the Northwest.
- **Hydro Variability:** The Northwest has a large share of hydro resources in its portfolio making hydro generating capability a concern year-round. Seasonal hydro variability and below average inflows observed by some entities in this region from April through November of last year resulted in projects being ran at minimum flow. Underperforming hydro resources can result in entities relying heavily on imports to meet peak load hours. During extreme cold conditions, run of river hydro sites can also be derated due to icing. Performing maintenance during shoulder seasons can help keep hydro on-line during the winter and summer seasons. Improving hydro forecasting for short- and long-term planning models can assist system dispatchers with daily operating plans and resource planners in completing accurate resource adequacy studies.
- **Solar Variability:** Solar output variability due to cloud coverage can be a minor concern year-round in this subregion. Entities in this subregion state there are sufficient flexible resources in their portfolio to address solar output uncertainty.
- **Wind Variability:** Wind variability is of particular concern for this subregion during the winter. Cold weather mixed with moisture can cause icing conditions on wind turbine blades, which can severely derate a wind site. Entities in this subregion state that there are sufficient flexible resources in their portfolio to address wind output uncertainty in the winter.
- **Electric-Gas Coordination:** The Northwest subregion contains entities that consider electric-gas coordination in long-term planning studies, as well as entities that do not. Several gas supply options for future generating assets are evaluated to ensure alternatives exist if one supply point is curtailed. Price certainty from suppliers is also a major consideration in planning studies. Annual natural-gas-load studies are conducted to help identify parts of the gas distribution system that may experience low pressure during peak cold conditions. These areas of the gas system are identified, and recommendations to address this issue are prioritized and completed. If an issue cannot be addressed within a short period of time, contingency plans are developed for these areas during high gas demand or peak cold conditions. Entities in the Northwest subregion are participants in the NWMMA mentioned earlier in the Basin subregion. Status reports and planned resource output forecasts are communicated between electric and gas teams daily to ensure operational needs are met.
- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Washington is required to have zero coal generation by 2025, be greenhouse gas neutral by 2030 (can use offsets), and be 100% non-emitting by 2045 without using offsets. Oregon passed a requirement for its investor-owned utilities to be 80% below their 2005 emissions baseline by 2030, 90% below by 2035, and 100% below (zero emissions) by 2040. Montana has a 15% renewables target that has been met, with no incremental increases in the out-years.

Transmission: PacifiCorp's Blueprint transmission project will connect major resource and load areas in central and eastern Oregon through construction of approximately 320 miles of new 500 kV transmission line and associated 500 kV and 230 kV system upgrades, in three primary segments planned to be fully in-service in 2028 and 2032. The Blueprint project will largely parallel the existing Northwest AC Intertie 500 kV system, interconnecting at various points and requiring significant coordination with ac Intertie owners and other affected systems. Affected paths include WECC Paths 14, 66 and 75.

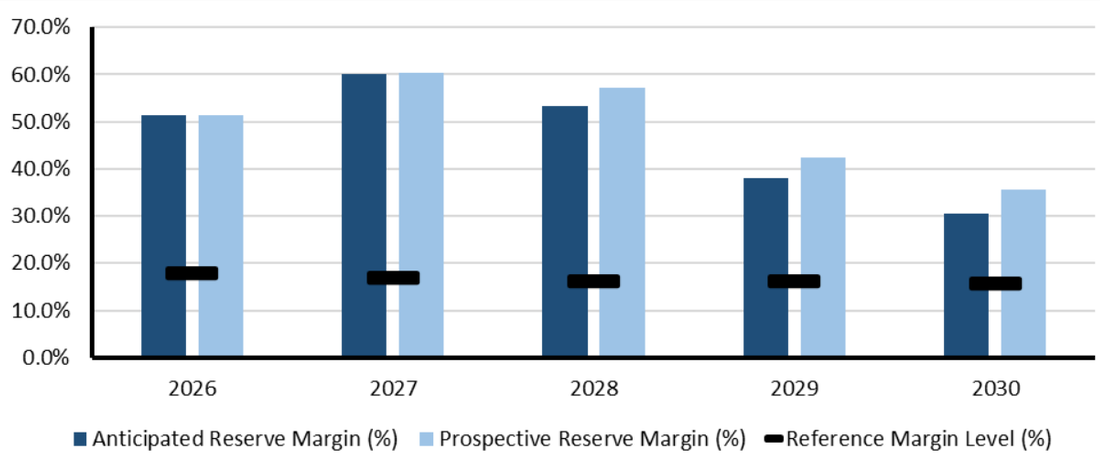


WECC-Rocky Mountain

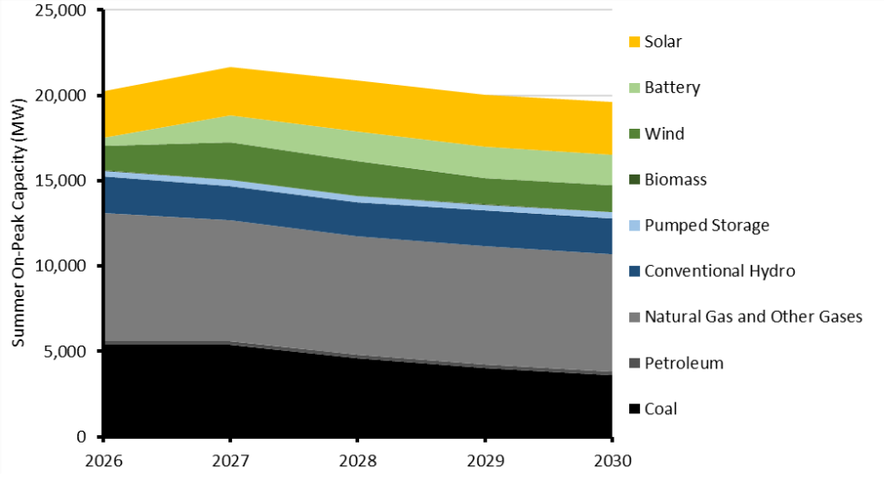
WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,004	14,338	14,565	15,021	15,442	15,873	16,306	16,764	17,207	17,297
Demand Response	287	290	293	285	287	290	293	296	298	301
Net Internal Demand	13,717	14,048	14,272	14,736	15,154	15,583	16,013	16,468	16,909	16,997
Additions: Tier 1	1,771	3,486	3,979	4,079	4,079	4,079	4,355	4,299	4,079	4,079
Additions: Tier 2	0	45	585	640	761	761	810	810	761	761
Additions: Tier 3	17	178	925	1,160	1,373	3,207	3,276	4,188	4,274	4,370
Net Capacity Transfers (WECC Model)	391	661	852	179	50	23	0	0	0	0
Existing-Certain and Net Transfers	18,979	18,995	17,884	16,278	15,696	14,882	14,721	14,329	14,143	14,098
Anticipated Reserve Margin (%)	51.3%	60.0%	53.2%	38.1%	30.5%	21.7%	19.1%	13.1%	7.8%	6.9%
Prospective Reserve Margin (%)	51.3%	60.3%	57.3%	42.5%	35.5%	26.6%	24.2%	18.0%	12.3%	11.4%
Reference Margin Level (%)	17.8%	17.0%	16.2%	16.1%	15.7%	15.2%	13.5%	11.9%	14.1%	13.9%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Rocky Mountain Highlights

- ARM remains above the RML through 2033. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period.

WECC-Rocky Mountain Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	5,383	5,376	4,623	4,034	3,585
Coal*	5,053	5,376	4,429	3,379	2,180
Petroleum	204	204	204	204	204
Natural Gas	7,522	7,083	6,897	6,902	6,902
Biomass	6	6	6	3	3
Solar	2,695	2,873	3,002	3,071	3,071
Wind	1,437	2,218	2,054	1,555	1,550
Conventional Hydro	2,139	2,043	2,029	2,116	2,116
Pumped Storage	346	340	340	346	346
Other	126	126	126	126	126
Battery	496	1,547	1,726	1,817	1,817
Unknown	6	5	5	6	6
Total MW	20,359	21,820	21,011	20,178	19,725
Total MW*	20,029	21,820	20,817	19,523	18,320

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

WECC-Rocky Mountain

Planning Reserve Margins
The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period. In Winter 2033–34, the ARM falls below the RML, but the prospective resources are expected to sufficiently cover a shortfall. No BAs in this region are WRAP participants.

The Public Service Company of Colorado (PSCo), a subsidiary of Xcel Energy, has used a 16.3% long-term PRM requirement in its Electric Resource Plan (2021), based on a loss of load probability of 1-day every 10 years. PSCo's reserve margin is not used in WECC's methodology for the LTRA.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
*No prior results as the assessment area is new for the 2025 LTRA.			

Since WECC-Rocky Mountain does not show any LOLH or EUE in 2027 or 2029, no additional reporting of results or visualizations are provided.

Demand
Average annual demand growth rate for WECC-Rocky Mountain is 2.5%. The primary drivers are data centers, commercial customer growth, and industrial customer growth. Large-load additions in the forecast are 574 MW through 2035.

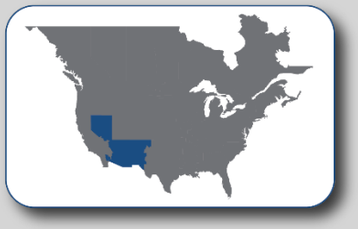
Demand-Side Management
PSCo offers a wide array of DR programs. Total summer demand-reduction estimates for controllable programs for can be found in its Demand Side Management & Beneficial Electrification Plan.

Distributed Energy Resources
BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DERs).

Generation
Operational and planning issues related to generation in WECC-Rocky Mountain include the following:

- **Unplanned Outage Extensions:** Supply chain issues, unplanned discovery work, and vendor availability have driven unplanned extensions of resource outages in the Rocky Mountain area. Difficulty in boiler feed pump procurement has resulted in at least one generating asset being unavailable for over nine months. Another thermal site was undergoing a rotor swap and piping inspection, which revealed significant weld defects and pipe cracks. This resulted in a two-month outage being extended into the following year. A hydro site has been unavailable for much of 2024 due to a penstock leak which has been unable to be repaired due to vendor unavailability. Alternative vendors are being sought after for hydro repair work, and contracts to expedite the procurement of equipment will be in place going forward to mitigate these issues.
- **Solar and Wind Variability:** Smaller entities in the Rocky Mountain area have stated that wind and solar variability is a concern year-round due to a lack of geographic diversity. These entities are pursuing advancement into RTOs to leverage the advantages of a wider footprint and additional resources.
- **Electric-Gas Coordination:** The Rocky Mountain area contains entities that consider electric-gas coordination in long-term planning studies as well as entities that do not. For entities that do consider electric-gas coordination, peak capacity requirements for the local distribution company (LDC) and generating assets are inputs into long term planning models. Peak capacity requirements define the pipeline capacity and contractual volumes needed to fulfill LDC and electric needs. In addition, known and historical constraints on pipelines are considered in resource planning studies. Gas suppliers in this subregion have multiple delivery points to resources. This allows for an alternative location for delivery if one delivery point is inaccessible. In addition, gas supply teams provide an email with natural gas price information and constraints to generation dispatchers and marketers daily. During times of cold weather, this communication stream can be expanded to include interstate gas control and commercial operations.

- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Colorado requires investor-owned utilities to adopt plans to reduce greenhouse gas emissions by at least 80% by 2030, using a 2005 baseline. While the state is on track to achieve this, the additional goal of being 100% carbon free by 2040 is being discussed by utilities, regulators, and legislators, with a proposal to extend the out-year to 2050 in light of the upward pressure on the cost of renewables caused by potential repeal of tax credits and higher tariffs on imports.

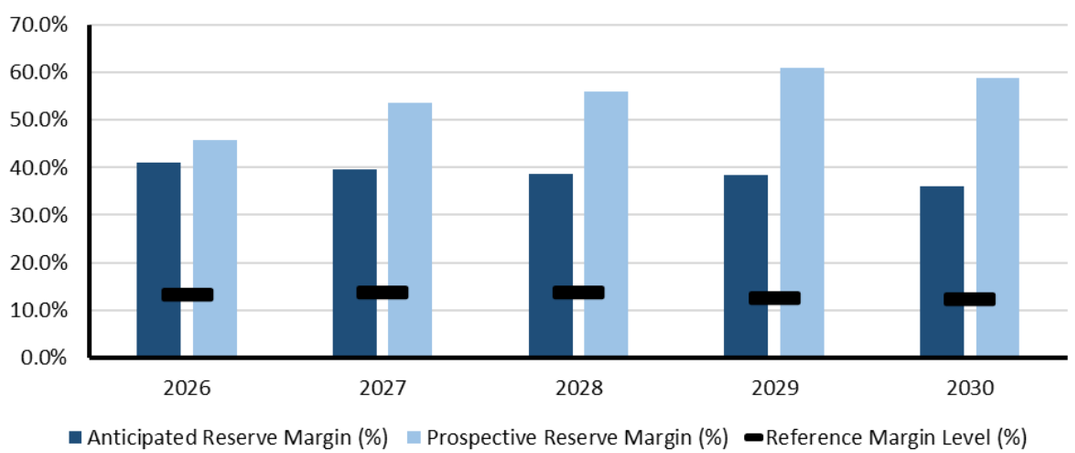


WECC-Southwest

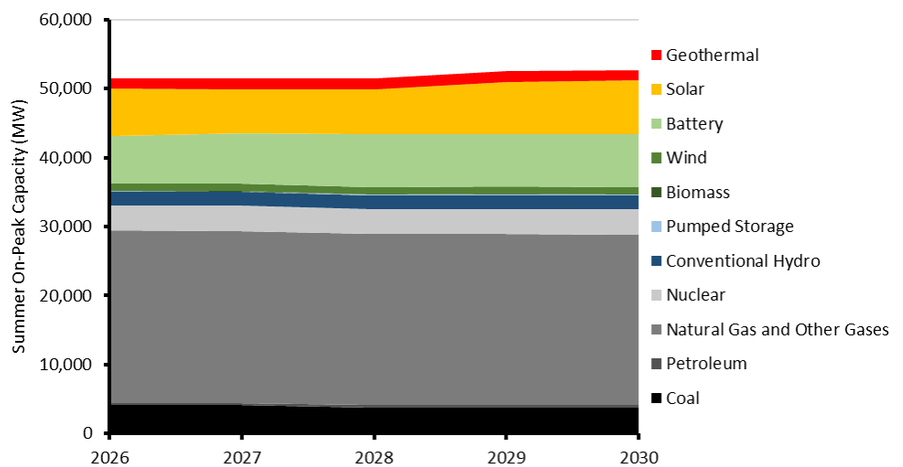
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	37,407	38,911	40,429	41,887	43,551	44,772	45,664	46,317	47,226	47,988
Demand Response	237	258	264	272	282	237	258	264	272	282
Net Internal Demand	37,169	38,653	40,165	41,615	43,269	44,535	45,405	46,053	46,953	47,706
Additions: Tier 1	6,639	7,501	8,155	8,562	8,914	8,914	8,914	8,396	8,852	8,852
Additions: Tier 2	1,771	5,410	6,994	9,369	9,872	11,263	11,286	10,468	11,286	11,252
Additions: Tier 3	2,502	3,899	5,242	7,562	9,710	12,409	14,804	14,801	24,521	24,571
Net Capacity Transfers (WECC Model)	902	2,544	4,162	5,101	6,301	5,895	5,570	4,880	5,030	4,715
Existing-Certain and Net Transfers	45,794	46,457	47,523	49,023	49,986	49,308	47,432	44,294	44,948	43,944
Anticipated Reserve Margin (%)	41.1%	39.6%	38.6%	38.4%	36.1%	30.7%	24.1%	14.4%	14.6%	10.7%
Prospective Reserve Margin (%)	45.8%	53.6%	56.0%	60.9%	58.9%	56.0%	49.0%	37.1%	38.6%	34.3%
Reference Margin Level (%)	13.3%	13.7%	13.6%	12.6%	12.2%	12.0%	11.7%	12.3%	11.3%	11.1%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Southwest Highlights

- ARM remains above the RML through 2034. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM falls below the RML in Summer 2034. With the addition of Prospective Resources, the area can remain above RML.

WECC-Southwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	4,121	4,116	3,749	3,754	3,754
Coal*	3,761	4,116	3,749	3,754	2,576
Petroleum	341	340	340	336	336
Natural Gas	24,978	24,887	24,817	24,837	24,750
Biomass	46	46	46	46	46
Solar	6,867	6,349	6,503	7,474	7,804
Wind	1,059	1,055	1,055	1,059	1,050
Geothermal	1,555	1,555	1,607	1,572	1,454
Conventional Hydro	1,984	1,989	1,989	1,982	1,981
Pumped Storage	113	113	113	113	113
Nuclear	3,641	3,640	3,640	3,641	3,641
Battery	6,824	7,325	7,657	7,671	7,671
Total MW	51,530	51,414	51,516	52,484	52,598
Total MW*	51,170	51,414	51,516	52,484	51,421
***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-Southwest

Planning Reserve Margins
The ARM falls below the RML in Summer 2034 but is covered by the PRM. Arizona Public Service and Public Service Company of New Mexico (PNM) are participants in the WRAP.

Energy Assessment, Including Non-Peak Hour Risk
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

WECC-Southwest does not show any LOLH or EUE in 2027 or 2029; therefore, no additional visualizations are provided.

Demand
The average annual demand growth rate for WECC-Southwest is 3.9%. The primary drivers are data centers, industrial electrification, residential electrification, and residential customer growth. Large-load additions in the forecast are 9,422 MW through 2035.

Demand-Side Management
In the Southwest, Arizona Public Service is in the process of implementing numerous DSM pilots and programs such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. The Residential Energy Storage Pilot enables the company to dispatch a small battery energy storage system up to 20% of the system's capacity.

Salt River Project (SRP) continues to leverage approximately 87 MW of DR capability through more than 75,000 residential smart thermostats, and 41 MW from over 500 businesses enrolled as interruptible customers. SRP intends to achieve 300 MW of dispatchable DR capability by 2035.

PNM programs reduce peak demand by an average of 45 MW per summer event from its two primary programs enrolling the ability to call on commercial customers and residential air conditioners up to 100 hours with a four-hour limit per curtailment.

Distributed Energy Resources
BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DER).

Generation
Operational and planning issues related to generation in WECC-Southwest include the following:

- **Aging Thermal Resource Fleet**: A year-round concern for this subregion is an aging thermal resource fleet. Hundreds of MW of capacity in this region have been operational for over 60 years. During the winter, certain thermal resources are unable to cycle below 40°F due to freezing issues. Older sites also require extensive overhauls such as generator rewinds that can keep resources out of service for extended periods of time and potentially longer than planned as discovery work manifests into additional maintenance. To reduce the risk of age-related forced outages, plant staff adhere to a strict maintenance schedule with frequent inspections, and unit performance is routinely monitored.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round as BTM solar can supply a large amount of energy to the system. Unanticipated loss of BTM generation is addressed through activation of DR programs, peaking power plants, and maintaining sufficient BESS charge. Near-term forecasts for BTM output are also made available to system operators so they can pre-emptively dispatch the system as needed.
- **Coal Inventory Shortages:** In-progress fuel conversions of coal to gas create a balancing act of maintaining coal on-site to operate resources while also avoiding excess coal post conversion. This can limit coal resources to minimum output prior to the fuel conversion outage. In addition, site-specific challenges at coal mines have delayed coal deliveries to resources in this subregion. Active management of on-site inventory and procurement of fuel from other sources can mitigate these issues.

- **Gas Fleet Derates:** Gas resources in this subregion can be derated during hot weather in the summer due to ambient conditions. During the winter, gas supply has been cut to plants in this subregion during cold snaps. Near-term monitoring of gas availability along with additional market purchases or fuel switching for capable resources can assist in mitigating supply issues.
- **Solar Variability:** Solar output variability is a concern year-round for this subregion. It is a primary concern on summer evenings as solar output rapidly declines whereas load increases or remains elevated. Activation of DR programs, peaking/flexible power plants, and maintaining sufficient BESS charge are all potential strategies to mitigate this issue. Large changes in solar output can also cause extreme ACE fluctuations, which are addressed using BESS.
- **Electric-Gas Coordination:** Most entities in the area consider electric-gas coordination in long-term planning studies. Resource planning models compare forecasted gas usage on both daily and hourly intervals to firm contractual rights. Gas usage exceeding firm obligations results in unserved energy, which can then be addressed via spot market purchases, short-term gas transport capacity purchases, or the dispatching of other resources. Entities also account for forecasted LDC usage and reduce the available natural gas for electric use by this amount. Resource adequacy models do not yet incorporate gas pipeline constraints, but consideration is being given to how to incorporate these into modeling efforts.

  Procedures to mitigate gas supply issues include anticipating losses of scheduled gas from the supply side, ensuring scheduled pipeline maintenance is accounted for in operations, and maximizing the availability of dual fuel resources. Planning teams also coordinate with operations teams for gas supply issues on a season-ahead basis, and operations can re-dispatch the system as needed to manage fuel shortages. During times of potential freeze-offs, trading practices may also be changed to not overextended firm load requirements. Entities maintain winter and summer readiness plans that are shared between electric system operators and gas pipeline operators to ensure maintenance schedules are aligned. Gas system limitations are made known to electric system operators through routine meetings between system operators and pipeline operators.
- **Renewable Portfolio, Clean Electricity & Emissions Standards:** In the Southwest region, Arizona has an RPS mandate for its electric supply to be 15% renewable by 2025. Separately, APS has committed to ending the use of coal-fired generation after 2031, and the company set a 100% carbon free by 2050 goal. SRP has goals to reduce CO2 emissions per MWh by 62% from 2005 levels by 2035 and 90% by 2050; TEP will stop using coal by 2032 and plans to reduce carbon emissions by 80% by 2035. New Mexico has set more aggressive mandates, requiring 50% renewable by 2030, 80% by 2040, and 100% by 2045.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[49] for the summer and winter of each year.[50] Projected total internal demand is based on normal weather (50/50 distribution)[51] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[52]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-Alberta	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-Basin	Summer	Noncoincident	
WECC-British Columbia	Winter	Noncoincident	
WECC-California	Summer	Noncoincident	
WECC-Mexico	Summer	Noncoincident	

[49] Glossary of Terms Used in NERC Reliability Standards.
[50] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).
[51] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.
[52] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[52]**	**Load Forecasting Entity**
WECC-Northwest	Winter	Noncoincident	
WECC-Rocky Mountain	Summer	Noncoincident	
WECC-SW	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources[53]

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[54]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[55]

[53] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[54] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[55] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[56]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[57]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[56] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[57] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[58]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[59] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[60] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[61] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[62]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.

[58] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[59] BES Definition
[60] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[61] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[62] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

- **Adequate:** The ARM is greater than RML.
- **Marginal:** The ARM is lower than the RML and the PRM is higher than RML.
- **Inadequate:** The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[63] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

- **Normal Risk:** Negligible amounts of LOLH and EUE.
- **Periods of Risk:** LOLH < 2 Hours and EUE < 0.002% of total annual net energy.
- **Significant Risk:** LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.
Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
  - Planned (any of the following):
  - Permits have been approved to proceed

[63] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

- Design is complete
- Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”
  - Other projected lines that do not meet requirements of “Under Construction” or “Planned”

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2026–2030)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2025-2026 Summer: 8.1% Fall: 14.9% Winter: 19.1% Spring (2027): 26.2%	Planning Reserve Margin	Yes: Established Annually[64]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[65]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	13.0–13.4%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[66]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	15.8–22.6%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	11.9–12.2%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	18.6–26.3%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[67]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[64] In MISO, the states can override the MISO PRM.

[65] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[66] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

[67] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Reference Margin Levels for Each Assessment Area (2026–2030)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[68]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[69]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[70]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustent for non-modeled market considerations	ERCOT Board of Directors
WECC-Alberta	11.6–17.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[71]
WECC-Basin	12.3–14.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-British Columbia	11.6–12.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-California[72]	19.2–20.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Mexico	7.0–9.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Northwest	15.5–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Rocky Mountain	15.7–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Southwest	12.2–13.7%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]

[68] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[69] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[70] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[71] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[72] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.

2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[73] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[74] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[75] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[76,77]

3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[78] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[79]

[73] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[74] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[75] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[76] NERC IBR Activities
[77] Order No. 901 Work Plan
[78] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[79] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[80]

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	Cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and BAs for use in operating plans. Additional Reliability Standard requirements were developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity Staff Report—The February 2021 Cold Weather Outages in Texas and the South Central United States* and respond to FERC directives.[81] In September 2025, FERC approved EOP-012-3 with an effective date of October 1, 2025. The revised standard strengthens generator preparedness by providing clearer and more effective requirements. In the approval order, FERC also directed NERC to make information fillings to FERC every two years beginning in October 2026 and continuing through October 2034, to assess the adequacy of the standard's ability to address reliability concerns and inform potential future modifications.	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[82] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[80] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[81] Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* and *Project 2024-03 Revisions to EOP-012-2* on NERC's standards development page. Project 2021-07

[82] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered BPS-connected IBRs.[83] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[84]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 1. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	**Description**	**Product/Reliability Solution**
***Interregional Transfer Capability Study* (ITCS)**	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024[85]. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis was published in 2025.[86] See **Interregional Transfer Capability Study (ITCS) Canadian Analysis**.	ERO Study and Recommendations

[83] FERC Order Issued November 17, 2022
[84] RSTC Approved Documents
[85] NERC's *Interregional Transfer Capability Study* (ITCS) Final Report
[86] NERC's *Interregional Transfer Capability Study (ITCS) Canadian Analysis* Final Report

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.
2. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.
3. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [87]
4. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.
5. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[88]

[87] NERC ERS Measure 6 Forward Tech Brief
[88] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2025 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[89] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[90] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[91]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The statuses of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[92]	Reliability Standards Reliability Guidelines Educational Webinars
Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[89] ERAWG
[90] Project 2022-03
[91] Project 2023-07
[92] DER Activities

Errata

February 2026

- Resource mix changes: Corrected natural gas, solar, wind, conventional hydro, battery, and total resource capacity for 2025 in Table 16. Corrected the caption of Figure 16 (p. 30).
- WECC British Columbia: Corrected highlights for BC Hydro's most recent 10-year capital plan (p. 144 and 146), corrected the WRAP participation description (p. 145), corrected the DER programs (p. 145), and included a more current drought outlook from October 2025 in the Generation section (p.145)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-179
SPP Deficiency Response

Attachment 1

SPP's Response to the October 3 Letter

Question 1

1. In your transmittal, you state that SPP does not propose any Tariff revisions for its generator interconnection procedures or transmission service study processes in these filings. You state that, upon integration and execution of the Membership Agreements by Expansion Members, Expansion Members' existing planning processes will be integrated into SPP's existing Tariff processes, which will continue to be consistent for all RTO members. You state that there are nevertheless certain transition plans that will be finalized between SPP and Expansion Members prior to the planned effective date.[1]

   a. Regarding transmission service requests, you explain that SPP and Expansion Members are developing a plan to transition transmission service requests that are granted by Expansion Members prior to the effective date into SPP's Open Access Same-Time Information System. For those transmission service requests still being processed on the effective date, you state that SPP is working with Expansion Members on a plan to consolidate Expansion Members' transmission service request queues into SPP's transmission service request queue.[2]

      i. Please identify any existing Tariff provisions that will apply to facilitate the transition of Expansion Members' transmission service request queues into SPP's existing transmission service study processes.

      ii. If no existing Tariff provisions apply, please explain how SPP plans to transition Expansion Members' transmission service request queues into SPP's existing transmission service study processes, including a general timeline for the proposed transition.

   b. Regarding generator interconnection procedures, you state that SPP is working to consolidate Expansion Members' current generator interconnection requests into the SPP generator interconnection study process, beginning on the effective date. You note that application of SPP's generator interconnection procedures to Expansion Members' interconnection requests will depend on the process stage that Expansion Members' interconnection requests are in as of the effective date. Further, you state that SPP expects to clear its current interconnection queue backlog in advance of the planned effective date but that, if it is unable to do so, it

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1 Submission of Revisions to Tariff, Bylaws, and Membership Agreement to Expand the Regional Transmission Organization into the Western Interconnection of Southwest Power Pool, Inc., Transmittal Letter at 21, Docket No. ER24-2184-000 (June 4, 2023) ("Transmittal Letter").

2 *Id.*

may make a future filing with the Commission requesting to process interconnection requests separately in the Eastern Interconnection and the Western Interconnection until SPP is able to clear the current backlog.[3]

i. Please identify any existing Tariff provisions that SPP will apply to facilitate the transition of Expansion Members' generator interconnection queues into SPP's existing generator interconnection study processes.

ii. If no existing Tariff provisions apply, please explain how SPP plans to transition Expansion Members' generator interconnection queues into SPP's existing generator interconnection study processes, including a general timeline for the proposed transition.

Question 1 Response:

1.a(i):

Similar to other expansions of the SPP RTO,[4] there are no existing Tariff provisions that outline the transition of Expansion Members' transmission service request queues into SPP's existing transmission service study processes. Although no Tariff provisions exist, SPP will be following a similar transition facilitation process as it has in previous expansion efforts of the SPP RTO to ensure that transmission service is integrated into SPP's existing transmission service study process.[5]

1.a(ii):

SPP studies requests for Long-Term Service (transmission service with a duration of one-year or longer) through its Aggregate Transmission Service Study ("ATSS") process.[6] Under the ATSS

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3 *Id.* at 21-23.

4 *Sw. Power Pool, Inc.*, 149 FERC ¶ 61,113 (2014) ("Integrated Systems Order"). Southwest Power Pool, Inc., 125 FERC ¶ 61,239 (2008) (Order approving the expansion of SPP to include the Nebraska entities).

5 *Sw. Power Pool, Inc.*, Letter Order, ER14-2850-009 (November 3, 2016). This letter order accepted SPP's compliance filing required by the Integrated Systems Order. In the compliance filing, SPP explained the transition process of integrating the Integrated System members' GI Queues and transmission service request queues into SPP's processes.

6 The details of the ATSS process can be found in Sections 19.4, 32.4 and Attachment Z1 of the Tariff. Additional information on the ATSS process is posted on the Transmission Service Studies page of the SPP website at: https://opsportal.spp.org/Studies/Trans.

process, SPP has open seasons for the submittal of Long-Term Service requests.[7] Upon the close of an open season, all transmission service requests entered during the open season are combined into a single ATSS group and an Aggregate Facilities Study is performed to determine the transmission system upgrades that may be needed to accommodate the requests in that group.[8]

Any entity requesting Long-Term Service across the Expansion Members' facilities that will be processed on or after proposed effective date of April 1, 2026 ("Effective Date") should enter the necessary transmission service requests[9] into the ATSS process during the first scheduled open season of the ATSS. The first open window for the ATSS opens on December 1st and closes on May 31st. The second open window for the ATSS opens on June 1st and closes on November 30th. Any transmission service request entered into the ATSS process will be completed in accordance with the procedures prescribed in the Tariff.[10]

The process and requirements for obtaining Short-Term Service (transmission service with a duration shorter than one-year) are outlined in Attachment C of the Tariff. For an entity that has Short-Term Service reservations that are queued on an Expansion Member's Open Access Same-Time Information System ("OASIS") submitted with a start time prior to the Effective Date and a stop time after the Effective date will concurrently, with its transmission service reservation on the Expansion Member's OASIS, submit a transmission service reservation on SPP's OASIS starting on the Effective Date. The purpose for the concurrent transmission service reservation submittal to both the Expansion Member's OASIS and the SPP's OASIS is to prevent the inclusion of these transmission service reservations in SPP Settlement's monthly transmission service invoicing for any duration of the transmission service reservation before April 1, 2026.

Any existing or additionally granted Long-Term and Short-Term Service on the Expansion Members' transmission system ending after the Effective Date will be transitioned to equivalent transmission service on the SPP System by following the process described in Section 29.2 and Attachment C of the Tariff.[11] Expansion Members are required to submit a new application with SPP for these transitioned transmission services. There will be no ATSS or Short-Term Service study necessary if there are no material changes in the transmission service arrangements. Material changes in transmission service include, but are not limited to, designation or un-designation of

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7 Tariff at Attachment Z1, Section II.

8 *Id.* at Section III.

9 In order to submit a transmission service request on the SPP OASIS, an entity must first complete the customer registration process. More information on the customer registration process can be found on the SPP website at: https://www.spp.org/stakeholder-center/join-spp/.

10 Tariff at Attachment Z1, Section III.

11 Tariff at Part III, Section 29.2 and Attachment C.

Network Resources or Network Loads, changes to MW amounts, POR/POD, Source/Sink, Customer Name, and re-directions.

1.b(i):

Similar to other expansions of the SPP RTO, [12] there are no existing Tariff provisions that outline the transition of Expansion Members' generator interconnection queues into SPP's existing generator interconnection study processes. Although no Tariff provisions exist, SPP will be following a similar transition facilitation process as it has in previous expansion efforts of the SPP RTO.[13]

1.b(ii):

Beginning on the proposed Effective Date, all new interconnection requests seeking to interconnect to the SPP Transmission System, which will include the transmission systems of the Expansion Members, will be submitted in the SPP generator interconnection queue consistent with the requirements in Attachment V of the Tariff.[14] All interconnection requests with a system impact study agreement executed by an Expansion Member as of the close of business on the day prior to the Effective Date and where the final system impact study report has not been completed, may be studied under the terms of the executed study agreement with the Expansion Member or the interconnection customer may terminate the study agreement and transition the request to SPP's generator interconnection queue. Should the interconnection customer elect to remain in the Expansion Member's study queue, following completion of the system impact study and upon issuance of the final interconnection facilities study ("IFS") report by an Expansion Member, SPP will tender a Generator Interconnection Agreement ("GIA") to the Interconnection Customer in accordance with Section 11 of the Generator Interconnection Procedures ("GIP"). Interconnection Customers that elect to terminate the system impact study agreement with the Expansion Member and enter SPP's generator interconnection queue will enter the next open Definitive Interconnection System Impact Study ("DISIS") Queue Cluster Window, if one is not currently open as of the Effective Date.

Interconnection Customers with executed Expansion Member's IFS agreements where the final IFS report is not complete as of the close of business on the Effective Date will have their IFS completed by the Expansion Member in accordance with the terms of their IFS agreement, and upon completion of the IFS will receive an SPP GIA for execution in accordance with Section 11 of the GIP. Similarly, all Interconnection Requests where the Interconnection Customer has received a final IFS report from an Expansion Member but does not have an executed GIA as of

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12 *Supra* at n.4.

13 *Supra* at n.5.

14 Tariff at Attachment V, Section 3.

the Effective Date, will receive an SPP GIA for execution in accordance with Section 11 of the GIP.

In the event SPP has not cleared its existing generator interconnection backlog as of the Effective Date,[15] SPP has committed to making a filing with the Commission to establish a separate interconnection queue for interconnection requests seeking to interconnect to an Expansion Members' transmission system.[16] This filing will ensure that these interconnection requests are not queued for study after those requests that are backlogged and pending study in SPP's generator interconnection queue.

Question 2

2. In your transmittal, you state that SPP proposes to add provisions to sections 4.2.2(b)(vi) and (vii) of the Membership Agreement that will allow any SPP Member that has transmission facilities in either of two of the five new, proposed transmission pricing zones in the Western Interconnection—specifically, the Colorado River Storage Project Zone (CRSP Zone) and the Loveland Area Projects Zone (LAP Zone)—to terminate the Membership Agreement with less than the required 24 months' notice if: (1) WAPA-CRSP, WAPA-RMR, Basin Electric, or Tri-State withdraws from SPP in accordance with their respective withdrawal rights; or (2) the Commission finds that SPP has not adhered to all of the WAPA-CRSP and WAPA-RMR Federal Power Marketing Agency Amendments or the Basin Electric Amendments.[17] SPP's proposed Membership Agreement Amendments set forth the respective withdrawal rights for WAPA-CRSP, WAPA-RMR, and Basin Electric, but not Tri-State.

    a. Please explain why SPP proposes to allow any SPP member with facilities in the CRSP Zone or LAP Zone to withdraw with less than 24 months' advance notice if WAPA-CRSP, WAPA-RMR, Basin Electric, or Tri-State withdraw from SPP.

    b. Please provide further explanation of Tri-State's respective withdrawal rights and how those rights relate to the CRSP Zone and LAP Zone.

    c. Please explain why the proposed withdrawal rights in sections 4.2.2(b)(vi) and (vii) of the Membership Agreement are limited to SPP members with transmission facilities in the CRSP Zone or LAP Zone.

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15 Pursuant to Attachment V, Section 5, the Backlog Mitigation Period concludes following Decision Point for the DISIS-2023-001 cluster.

16 *See* June 2024 Filing at 23.

17 *Id.* at 26-27, 185-187; SPP, Proposed Membership Agreement § 4.2.2(b)(vi)-(vii); *see also id.* § 1 (defining Federal Power Marketing Agency Amendments and Basin Electric Amendments).

Question 2 Response:

2.a:

When Western Area Power Administration, Upper Great Plain Region ("WAPA-UGP"), Basin Electric Power Cooperatives ("Basin Electric"), and Heartland Consumers Power District ("Heartland") (collectively "Integrated System") joined SPP, SPP requested revisions to the SPP Membership Agreement to allow any Member with transmission facilities located in the Upper Missouri Zone ("UMZ") to withdraw from SPP with less than the required twenty-four (24) month notice in the event that WAPA-UGP or Basin Electric withdraws from SPP in accordance with its respective withdrawal rights.[18] The Commission approved these proposed revisions based on SPP's explanation that the withdrawal provisions are necessary due to the integrated nature of the facilities owned by Basin Electric, Heartland, and WAPA-UGP.[19] The Commission also pointed out in the Integrated Systems Order that the withdrawal obligations for the Integrated System are similar to provisions the Commission accepted to facilitate the integration of the entities in Nebraska (Lincoln Electric Systems, Omaha Public Power District, and Nebraska Public Power District) in Docket No. ER08-1601.000. Overall, the UMZ, as a multi-owner pricing Zone that was highly integrated, was only a viable Zone if they maintained critical mass of those Transmission Owners.

Similar to the Integrated System, the transmission facilities of Transmission Owners in the CRSP Zone and the LAP Zone are highly integrated. If Western Area Power Administration-Colorado River Storage Project Management Center ("WAPA-CRSP"), Western Area Power Administration-Rock Mountain Region ("WAPA-RMR"), Basin Electric, or Tri-State were to terminate membership in SPP, it would be necessary for all Transmission Owners in CRSP Zone and the LAP Zone to also terminate membership or effectuate a Partial Termination in that zone. Requiring Transmission Owners in the CRSP Zone and the LAP Zone to provide at least twenty-four months' notice would result in those entities being unreasonably and unduly harmed by being forced to wait to withdraw from SPP even though their transmission facilities are part of highly integrated system that will no longer be under SPP's functional control. Similar to when the Integrated System joined SPP, the CRSP Zone or LAP Zone will become non-viable pricing zones if WAPA-CRSP, WAPA-RMR, Basin Electric, or Tri-State were to terminate membership in SPP,

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[18] Revisions to Tariff, Bylaws, and Membership Agreement of Southwest Power Pool, Inc., Docket ER14-2850 (Sept. 11, 2014).

[19] *Sw. Power Pool, Inc*., 149 FERC ¶ 61,113, at P 134, P 136 (2014) ("Integrated System Order").

and the transmission facilities within those zones will need to be transitioned out of the SPP if the loss of critical mass results in the elimination of either or both of those zones from the RTO.

It should be noted that although SPP is requesting in this filing an exemption from the twenty-four month (24) withdrawal notice provisions under the Membership Agreement, any Member who exercises its withdrawal rights under the Membership Agreement will still be responsible for other withdrawal obligations outlined in the Membership Agreement and Bylaws.

2.b:

SPP did not request in its original filing to include any unique amendments to the Membership Agreement on Tri-State's behalf, unlike the unique amendments for current federal members or federal Expansion Members. Outside the withdrawal notice provisions referenced above in response to 2.a, Tri-State's respective withdrawal rights are outlined in the standard provisions in the Membership Agreement and Bylaws.

Tri-State's transmission system located in the CRSP Zone and the LAP Zone, as stated above in response to 2.a, is highly integrated into the transmission systems of other Transmission Owners in those Zones. These integrated transmission systems in the CRSP Zone and the LAP Zone necessitate similar notice provisions for Tri-State if WAPA-CRSP, WAPA-RMR, or Basin Electric were to provide less than twenty-four months' notice of withdrawal from SPP.

2.c:

The withdrawal notice provisions are only applicable to Transmission Owners in the CRSP Zone and the LAP Zone, because these are the only Zones that will be in the SPP West Region when the Commission approves the Proposed Tariff revisions that have numerous Transmission Owners with highly integrated transmission systems. This is similar to the notice provisions applied to the Transmission Owners located in the UMZ (as approved in the Integrated Systems Order). The UMZ is the only Zone in SPP that currently has these similar proposed withdrawal rights.

Question 3

3. In your transmittal, you state that SPP proposes to extend the Federal Service Exemption[20] to include WAPA-CRSP Replacement Energy, as necessitated by the Grand Canyon

[20] As part of WAPA-UGP's integration into SPP as a transmission-owning member in 2015, the Commission accepted revisions to the Tariff to implement a Federal Service Exemption, which exempts transactions for the transmission of federal power to serve WAPA-UGP's statutory preference customers from congestion and marginal loss charges. *See Sw. Power Pool, Inc.*, 149 FERC ¶ 61,113, at PP 48-53 (2014); *see also* Proposed Tariff atPart I, Section 1 (F-Definitions).

Protection Act of 1992.[21] The Proposed Tariff provides that WAPA-CRSP Replacement Energy is "necessitated by WAPA-CRSP's inability to deliver sufficient energy from reservoir projects under the control of the U.S. Bureau of Reclamation in the marketing area of WAPA-CRSP for reasons such as persistent drought or environmental constraints."[22] You explain that the purpose of FSE-Qualified WAPA-CRSP Replacement Energy is to provide energy, as needed, for WAPA-CRSP to meet its Statutory Load Obligations,[23] after using WAPA-CRSP's available hydroelectric generation.[24]

a. Please explain whether WAPA-CRSP Replacement Energy includes energy acquired to fulfill WAPA-CRSP's Statutory Load Obligations due to WAPA-CRSP's inability to deliver sufficient energy from: (1) *any* reservoir project under the U.S. Bureau of Reclamation's control in the WAPA-CRSP marketing area; or (2) only WAPA-CRSP's Glen Canyon Plant.

b. If the former, please explain in further detail why applying the Federal Service Exemption to WAPA-CRSP Replacement Energy is necessitated by the Grand Canyon Protection Act of 1992.

Question 3 Response:

3.a:

The WAPA-CRSP Replacement Energy provisions requested by SPP in the Proposed Tariff revisions are necessary based on the Energy Policy Act of 2005 and WAPA-CRSP's response to the Grand Canyon Protection Act of 1992To aid the Commission in response to this question, SPP requested that WAPA-CRSP provide additional clarification of their federal statutory requirements and obligations under the Grand Canyon Protection Act of 1992 and the Energy Policy Act of 2005. Attached to these responses as Exhibit No. SPP-0001 to Attachment A is a letter from WAPA-CRSP outlining their statutory obligations under the Grand Canyon Protection Act of 1992 and the Energy Policy Act of 2005.

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21 Reclamation Projects Authorization and Adjustment Act of 1992, Pub. L. No. 102-575, 106 Stat. 4600, §§ 1801–09 (1992).

22 Proposed Tariff at Part 1, Section 1 (W-Definitions).

23 *Id.* (defining Statutory Load Obligations as a "WAPA-Division's power marketing function obligations under Federal law to deliver power and energy to loads which include project use loads, preference power customer loads located in that WAPA-Division's marketing area defined pursuant to its power marketing plan, and other loads required to be served under Federal law. For WAPA-CRSP, Statutory Load Obligations also includes WAPA-CRSP's contractual obligations pursuant to its power marketing plan.").

24 Transmittal Letter at 29.

As described in the letter from WAPA-CRSP, WAPA-CRSP Replacement Energy provisions are not limited to only WAPA-CRSP's Glen Canyon Plant's inability to deliver sufficient energy. WAPA-CRSP Replacement Energy provisions are applicable to any reservoir project under the U.S. Bureau of Reclamation's control in the WAPA-CRSP marketing area.

3.b:

See Exhibit No. SPP-0001 to Attachment A.

Question 4

4. In your transmittal, you state that the proposed expansion into the Western Interconnection will create new metered boundaries and a need to establish a second BAA, which will be incorporated into SPP's Integrated Marketplace. You explain that, under the revised Tariff, the three components of locational marginal price (LMP) in the Integrated Marketplace will be calculated on a BAA basis and, to effectuate those calculations, a separate reference bus will be needed for each BAA. You explain that, although a new reference bus will be established in the SPP West BAA, LMPs will continue to represent the marginal cost of serving demand at the price node while meeting the operating reserve requirements.

   Please provide more information regarding how two separate reference busses, one for each BAA, will accurately model the marginal cost of serving load in each BAA, including the cost of congestion.

Question 4 Response:

A reference bus is a construct used in power flow analysis of a *single interconnected AC network* to describe how power flows through the electrical transmission equipment in a defined electrically interconnected AC network. Today, the SPP Integrated Marketplace utilizes a single reference bus, which is possible because the SPP market exists in a single AC interconnection, the Eastern Interconnection. With the proposed RTO expansion, there will be two electrically asynchronous Balancing Authority Areas ("BAA" or "BAAs") connected by the dispatchable West DC Ties.[25] To accurately model the marginal cost of serving load, including the cost of congestion, in each BAA, SPP must use a separate reference bus in each BAA.

While the Eastern and Western networks are not synchronously connected, SPP will determine a single optimized solution to effectuate one integrated market across the Eastern and Western networks. The market optimization simultaneously determines flows across the West DC Ties and the dispatch and prices in both networks. Each West DC Tie is modeled as a linked withdrawal/injection pair, joining the two BAAs together at the location of that West DC Tie. The modeling of the West DC Ties' capability to transfer Energy between the BAAs will connect the power balance and prices between the two BAAs within the single market optimization. The

[25] *See* SPP, Inc., DC Tie Proposal RTO West at 5 (July 12, 2022), https://spp.org/documents/68648/rto%20west%20dc%20tie%20proposal%20final.pdf.

withdrawal will be modeled within the sending BAA and will represent the amount of Energy being transferred across the West DC Tie. The injection will be modeled within the receiving BAA and will be equal to the sending withdrawal minus losses across the West DC Tie. This modeling allows the market optimization to determine the most economical way to meet obligations across both BAAs. In this way, the market optimization will accurately model the marginal cost of serving load, including the cost of congestion, in each BAA.

SPP will calculate the locational marginal prices ("LMP" or "LMPs") for both BAAs as it does today in the Integrated Marketplace for the Eastern Interconnection. The LMP is the cost to serve the next incremental MW of Energy at each node. Imbedded in this LMP is the marginal cost of Energy, the marginal cost of losses, and the marginal cost of congestion. Utilizing a reference bus for each network allows the marginal cost of losses and the marginal cost of congestion to only represent the losses and congestion for that synchronous network. The marginal cost of Energy is the computed LMP at the reference bus.[26] The LMP at the reference bus will reflect each BAA's economic value of balancing power for that network.

The ability to move energy between the Eastern and Western networks using the West DC Ties impacts the marginal cost to serve load in each interconnection. When there is available capacity of flow on any of the West DC Ties, the marginal cost to serve load in each BAA will be influenced by the cost of the marginal Resource(s) and losses on the West DC Ties. For example, if the marginal Resource(s) is located in the Western network, the Resource may contribute to the marginal cost of serving load in both the Western network and the Eastern network. The resulting marginal cost in each BAA will only differ because of the losses that occur on the West DC Ties. When there is not available capacity of flow on any of the West DC Ties, the next increment of load within each BAA must be served from within that BAA. Therefore, the marginal Resource(s) within each BAA will determine the marginal cost of serving load within that BAA.

Question 5

In your transmittal, you state that you will optimize the West DC Ties within the Integrated Marketplace.[27]

Please explain whether, and if so, how, the LMPs on the two sides of the West DC Ties will inform how SPP optimizes the use of those interties. If not, please explain how SPP will determine the optimal use of the West DC Ties.

Question 5 Response:

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26 Tariff at Attachment AE, Section 8.3.1.3.

27 *Id.* at 5.

The LMP on the two sides of each West DC Tie will not inform how SPP optimizes the use of the interties. Rather, SPP will determine the optimal use of the West DC Ties and the LMPs through the simultaneously co-optimized market solution that is used to minimize production cost.

Market dispatch across the West DC Ties is driven by the forward-looking economics in each BAA. SPP will determine the optimal use of each West DC Tie through the use of Security Constrained Unit Commitment ("SCUC")[28] and Security Constrained Economic Dispatch ("SCED")[29] to meet system requirements on a least cost basis. SPP will optimize the direction of the flow across each West DC Tie through the SCUC process and optimize the volume of the flow across each West DC Tie through the SCED process.

The SCUC is an algorithm that commits Resources while maintaining operating limits to meet system obligation and Operating Reserve requirements based on the topology, system, and Resource constraints on a least cost basis. With the proposed RTO Expansion, SCUC will now include constraints for topology, system, and Resources for each BAA and the West DC Tie operational constraints. As a result, SCUC will determine the direction of the flow across each West DC Tie. During the Day-Ahead Market process, the SCUC will optimize an initial direction for each West DC Tie. As real-time approaches, the SCUC will continue to evaluate the optimal direction of the flow across each West DC Tie during each RUC process, which occurs at least every four hours.

The SCED is an algorithm that dispatches, clears, and prices Energy and Operating Reserve to meet system obligations and Operating Reserve requirements based on the topology, system, and Resource constraints on a least cost basis. With the proposed RTO Expansion, SCED will now include constraints for topology, system, and Resources for each BAA and the West DC Tie operational constraints. As a result, SCED will determine the volume of the flow across each West DC Tie for every five-minute interval.

Question 6

6. In your transmittal, you state that Schedules 7 and 8 of the Tariff detail the rates associated with firm point-to-point transmission service and non-firm point-to-point service, respectively; Schedule 11 of the Tariff details Base Plan Zonal Charges and Region-Wide Charges; and Attachment L details the payment and distribution of revenues. The proposed revisions to Schedules 7 and 8 provide that, for point-to-point transmission service where the load is located "within a Balancing Authority Area external to the SPP Region and interconnected to the SPP

[28] Tariff at Attachment AE, Section 1.1 S (Definition of Security Constrained Unit Commitment).

[29] Tariff at Attachment AE, Section 1.1 S (Definition of Security Constrained Economic Dispatch).

West Region," the transmission customer will pay the SPP West Region's average zonal rate (per kW of reserved capacity).[30] The proposed revisions to Schedules 7 and 8 further provide that, for point-to-point transmission service where the load is located "within a Balancing Authority Area external to the SPP Region and interconnected to the SPP East Region," the transmission customer will pay the zonal rate for the pricing zone interconnected with such external Balancing Authority Area or, where more than one zone is interconnected to the external Balancing Authority Area, the lowest zonal rate of the interconnected zones.[31] The proposed revisions to section III.A of Schedule 11 provide that the Base Plan Zonal Charge will be assessed to transmission customers taking point-to-point transmission service and, where load is "located within a Balancing Authority Area external to the SPP Region and interconnected" to either the SPP East Region or the SPP West Region, the transmission customer will pay the Base Plan Average Zonal Rate (per kW of reserved capacity) in the SPP East Region or the SPP West Region, respectively.[32] Section II.C.2 of Attachment L provides for the distribution of revenues for point-to-point transmission service where the generation source(s) and load(s) are located *within a single zone*. The proposed revisions in section II.C.3 include provisions for the distribution of revenues for point-to-point transmission services in all instances other than that described in section II.C.2, but only for service "sinking in the SPP East Region" or "sinking in the SPP West Region."[33] Similarly, section III.B of Schedule 14 provides that a DC Tie Access Charge will be assessed to transmission customers taking firm point-to-point transmission service when the transmission service request utilizes a West DC Tie, for "service into or within the SPP Region" and for "service where the load is located within a Balancing Authority Area external to the SPP Region and interconnected to" either the SPP East Region or the SPP West Region.[34]

a. Please explain, under the proposed revisions to Schedules 7 and 8 of the Tariff, what rate(s) would apply to point-to-point transmission service over the SPP transmission system where the load is located within a BAA external to the SPP Region but *not* interconnected to the SPP East Region or the SPP West Region, and please identify and explain any applicable provisions in the revised Tariff that would apply to this situation.

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30 Proposed Tariff at Schedule 7, § 1; *id.*, Schedule 8, § 1.

31 *Id.*, Schedule 7, § 1; *id.*, Schedule 8, § 1.

32 *Id.*, Schedule 11, § III.A.

33 *Id.*, attach. L, § II.C.3.

34 *Id.*, Schedule 14, § III.B; *see id.*, pt. I, § 1 (defining DC Tie Access Charge as a "charge on a transmission reservation utilizing a West DC Tie that sinks outside of the Zone where the West DC Tie is located. The Transmission Customer shall be responsible for DC Tie Access Charge determined in accordance with Schedule 14.").

b. Please explain, under the proposed revisions to Schedule 11 of the Tariff, what rate(s) would apply to point-to-point transmission service over the SPP transmission system where the load is located within a BAA external to the SPP Region but *not* interconnected to the SPP East Region or the SPP West Region, and please identify and explain any applicable provisions in the revised Tariff that would apply to this situation.

c. Please explain, under proposed Schedule 14, what DC Tie Access Charge would apply to point-to-point transmission service over the SPP transmission system where the load is located within a BAA external to the SPP Region but *not* interconnected to the SPP East Region or the SPP West Region, and please identify and explain any applicable provisions in the revised Tariff that would apply to this situation.

d. Please explain how revenues from point-to-point transmission service—where the load is external to the SPP East Region and SPP West Region—will be distributed and identify any applicable provisions under the revised Tariff that would apply to this situation.

Question 6 Response:

6.a:

SPP Transmission Service charges apply for use of only the SPP Transmission System regardless of the location for the ultimate delivery to end-use load. Because any additional transmission service arrangements that a Transmission Customer needs beyond the SPP Region are not the responsibility of SPP, the point at which any "through and out" Transmission Service exits the SPP Region is the relevant information for SPP Transmission Service charges under Schedule 7 or 8. Moreover, it is not feasible for SPP to transmit power to a Point of Delivery that is not interconnected with the SPP Transmission System. Stated another way, from an SPP Transmission Service perspective, the external load is located at the designated Point of Delivery and that Point of Delivery must be interconnected with the SPP Transmission System.

The purpose of the proposed revisions to Schedules 7 and 8 of the Tariff is to distinguish between charges for Point-To-Point Transmission Service that ultimately exits the SPP Region from the SPP East Region versus from the SPP West Region. For service exiting from the SPP Region via the SPP West Region, the applicable Schedules 7 and 8 rate is based on an average for all the Zones in the SPP West Region. However, for service exiting from the SPP Region via the SPP East Region, the applicable Schedules 7 and 8 rate is dependent upon the location at which the Point-To-Point Transmission Service exits the SPP Region. For such Transmission Service exiting from the SPP East Region, the Transmission Customer shall pay the least cost zonal rate of the Zones interconnected with the designated Point of Delivery external to the SPP region, which as noted above, must be interconnected with the SPP Transmission System.

In the proposed Tariff language changes for Schedules 7 and 8, SPP uses the term "Balancing Authority Area" to refer to the Point of Delivery, which for through and out Transmission Service is outside of the SPP Region but interconnected with the SPP Transmission System. However, the proposed language does not specifically use the term "Point of Delivery." In contrast, the currently effective language in Schedule 7 and Schedule 8 uses the term "Point of Delivery" to clarify its application of "Balancing Authority Area." Additionally, in the proposed Tariff language modifications for Schedules 7 and 8, SPP use the phrase, "within a Balancing Authority Area external to the SPP Region and interconnected," in describing the case of a Transmission Service reservation which exits the SPP Region. Although this phrase is accurate, the description can be further simplified. In order to clarify both of these issues in the proposed language, SPP is willing to implement additional changes to Section 1 of Schedule 7 and Section 1 of Schedule 8, as shown in Exhibit No. SPP-0002 of this response, by means of a compliance filing. Utilizing the term "Point of Delivery" emphasizes the fact that the relevant factor in rate determination under Schedules 7 and 8 is the location to which SPP *delivers* power with its Transmission Service.

6.b:

Please see the response to question 6.a.

The zonal rate charged under Schedule 11 for Point-To-Point Transmission Service that exits the SPP Region, either from the SPP East Region or from the SPP West Region, will be determined based on the average for all the Zones in the SPP East Region or the average for all the Zones in the SPP West Region, respectively.[35] The region-wide rate charged under Schedule 11 for Point-To-Point Transmission Service that exits the SPP Region, either from the SPP East Region or from the SPP West Region, will be determined based on the aggregate for all regionally allocated facilities in the SPP East Region or the aggregate for all regionally allocated facilities in the SPP West Region, respectively.[36] Therefore, the specific Balancing Authority Area of delivery for Transmission Service exiting from the SPP East Region or SPP West Region is not a consideration in rate determination, but rather the rate is determined based on the more general consideration of whether the Transmission Service exits the SPP Region from the SPP East Region or SPP West Region, using applicable rate components for each.

As explained in the response to question 6.a, the phrase, "within a Balancing Authority Area external to the SPP Region and interconnected," can be expressed in a simpler and more direct fashion to describe Transmission Service that exits the SPP Region. In order to clarify the proposed language, SPP is willing to implement additional changes to Section III.A of Schedule 11, as shown in Exhibit No. SPP-0003 of this response, by means of a compliance filing.

6.c:

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35 Proposed Tariff at Section III.A of Schedule 11.

36 Proposed Tariff at Section III.B of Schedule 11.

Please see the response to question 6.a.

The Transmission Customer shall pay a DC Tie Access Charge when that Transmission Customer's Transmission Service request utilizes a West DC Tie. The DC Tie Access Charge applied to such service shall be the applicable rate for the West DC Tie utilized for the Transmission Service. However, because the DC Tie Access Charge is adjusted to prevent double charges when the applicable Schedule 7 charges include the West DC Tie ATRR, the locational basis for Schedule 7 charges is also the relevant locational basis for the DC Tie Access Charge adjustment.

For Transmission Service traversing the SPP Transmission System, and utilizing a West DC Tie, to serve load located external to the SPP Region and exiting from the SPP East Region, the Transmission Customers pay the least cost interconnected zonal rate for Schedule 7 charges as described in the response to question 6.a. If the Zone that is the basis for the least cost interconnected zonal Schedule 7 rate includes the applicable West DC Tie ATRR, the DC Tie Access charge is adjusted to $0. If the Zone that is the basis for the least cost interconnected zonal Schedule 7 rate does not include the applicable West DC Tie ATRR, the applicable unadjusted DC Tie Access Charge applies.[37]

For Transmission Service traversing the SPP Transmission System, and utilizing a West DC Tie, to serve load located external to the SPP Region and exiting from the SPP West Region, the Transmission Customers pay the SPP West Region average zonal rate for Schedule 7 charges. Because the SPP West Region average zonal rate includes the applicable West DC Tie ATRR, the applicable DC Tie Access Charge is adjusted to account for revenues distributed to the West DC Tie Transmission Owner from Schedule 7 recovery of the DC Tie ATRR's proportion of the average rate applied to through and out service from the SPP West Region for the same service.[38]

As explained in the response to question 6.a, the phrase, "within a Balancing Authority Area external to the SPP Region and interconnected," can be expressed in a simpler and more direct fashion to describe Transmission Service that exits the SPP Region. In order to clarify the proposed language, SPP is willing to implement additional changes to Subsections III.B.2 and III.B.3 of Schedule 14, as shown in Exhibit No. SPP-0004 of this response, by means of a compliance filing.

6.d:

Revenue under Schedules 7 and 8:

Revenue under Schedules 7 and 8 that is collected for Point-To-Point Transmission Service which exits the SPP Region from the SPP East Region is to be distributed to Transmission Owners under the provisions of Subsection II.C.3.a of Attachment L and revenue under Schedules 7 and 8 that is collected for Point-To-Point Transmission Service which exits the SPP Region from the SPP West Region is to be distributed to Transmission Owners under the provisions of Subsection II.C.3.b of Attachment L. In other words, such revenue is to be distributed with the same methodology that is used for any Point-To-Point Transmission Service that does not source and sink within a single

37 Proposed Tariff at Section III.B.2 of Schedule 14.

38 Proposed Tariff at Section III.B.3 of Schedule 14.

Zone. However, the proposed language in these two subsections does not explicitly address Transmission Service which exits the SPP Region. In order to ensure that Schedule 7 and 8 revenue distribution for Transmission Service that exits the SPP Region is addressed explicitly, SPP is willing to implement additional changes to Subsections II.C.3.a and II.C.3.b of Attachment L, as shown in Exhibit No. SPP-0005 of this response, by means of a compliance filing.

Revenue under Schedule 11:

All revenue under Schedule 11, from both Point-To-Point Transmission Service and Network Integration Transmission Service, is to be distributed to Transmission Owners under the provisions of Section III of Attachment L. These provisions, which are based on revenue distribution in proportion to the revenue requirements of Schedule 11 Network Upgrades, do not require separate treatment of Schedule 11 revenue derived from Point-To-Point Transmission Service which exits the SPP Region.

Revenue under Schedule 14:

All revenues received by the Transmission Provider associated with the DC Tie Access Charge pursuant to Schedule 14 of this Tariff shall be distributed to the applicable West DC Tie Transmission Owner(s) under Section IV.13 of Attachment L. This includes any such DC Tie Access Charge revenue received from Point-To-Point Transmission Service that exits the SPP Region.