



KENTUCKY MUNICIPAL ENERGY AGENCY

2020

INTEGRATED RESOURCE PLAN 2020-2042

Approved by the Board of Directors July 21, 2021.

Message from our President/CEO and Chairman

KYMEA provides wholesale power and energy services to eleven municipal electric systems throughout the Commonwealth of Kentucky. KYMEA exists to serve its members, is governed by its members, and its resource mix is a mutual decision collaboratively made by its members.

The KYMEA business model is to provide cost-effective resources and services for the benefit of its member communities to enable them to achieve objectives they have set for themselves more efficiently and at lower costs than they could achieve individually. The Agency balances competitive wholesale power rates with strong fiscal responsibility and operational excellence.

This Integrated Resource Plan (IRP2020) developed a strategy for KYMEA to meet its near-term power demand. IRP2020 also provides a 20-year blueprint on how KYMEA can best succeed in meeting the future demand for power. The plan provides the next chapter in KYMEA's ongoing success in a continually changing industry and regulatory environment, and better positions KYMEA to meet many of the challenges facing the power sector in the coming years.

In developing IRP2020, KYMEA enlisted the help of subject matter experts and the public at large to ensure we considered a wide range of resource options and a wide breadth of plausible resource plans. Today, the pace of change within the utility industry is staggering. Integrated Resource Planning efforts like this are essential in how KYMEA broadens its view of the future in an ever-changing world.



Josh Callihan
Chairman of the Board



Doug Buresh
President and CEO



Ron Herd
Past Chairman of the Board



Acknowledgments

When KYMEA was formed in September 2015, the Agency worked through numerous resource planning and modeling processes that created KYMEA's initial power supply portfolio. The Agency went operational and began delivering power on May 1, 2019.

IRP2020 is KYMEA's first formal IRP process that included public participation and a published report. Creating IRP2020 was a formidable exercise, which involved extensive research, community focus groups, and detailed analysis. I am very proud of the Agency's commitment and desire to produce a best-in-class work product.

I want to extend my sincere appreciation to the KYMEA Board of Directors for their support and guidance. I also would like to extend my gratitude to the following organizations and individuals that contributed to IRP2020.

- **NewGen Strategies & Solutions:** Development of the load forecast, transmission analysis
- **nFront Consulting and ACES Power Marketing:** Power supply and market subject matter experts
- **Rubin & Hays and Spiegel & McDiarmid:** Regulatory and legal experts
- **Horizons Energy:** Development of the scenarios and commodity projections
- **Anchor Power Solutions:** EnCompass technical and modeling support
- **RWE and Boyd CAT:** Guest presentations at the Community IRP Focus Group
- **Hatfield Media:** Community IRP Focus Group support

And finally, to the KYMEA staff who spent countless hours researching, analyzing, and composing the Integrated Resource Plan. I thank each one of you for making our first IRP a great success.

Thank you,



Doug Buresh
President and CEO

KYMEA Resource Planning Team:

Michelle Hixon
Heather Overby

Rob Leesman
Molly Roesler



TRANSPARENCY AND TRADE SECRET INFORMATION

As a public power agency, KYMEA strives to provide openness and transparency in its integrated resource planning process. KYMEA is pleased to present IRP2020 to the public without redactions and with full disclosure of the methods and techniques used to perform the analysis.

However, some of the information, such as request for proposals (RFP) responses, certain power supply costs, and market projections, are treated as valuable trade secrets with strict internal procedures to protect information obtained through non-disclosure agreements (NDA), and to maintain the privacy of this information where disclosure of this information would have severe competitive and legal implications for KYMEA. The opinions expressed in this report are based on KYMEA's judgment and analysis of key factors expected to affect the outcomes of future resource plans based on the best information available at the time the IRP2020 was conducted.

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Table of Contents

1.	EXECUTIVE SUMMARY	3
1.1	KYMEA's Overarching Power Supply Planning Priorities.....	3
1.2	Additional Board Direction – Current Planning Cycle	6
1.3	Near-Term Capacity and Energy Needs	7
1.4	Selection of Supply Options	8
1.5	Risk Assessment	9
1.6	Preferred Plan Selection – PLAN E.....	11
2.	KYMEA OVERVIEW	19
2.1	KYMEA's Vision, Mission, and Values	21
2.2	IRP2020 Participants	23
3.	IRP OBJECTIVES AND PROCESS	27
4.	EXISTING SYSTEM	35
4.1	KYMEA System Description.....	35
4.2	Loads and Load Growth	38
4.3	AR Project Initial Resource Portfolio.....	39
4.4	KYMEA Transmission	41
4.5	Transmission and Resource Risks.....	43
5.	LOAD FORECAST	47
5.1	Forecast Methodology Overview.....	47
5.2	KYMEA Member Individual Forecasts.....	52
5.3	KYMEA Combined Member Forecasts	76
5.4	COVID-19 Pandemic.....	83
5.5	Hourly Load Shapes.....	85
5.6	Annual Load Forecasts.....	86
6.	RESOURCE OPTIONS.....	91
6.1	Analysis of U.S. & Kentucky Resources	92
6.2	Coal Generation	97
6.3	Nuclear Generation	103
6.4	Geothermal Generation	111
6.5	Natural Gas Generation	115
6.6	Biomass Generation.....	122
6.7	Hydrogen Generation.....	127



6.8	Hydroelectric Generation	129
6.9	Wind Generation	135
6.10	Utility-Scale Solar Generation	142
6.11	Battery Storage	150
6.12	Other Energy Storage	154
6.13	Distributed Generation	162
6.14	Demand Side Management	167
6.15	Resource Cost and Performance.....	170
7.	ENVIRONMENTAL.....	179
7.1	Clean Air Act - Six Common Air Pollutants.....	180
7.2	Clean Air Act - Regulations.....	181
7.3	Regulating Power Sector Carbon Emissions.....	185
7.4	Tracking Subregion Emissions.....	189
8.	TRANSMISSION & DISTRIBUTION	195
8.1	Access to Markets.....	196
8.2	Buy/Drive-Out Rate Through MISO, PJM, & TVA	199
8.3	Distribution System.....	203
9.	PLANNING SOFTWARE & DATA SOURCES.....	207
9.1	Power Planning Software.....	207
9.2	Encompass Simulations	208
9.3	External Data Sources	210
10.	SCENARIO DEVELOPMENT	213
10.1	Scenario Themes	214
10.1.1	Status Quo Storyline.....	215
10.1.2	High Natural Gas Storyline	219
10.1.3	Low Natural Gas Storyline.....	222
10.1.4	High Demand Storyline	225
10.1.5	Low Demand Storyline	228
10.1.6	Zero Carbon Additions Storyline	231
10.1.7	High Natural Gas with Carbon Limit Storyline.....	235
10.1.8	Low Natural Gas with Carbon Limit Storyline.....	237
10.1.9	National Carbon Tax Storyline	239
10.2	Scenario Summary.....	241
11.	SCENARIO MARKET PRICE FORMATION	245
11.1	Modeling and Market Approach.....	245
11.2	EnCompass Market Simulation Module.....	246
11.3	Horizons Energy National Database	249



11.4	Definition of Spot and Forward Prices	251
11.5	Capacity and Scarcity Pricing.....	255
11.6	Natural Gas Markets.....	259
11.7	Coal Markets	264
12.	SCENARIO RESULTS	269
12.1	Resource Mix.....	270
12.2	Power Sector Fuel Consumption	276
12.3	Carbon.....	278
12.4	Additions & Retirements	288
12.5	Energy, Capacity, & Ancillary Service Prices	294
13.	PLAN DEVELOPMENT	301
13.1	Modeling Approach.....	301
13.2	Capacity Supply/Demand Balance	302
13.3	Near-Term Resource Plan.....	304
13.4	Long-Term Resource Plan	315
13.5	Decarbonization.....	321
13.6	Distributed Energy Resources (DER)	327
13.7	Demand-Side Options.....	328
14.	UNCERTAINTY & RISK	331
14.1	Measuring Risks.....	331
14.2	Near-Term Plan Selection - Sensitivity Analysis	333
14.3	Long-Term Plan Selection - Scenario Analysis.....	337
14.4	Selected Plan Hedging - Stochastic Analysis.....	338
14.5	EIA Annual Energy Outlook 2020	345
14.6	Mid-Term Uncertainties	350
14.7	Intra-Month (Daily/Hourly) Uncertainties.....	356
14.8	Stochastic Hourly Price Trajectories	358
14.9	Risk Analysis Metrics	359
14.10	Selected Plan Reliability - Stress Analysis.....	361
15.	PLAN EVALUATION	367
15.1	Evaluation Approach.....	367
15.2	Near-Term Plan Evaluation	369
15.3	Long-Term Plan Evaluation	381
16.	PLAN SELECTION	397
16.1	Selection Approach.....	397
16.2	Preferred Plan Selection - PLAN E.....	398
16.3	Ashwood Solar I Project Discussion	402



16.4 Preferred Plan Selection - Pivot to PLAN K 404

17. ACTION PLAN 413

17.1 Near-Term Power Supply Action Plan 413

17.2 Long-Term Action Plan 415

18. ACRONYMS & GLOSSARY 421

18.1 Acronyms 421

18.2 Glossary..... 424



List of Tables

Table 1.1-1: KYMEA Resource Details	4
Table 2.2-1: IRP2020 Participant Demographics	23
Table 4.2-1: KYMEA FY 2019/2020 Load and Peak Summary	38
Table 4.3-1: KYMEA Resource Details	39
Table 4.4-1: KYMEA Resource Transmission Portfolio	41
Table 4.4-2: Member Primary Voltage and Delivery Points	42
Table 4.5-1: Transmission Service Reservation Priorities	43
Table 4.5-2: KYMEA Resource Risk	44
Table 5.2-1: Barbourville – Regression Equation Detail	52
Table 5.2-2: Barbourville – Forecast (kW and kWh)	53
Table 5.2-3: Bardwell – Regression Equation Detail	54
Table 5.2-4: Bardwell – Forecast (kW and kWh)	54
Table 5.2-5: Benham – Regression Equation Detail	56
Table 5.2-6: Benham – Forecast (kW and kWh)	56
Table 5.2-7: Berea – Regression Equation Detail	58
Table 5.2-8: Berea – Forecast (kW and kWh)	58
Table 5.2-9: Corbin – Regression Equation Detail	60
Table 5.2-10: Corbin – Forecast (kW and kWh)	60
Table 5.2-11: Falmouth – Regression Equation Detail	62
Table 5.2-12: Falmouth – Forecast (kW and kWh)	63
Table 5.2-13: Frankfort – Res-Comm Regression Equation Detail	64
Table 5.2-14: Frankfort – Res-Comm Regression Equation Detail	64
Table 5.2-15: Frankfort – Industrial Regression Equation Detail	65
Table 5.2-16: Frankfort – Mun-Misc Regression Equation Detail	65
Table 5.2-17: Frankfort – Res-Comm Regression Equation Detail	65
Table 5.2-18: Frankfort – Forecast (kW and kWh)	66
Table 5.2-19: Madisonville – Residential Regression Equation Detail	68
Table 5.2-20: Madisonville – Res-Customer Count Regression Equation Detail	68
Table 5.2-21: Madisonville – Comm-Ind-Mun Regression Equation Detail	69
Table 5.2-22: Madisonville – Comm-Ind-Mun Customer Count Regression Equation Detail	69
Table 5.2-23: Madisonville – Large Industrial Customer Regression Equation Detail	69
Table 5.2-24: Madisonville – Forecast (kW and kWh)	70
Table 5.2-25: Paris – Regression Equation Detail	72
Table 5.2-26: Paris – Forecast (kW and kWh)	72
Table 5.2-27: Providence – Regression Forecast Detail	74
Table 5.2-28: Providence – Forecast (kW and kWh)	74
Table 5.3-1: AR Group – Summed NCP and CP Annual Demand Actuals and Forecast Results	76
Table 5.3-2: AR Group – Annual and Forecast Energy Sales	78
Table 5.3-3: IRP Participants – Summed NCP and CP Annual Demand Actuals and Forecast Results	80
Table 5.3-4: IRP Participants – Annual and Forecast Energy Sales	81
Table 5.6-1: KYMEA Annual Load Forecast (MW and MWh)	86
Table 6.1-1: U.S. Utility-Scale Electricity Generation by Source, Amount, and Share of Total in 2020	92
Table 6.15-1: Cost and Performance Summary Table (Sargent & Lundy)	170



Table 6.15-2: Cost and Performance Lithium-Ion Summary Table.....	171
Table 6.15-3: Cost and Performance Hydrogen Summary Table.....	172
Table 6.15-4: Cost and Performance Pumped Storage Summary Table.....	173
Table 6.15-5: Cost and Performance Compressed Air Energy Storage Summary Table	174
Table 6.15-6: Solar, Wind, and Battery Price Outlook Table	175
Table 8.1-1: Transmission Service Reservation Priorities	197
Table 8.1-2: Member's BA and Delivery Voltage.....	197
Table 8.1-3: KYMEA's Transmission Portfolio	198
Table 8.2-1: LG&E/KU Transmission Rates Table	199
Table 8.2-2: MISO Transmission Rates Table	199
Table 8.2-3: PJM Transmission Rates Table	200
Table 8.2-4: TVA Transmission Rates Table.....	200
Table 10.1.9-1: 116th Congress Carbon Legislation	240
Table 10.2-1: Scenario Drivers	241
Table 10.2-2: Scenario Descriptions.....	242
Table 13.3-1: Near-Term Resource Plans	311
Table 13.4-1: Long-Term Resource Plans.....	315
Table 13.6-1: KYMEA Member Net Metering Customers.....	327
Table 14.5-1: AEO2020 Economic Growth Cases.....	346
Table 14.6-1: Peak and Energy Standard Deviations	355
Table 15.2-1: Near-Term Plan Results	370
Table 15.2-2: Near-Term Plan Results Compared to Lowest-Cost 15 MW PTP Plan	371
Table 15.2-2: Near-Term Plan Results Compared to Lowest-Cost 40 MW PTP Plan	371
Table 15.2-3: Near-Term Plan N-1 Contingency Operating Reserve (Minimum MISO PTP)	378
Table 15.2-4: Near-Term Plan N-1 Contingency Operating Reserve (Maximum MISO PTP).....	379
Table 15.3-1: Long-Term Plan Results (levelized ¢/kWh)	381
Table 15.3-2: Long-Term Plan Results as Percentage of Least-Cost Plan	381



List of Figures

Figure 1.1-1: IRP Objectives and Metrics	3
Figure 1.1-2: Capacity Supply/Demand Balance.....	5
Figure 1.3-1: Near-Term Energy Needs.....	7
Figure 1.4-1: IRP Flowchart	8
Figure 1.5-1: Risk Analysis Quadrants	9
Figure 1.5-2: KYMEA Scenario Roadmap	10
Figure 1.6-1: PLAN E and PLAN K Comparison	12
Figure 1.6-2: Mix of Energy Resources to Serve KYMEA Load	14
Figure 1.6-3: PLAN E and PLAN K Carbon Intensity	15
Figure 2-1: Eleven KYMEA Members.....	20
Figure 2.2-1: IRP2020 Participant Counties	24
Figure 3-1: IRP Objectives and Metrics.....	27
Figure 3-2: Least-Cost Planning Flowchart	30
Figure 4.1-1: LG&E/KU and Surrounding Balancing Authorities.....	35
Figure 4.1-2: The TVA Fence Map	36
Figure 4.1-3: Kentucky Balancing Authority Map	37
Figure 4.3-1: KYMEA Resource Map	39
Figure 4.4-1: KYMEA IRP2020 Participant Map	42
Figure 5.1-1: Relationship Between Average Temperature and Electric Usage.....	48
Figure 5.1-2: Binary Variable Utilized to Mitigate Trends in Residuals.....	50
Figure 5.2-1: Barbourville - Forecast Graph	53
Figure 5.2-2: Bardwell – Forecast Graph.....	55
Figure 5.2-3: Benham – Forecast Graph.....	57
Figure 5.2-4: Berea – Forecast Graph	59
Figure 5.2-5: Corbin – Forecast Graph.....	61
Figure 5.2-6: Falmouth – Forecast Graph	63
Figure 5.2-7: Frankfort – Forecast Graph	67
Figure 5.2-8: Madisonville – Forecast Graph.....	70
Figure 5.2-9: Paris – Forecast Graph.....	73
Figure 5.2-10: Providence – Forecast Graph.....	75
Figure 5.3-1: AR Group – Forecast Graph	77
Figure 5.3-2: AR Group – Forecast Graph with Weather Normalized Actuals.....	78
Figure 5.3-3: AR Group – Forecast Graph	79
Figure 5.3-4: IRP Participant Forecast Graph.....	81
Figure 5.3-5: IRP Participant Summed Energy Forecast Graph	82
Figure 5.4-1: Unemployment Rate During COVID-19 Pandemic	83
Figure 5.4-2: COVID-19 Load Impact – FY 2021 12-Month NCP and Energy	84
Figure 5.4-3: COVID-19 Assumed Load Recovery	84
Figure 5.5-1: KYMEA AR Project Coincident Load Shape	85
Figure 5.6-1: Summer Peak and Net Peak Day.....	87
Figure 6.1-1: U.S. Electricity Generation by Fuel, All Sectors	93
Figure 6.1-2: Operable Utility-Scale U.S. Generating Units as of November 2020	93
Figure 6.1-3: Planned U.S. Utility-Scale Electric Generating Capacity Additions (2021)	94
Figure 6.1-4: Map of U.S. Electric Generating Capacity Additions (2021).....	95



Figure 6.1-5: Power Plants in Kentucky	96
Figure 6.2-1: Illustration Coal-Fired Power Plant.....	98
Figure 6.2-2: Carbon Capture and Storage Process	100
Figure 6.2-3: U.S. Coal Plant Retirements MW (2000-2042)	101
Figure 6.2-4: U.S. Coal Capacity MW	102
Figure 6.3-1: Nuclear Generation by Country 2019	103
Figure 6.3-2: U.S. Operating Commercial Nuclear Power Reactors.....	104
Figure 6.3-3: Pressurized Water Reactor (PWR) Diagram	105
Figure 6.3-4: Boiling Water Reactor (BWR) Diagram.....	106
Figure 6.3-5: License Renewal Process Flowchart	107
Figure 6.3-6: U.S. Commercial Nuclear Power Reactors - Yrs of Operation by End of 2020.....	108
Figure 6.3-7: U.S. Nuclear Capacity	109
Figure 6.4-1: Geothermal Resource Sites of the U.S.	111
Figure 6.4-2: Dry Steam Power Plant.....	112
Figure 6.4-3: Flash Steam Power Plant	112
Figure 6.4-4: Binary Cycle Power Plant.....	113
Figure 6.4-5: Existing Geothermal Energy in the U.S.	113
Figure 6.4-6: U.S. Geothermal Capacity (MW).....	114
Figure 6.5-1: Henry Hub Natural Gas Price and NYMEX Confidence Intervals	116
Figure 6.5-2: Simple Cycle Gas Plant Diagram	117
Figure 6.5-3: Combined Cycle Gas Plant Diagram.....	118
Figure 6.5-4: Reciprocating Engine Gas Plant Diagram	119
Figure 6.5-5: U.S. Natural Gas Capacity (MW)	121
Figure 6.6-1: Types of Biomass	122
Figure 6.6-2: 2019 U.S. Biomass Consumption	123
Figure 6.6-3: U.S. Biomass Capacity (MW)	124
Figure 6.6-4: Solid Biomass Resources in the U.S.	125
Figure 6.6-5: Kentucky Biomass Generation	126
Figure 6.7-1: Hydrogen Production Electrolysis.....	127
Figure 6.8-1: SEPA Cumberland River System Map.....	130
Figure 6.8-2: Illustration Hydroelectric Dam	132
Figure 6.8-3: 2020 National Hydropower Map.....	133
Figure 6.8-4: U.S. Hydropower Capacity (MW)	134
Figure 6.8-5: U.S. Non-powered Dams with Potential Capacity Greater than One Megawatt	134
Figure 6.9-1: Illustration Wind Turbines	135
Figure 6.9-2: U.S. Wind Capacity (MW).....	136
Figure 6.9-3: NREL U.S. Wind Prospector.....	137
Figure 6.9-4: U.S. Wind Power Capacity	138
Figure 6.9-5: U.S. Wind Potential.....	139
Figure 6.9-6: Kentucky Potential Wind Capacity.....	140
Figure 6.9-7: Wind Turbine Evolution in Land-Based Turbines.....	141
Figure 6.10-1: U.S. Solar Capacity (MW)	144
Figure 6.10-2: U.S. Horizontal Solar Irradiance	145
Figure 6.10-3: Solar ITC Schedule	146
Figure 6.10-4: Parameters Affecting Bifacial Production - RWE.....	149
Figure 6.11-1: Utility Scale Battery Storage Example	152



Figure 6.11-2: U.S. Large-Scale Battery Storage Cumulative Power Capacity (2010-2023)	153
Figure 6.12-1: Distribution of Energy Storage and other Renewable Power Plants in Lower 48 States	154
Figure 6.12-2: U.S. Utility-Scale Energy Storage Projects (December 2020).....	155
Figure 6.12-3: Open/Closed Loop Pumped Storage HydroPower Diagram	156
Figure 6.12-4: Licensed Pumped Storage Projects (2021)	157
Figure 6.12-5: Compressed Air Energy Storage Diagram.....	158
Figure 6.12-6: Flywheel Energy Storage Systems Diagram.....	159
Figure 6.12-7: Concrete Block Energy Storage Diagram	160
Figure 6.13-1: Rooftop Solar Panel	162
Figure 6.13-2: Distributed Generation Diagram.....	163
Figure 6.13-3: 2018 Net-Metering Installed Capacity (kW) by County.....	165
Figure 6.13-4: 2018 Non Net-Metered Installed Capacity (kW) by County	166
Figure 6.14-1: Efficiency and Demand Response Program Costs	167
Figure 6.14-2: Efficiency and Demand Response Savings	168
Figure 6.14-3: Actual Total Peak Demand Savings from Demand Response in 2017.....	168
Figure 7-1: Getting to Net-Zero Carbon Emissions by 2050.....	179
Figure 7.2-1: EPA Regulatory Timeline for Coal-Fueled Power Plants	183
Figure 7.2-2: States Covered by EPA Regulations	184
Figure 7.4-1: Map of eGRID Subregions - EPA.....	189
Figure 7.4-2: SRTV Subregion 2019 Generation Mix - eGRID.....	190
Figure 7.4-3: SRTV Subregion SO ₂ Emissions (lbs/MWh) - eGRID.....	191
Figure 7.4-4: SRTV Subregion NO _x Emissions (lbs/MWh) - eGRID.....	191
Figure 7.4-5: SRTV Subregion 2018 CO ₂ Emissions (lbs/MWh) - eGRID.....	192
Figure 7.4-6: Carbon Intensity	192
Figure 8-1: Diagram of Electricity Generation, Transmission, and Distribution System	195
Figure 8.1-1: U.S. Electric Power Regions.....	196
Figure 8.1-2: Kentucky BA Map	198
Figure 8.2-1: LG&E/KU Network Service (\$/kW-MO)	201
Figure 8.2-2: MISO Firm Point-to-Point (\$/kW-MO)	201
Figure 8.2-3: PJM Firm Point-to-Point (\$/kW-MO).....	202
Figure 8.2-4: TVA Firm Point-to-Point (\$/kW-MO)	202
Figure 8.3-1: Electric Power System.....	203
Figure 9.1-1: EnCompass Optimize Decisions Across Multiple Commodities.....	207
Figure 9.2-1: Horizons Energy National Database Topology.....	209
Figure 10.1-1: KYMEA Scenario Roadmap	213
Figure 10.1.1-1: Status Quo Timeline	215
Figure 10.1.1-2: U.S. Total Energy Production & Consumption Graph	216
Figure 10.1.1-3: Status Quo Scenario Natural Gas Price Graph.....	217
Figure 10.1.1-4: Status Quo Scenario North American Load Forecast Graph - Peak.....	218
Figure 10.1.1-5: Status Quo Scenario North American Load Forecast Graph - Energy.....	218
Figure 10.1.2-1: High Natural Gas Timeline.....	219
Figure 10.1.2-2: High Natural Gas - Weighted Average Delivered Cost.....	221
Figure 10.1.3-1: Low Natural Gas Timeline.....	222
Figure 10.1.3-2: Low Natural Gas - Weighted Average Delivered Costs.....	223
Figure 10.1.3-3: EIA Confidence Interval of Henry Hub.....	224
Figure 10.1.4-1: High Demand Timeline	225



Figure 10.1.4-2: Automakers Electric Future Timeline	226
Figure 10.1.4-3: High Demand - Peak Load Forecast.....	227
Figure 10.1.4-4: High Demand - Energy Load Forecast	227
Figure 10.1.5-1: Low Demand Timeline.....	228
Figure 10.1.5-2: Low Demand - Peak Load Forecast.....	230
Figure 10.1.5-3: Low Demand - Energy Load Forecast.....	230
Figure 10.1.6-1: Zero Carbon Additions Timeline	231
Figure 10.1.6-2: Zero Carbon BTM Generation (MW)	232
Figure 10.1.6-3: Zero Carbon - Energy Net Load After BTM (GWh)	232
Figure 10.1.6-4: States that Adopted 100% Renewable Goals/Targets	234
Figure 10.1.7-1: High Natural Gas Timeline.....	235
Figure 10.1.7-2: High Natural Gas with CO ₂ Limit - Weighted Average Delivered Nominal Price.....	236
Figure 10.1.8-1: Low Natural Gas Timeline.....	237
Figure 10.1.8-2: Low Natural Gas with CO ₂ Limit - Weighted Average Delivered Nominal Price.....	238
Figure 10.1.9-1: National Carbon Tax Timeline.....	239
Figure 10.1.9-2: U.S. Carbon Tax (\$/MWh).....	240
Figure 11.2-1: Energy and Ancillary Services Co-Optimization Flow	246
Figure 11.2-2: MISO Ancillary Services Map.....	248
Figure 11.3-1: MISO and Interconnected Zonal Markets.....	249
Figure 11.4-1: LGEE Hourly Spot Market Price Distribution	251
Figure 11.4-2: Zonal and Nodal Price Points of Interest.....	252
Figure 11.4-3: LGEE Over Indy.Hub Basis Factor	253
Figure 11.4-4: LGEE Monthly Spot Market Price Distribution	253
Figure 11.5-1: MISO Local Resource Zone Map.....	255
Figure 11.5-2: Retail Choice States in MISO	256
Figure 11.5-3: Potomac Economics Proposed MISO Sloped Demand Curve	257
Figure 11.5-4: Potomac Economics Proposed Economic ORDC.....	258
Figure 11.6-1: Natural Gas Market Centers - Horizons Energy.....	259
Figure 11.6-2: Shale Gas Plays	260
Figure 11.6-3: Federal Lands.....	261
Figure 11.6-4: LNG Export Capacity.....	262
Figure 11.6-5: U.S. Monthly and Annual Gas Exports by Pipeline and LNG (2016-2022).....	263
Figure 11.7-1: Deliveries from Major Coal Basins.....	264
Figure 11.7-2: MISO Central 2019 Energy Mix - MISO	265
Figure 12.1-1: Status Quo - North American Power Sector Mix (GWh)	270
Figure 12.1-2: High Natural Gas - North American Power Sector Mix (GWh).....	271
Figure 12.1-3: Low Natural Gas - North American Power Sector Mix (GWh)	271
Figure 12.1-4: High Demand - North American Power Sector Mix (GWh).....	272
Figure 12.1-5: Low Demand - North American Power Sector Mix (GWh).....	272
Figure 12.1-6: Zero Carbon - North American Power Sector Mix (GWh)	273
Figure 12.1-7: High Natural Gas with CO ₂ - North American Power Sector Mix (GWh).....	273
Figure 12.1-8: Low Natural Gas with CO ₂ - North American Power Sector Mix (GWh).....	274
Figure 12.1-9: Carbon Tax - North American Power Sector Mix (GWh)	274
Figure 12.1-10: Nine Scenarios - North American Energy Mix (2042).....	275
Figure 12.2-1: Natural Gas Power Sector Consumption	276
Figure 12.2-2: Coal Power Sector Consumption.....	277



Figure 12.3-1: Status Quo - U.S. Power Sector CO ₂ Emissions (MM short tons)	279
Figure 12.3-2: Status Quo - Power Sector Carbon Intensity (lb/MWh)	280
Figure 12.3-3: No Carbon Limit - U.S. Power Sector CO ₂ Emissions (MM short tons)	281
Figure 12.3-4: Nuclear Retirements - Impact on Carbon-Free Generation	282
Figure 12.3-5: High Natural Gas with Carbon Limit - CO ₂ Shadow Price	283
Figure 12.3-6: Low Natural Gas with Carbon Limit - CO ₂ Shadow Price	284
Figure 12.3-7: Carbon Tax (\$/MWh).....	285
Figure 12.3-8: Carbon Limit - U.S. Power Sector CO ₂ Emissions (MM short tons)	286
Figure 12.3-9: Carbon Limit - U.S. Power Sector Carbon Intensity (lb/MWh).....	287
Figure 12.4-1: CC, Wind, and Solar Capacity Additions (GW).....	288
Figure 12.4-2: CC, Wind, and Solar Energy Additions (TWh).....	289
Figure 12.4-3: Wind and Transmission Map	289
Figure 12.4-4: 2042 MISO Wind Capacity (GW)	290
Figure 12.4-5: 2013 EIPC Scenario 1 Transmission Expansion	291
Figure 12.4-6: MISO Firm Transmission Costs (\$/kW-MO)	292
Figure 12.4-7: Coal and Nuclear Retirements (GW).....	293
Figure 12.5-1: MISO-IN-KY Annual ATC Energy Prices (nominal \$/MWh).....	294
Figure 12.5-2: MISO-IN-KY Capacity Prices (nominal \$/kW-MO).....	295
Figure 12.5-3: MISO-IN-KY Spinning Reserve Prices (nominal \$/MWh).....	296
Figure 12.5-4: MISO-IN-KY Supplemental Reserve Prices (nominal \$/MWh).....	297
Figure 12.5-5: MISO-IN-KY Regulation-Up Prices (nominal \$/MWh)	297
Figure 12.5-6: MISO-IN-KY Regulation-Down Prices (nominal \$/MWh)	298
Figure 13.2-1: Capacity Supply/Demand Balance.....	303
Figure 13.3-1: Near-Term Energy Needs.....	304
Figure 13.3-2: RFP2020 Response Tree	306
Figure 13.3-3: Solar Saturation Graph.....	308
Figure 13.3-4: RFP2020 Decision and Uncertainty Tree.....	309
Figure 13.3-5: Near-Term Decision Elements	310
Figure 13.3-6: Benham and Berea Map	314
Figure 13.4-1: Long-Term PLAN 1: CC Map	316
Figure 13.4-2: Long-Term PLAN 2: RICE Map.....	317
Figure 13.4-3: Long-Term PLAN 3: Market Map	318
Figure 13.4-4: Long-Term PLAN 4: Net Zero Map	319
Figure 13.4-5: Battery Energy Storage Applications	320
Figure 13.5-1: Long-Term PLAN 5: Solar + Battery + Hydro Map	321
Figure 13.5-2: Long-Term PLAN 5: Battery Storage Level (MWh).....	322
Figure 13.5-3: Long-Term PLAN 5: Resource Distribution	323
Figure 13.5-4: Long-Term PLAN 6: Wind + Solar + Battery Storage + Hydro Map.....	324
Figure 13.5-5: Long-Term PLAN 6: Battery Storage Level (MWh).....	325
Figure 13.5-6: Long-Term PLAN 6: Resource Distribution	326
Figure 14.1-1: Risk Analysis Quadrants	332
Figure 14.2-1: Near-Term Plan Decision Tree with Sensitivity Analysis	333
Figure 14.2-2: Henry Hub NG Gas Price Sensitivity (nominal \$/MMBtu).....	334
Figure 14.2-3: LGEE ATC Energy Price Sensitivity (nominal \$/MWh).....	335
Figure 14.2-4: Bilateral Capacity Price Sensitivity (nominal \$/kW-MO).....	336
Figure 14.3-1: Long-Term Plan Decision Tree with Scenario Analysis	337



Figure 14.4-1: Latin Hypercube Density Function	339
Figure 14.4-2: Latin Hypercube Sampling for Two Variables.....	340
Figure 14.4-3: Probability Distributions.....	341
Figure 14.5-1: EIA National Energy Modeling System (NEMS).....	345
Figure 14.5-2: Long-Term Economic Demand Growth - 50 Draws (MWh)	347
Figure 14.5-3: Long-Term Natural Gas Uncertainty - 50 Draws (nominal \$/MMBtu)	349
Figure 14.6-1: Mid-Term Natural Gas Volatility (1994-2020).....	350
Figure 14.6-2: Mid-Term Natural Gas Volatility (Monthly).....	351
Figure 14.6-3: Mid-Term Natural Gas Log-Normal Distribution	352
Figure 14.6-4: Monthly Peak Volatility (2010-2019)	353
Figure 14.6-5: Monthly Energy Volatility (2010-2019)	354
Figure 14.7-1: Historical Load Duration Curves.....	356
Figure 14.7-2: Expected Daily Natural Gas Volatility.....	357
Figure 14.7-3: Low and High Daily Natural Gas Volatility.....	357
Figure 14.8-1: MISO-IN-KY Long-Term Market Prices - 50 Draws (nominal \$/MWh).....	358
Figure 14.9-1: Average Production Cost Risk Profile	359
Figure 14.9-2: Tornado Chart Example.....	360
Figure 14.10-1: The Science Behind the Polar Vortex	361
Figure 14.10-2: Two Main Types of Gas Delivery Services.....	362
Figure 14.10-3: ERCOT 2021 Polar Vortex Generator Outages by Cause (MW).....	364
Figure 15.2-1: KYMEA BA and Area Topology Map	369
Figure 15.2-2: Near-Term Plans - Base Market Comparison	372
Figure 15.2-3: Near-Term Plans - Lowest Cost and Lowest Risk.....	373
Figure 15.2-4: Near-Term Plans - Low Market Comparison.....	374
Figure 15.2-5: Near-Term Plans - High Market Comparison	375
Figure 15.2-6: Near-Term Plans - Expected Value and Market Risk Ranking.....	376
Figure 15.2-7: Near-Term Plans - Efficient Frontier	377
Figure 15.2-8: AR Project Peaks with Benham and Berea.....	380
Figure 15.3-1: Long-Term PLAN 1: CC Map	382
Figure 15.3-2: Long-Term PLAN 1: CC Results.....	383
Figure 15.3-3: Long-Term PLAN 2: RICE Map.....	384
Figure 15.3-4: Long-Term PLAN 2: RICE Results.....	385
Figure 15.3-5: Long-Term PLAN 3: Market Map	386
Figure 15.3-6: Long-Term PLAN 3: Market Results.....	387
Figure 15.3-7: Long-Term PLAN 4: Net Zero Map	388
Figure 15.3-8: Long-Term PLAN 4: Net Zero Results.....	389
Figure 15.3-9: Solar/Battery Utilization Per Season	390
Figure 15.3-10: KYMEA Plan CO ₂ Intensity Rate Comparison (lb/MWh)	391
Figure 15.3-11: KYMEA Plan SO ₂ Comparison (Tons)	392
Figure 15.3-12: KYMEA Plan NO _a Comparison (Tons).....	393
Figure 16.2-1: PLAN E - Spot Market Stress Test	399
Figure 16.2-2: PLAN E - Summer Season Operating Reserves.....	400
Figure 16.2-3: PLAN E - Winter Season Operating Reserves	401
Figure 16.3-1: Ashwood Solar Output and Intermittency	402
Figure 16.4-1: PLAN E and PLAN K Comparison	405
Figure 16.4-2: PLAN K - Summer Season Operating Reserves.....	406



Figure 16.4-3: PLAN K - Winter Season Operating Reserves..... 407

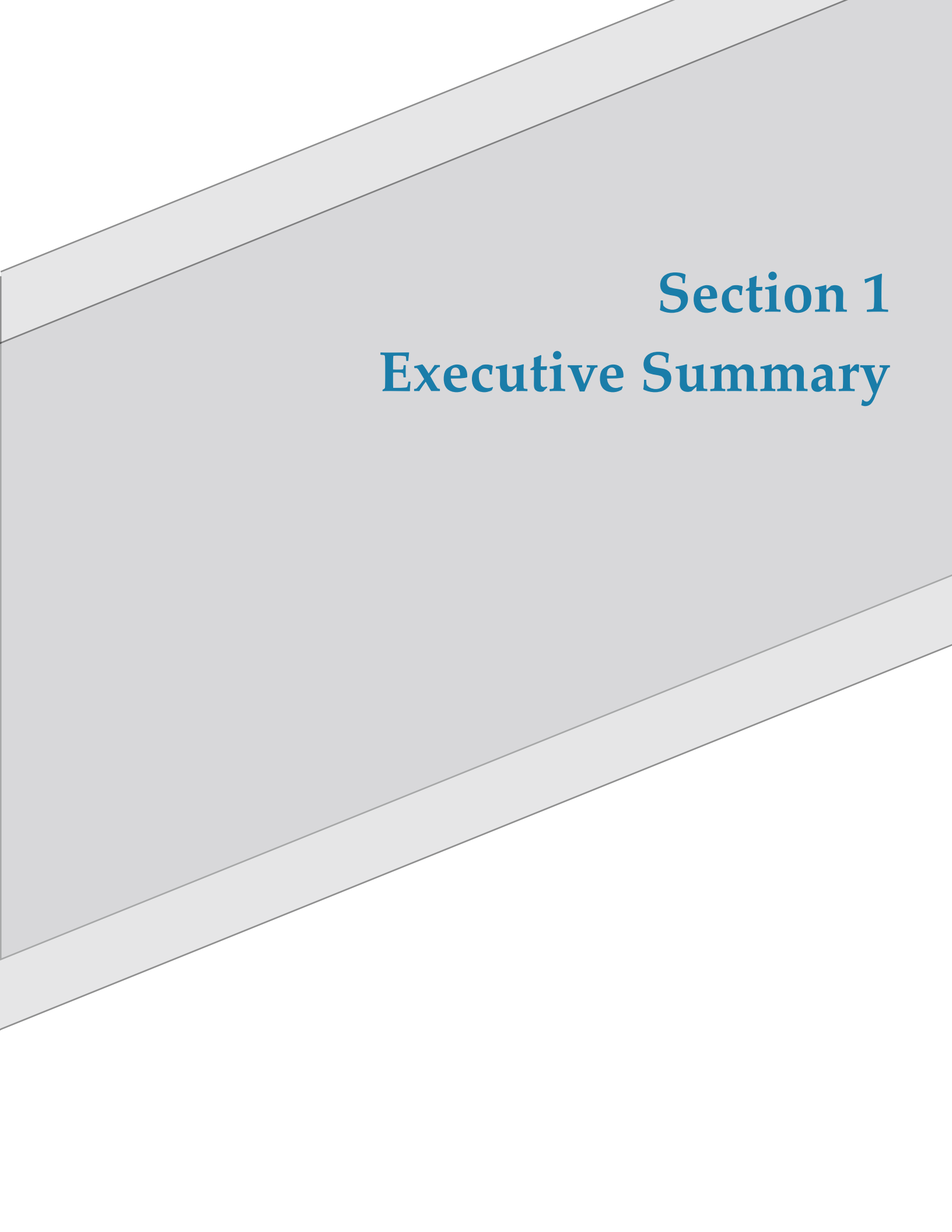
Figure 16.4-4: Mix of Energy Resources to Serve KYMEA Load 408

Figure 16.4-5: PLAN E and PLAN K Carbon Intensity 409

Figure 17.2-1: SEEM Footprint..... 415

Figure 17.2-2: Proposed Southeast Electric Highway Coalition 417

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Section 1

Executive Summary

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1. EXECUTIVE SUMMARY

1.1 KYMEA's Overarching Power Supply Planning Priorities

The Kentucky Municipal Energy Agency (KYMEA or the Agency) is a joint public agency formed to facilitate effective collaboration among its members to do all things necessary or convenient to:

- Serve the members' current and future electric power and energy requirements; and
- Assist members as requested with respect to their electric power and energy utility systems.

KYMEA has eleven (11) members and is governed by a board of directors to which each member appoints a Director and an Alternate Director. Each KYMEA member is a municipally-owned customer-serving electric distribution utility. As such, KYMEA exists to enable its load-serving members to jointly plan and act to meet the needs of their customers for electric service. The Board of Directors (Board) establishes rates and charges to recover KYMEA's costs and provide needed working capital and cash reserves. KYMEA does not provide returns to shareholders as is the case with many wholesale power suppliers.

Under the direction of its Board, KYMEA balances the following key priorities in planning its power supply portfolio.

- **Reliability** – Assure an ample supply of resources with transmission rights such that potential for curtailment is on par with other area suppliers.
- **Stable and competitive power supply costs** – Plan for and establish power supply resources to allow members to provide stable, affordable rates to customers and have a positive financial impact on their communities.
- **Environmental stewardship** – Responsibly manage the environmental impacts of KYMEA's power supply portfolio consistent with achieving a reliable, stable, and competitive power supply.

Over the past year, KYMEA's power supply planning effort has resulted in key decisions by its Board and the development of its 2020 Integrated Resource Plan (IRP2020) summarized herein.

To provide the information needed for the Board to consider the alignment of power supply options with its priorities, the IRP2020 has addressed the objectives and metrics summarized in Figure 1.1-1.

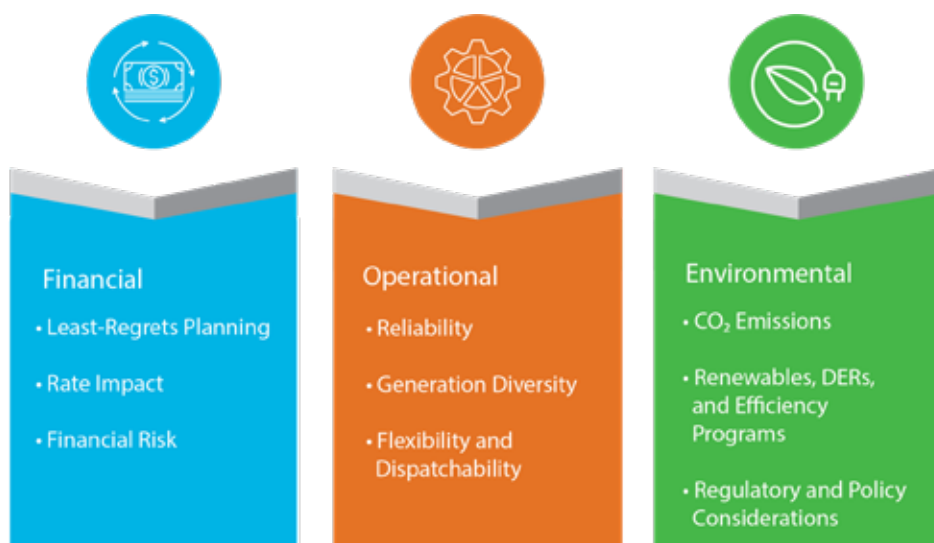


Figure 1.1-1: IRP Objectives and Metrics



Current Planning Focus - Near-Term Portfolio Changes

KYMEA's current planning cycle has been driven primarily by scheduled and potential changes in its existing power supply portfolio during the near-term period from June 2022 through May 2027.

KYMEA's existing power supply portfolio includes contracts under which KYMEA purchases power from multiple resources over various periods of time. The diversity of KYMEA's existing portfolio of contracts in terms of counterparty, type, location, and contract term was an intentional risk mitigation consideration of KYMEA's past power supply planning efforts.

Table 1.1-1 identifies KYMEA's existing resources. In addition, KYMEA has contracted to purchase 53.75 MW of the capability and associated energy from the Ashwood Solar I Project (Ashwood), currently under construction in Lyon and Caldwell counties, Kentucky. KYMEA's contract to purchase power from Ashwood extends for 20 years commencing upon the commercial operation date of the project, which is targeted for December 2022.

Table 1.1-1: KYMEA Resource Details

Resource	Fuel	Type	Capacity (MW)	Term End
BREC D.B. Wilson	Coal	PPA	100	May 31, 2029
IPMC Joppa	Coal	PPA	100	May 31, 2022
PPS Plant 1	Natural Gas	PPA	90	May 31, 2029
SEPA	Hydro	Member	32	
Paris	Diesel	PPA	11	May 31, 2029

In the near term, at least the following changes in KYMEA's power supply portfolio are either scheduled to occur or may occur.

- Contract for KYMEA's 100 MW purchase from Vistra's IPMC Joppa Plant (coal-fired) terminates at the end of May 2022.
- Commercial operation of Ashwood is expected to occur by December 2022, resulting in the commencement of power deliveries to KYMEA from its 53.75 MW share of the plant's capability.
- KYMEA may exercise an option to increase the capability taken from Ashwood from 53.75 MW to approximately 86 MW.¹
- KYMEA has a one-time option to reduce purchases from Paducah Power System's natural gas-fueled combustion turbine plant from 90 MW to as low as 30 MW beginning June 1, 2023.
- Benham and Berea² have the option to join the KYMEA AR Project to receive all requirements service commencing June 2024. Serving Benham and Berea would add approximately 10% to KYMEA's total energy requirements.

In the long-term planning period, at least the following changes in KYMEA's power supply portfolio are either scheduled to occur or may occur.

- Contract for KYMEA's 100 MW purchase from Big Rivers based on the cost of the D. B. Wilson Plant (coal-fired) terminates at the end of May 2029, subject to KYMEA's unilateral right to elect to extend the contract for an additional 10 years.

¹ KYMEA elected not to exercise that right in February 2021. A second opportunity to exercise that right may occur yet in 2021.

² Benham and Berea are currently transmission-only members of KYMEA and have participated in the IRP2020 process.



- Contract for KYMEA's 30 to 90 MW purchase from Paducah Power based on the cost of Paducah Power System's natural gas-fueled combustion turbine plant terminates at the end of May 2029 subject to KYMEA's unilateral right to elect to extend the contract for an additional 10 years.
- Contracts for KYMEA's purchase from Paris and SEPA member-owned generation terminate no earlier than the end of May 2029 and are subject to mutually agreed upon extension.

Currently, the resources in the portfolio known to extend beyond May 2029, including KYMEA's purchase of solar power from Ashwood, which has a 20-year term into 2042. In addition, KYMEA expects the members' SEPA purchases to continue to be available.³

Accordingly, KYMEA has prepared analyses of power supply options for the long-term period from June 2027 through May 2042. The analysis of long-term options was prepared to identify any potential actions that could be required in the near-term to implement power supply resources in that long-term period and to better inform the Agency of the options available for the longer term and the considerations that will impact decisions regarding the resource portfolio in that period. KYMEA has determined it should defer, for now, actions related to developing resources for the long-term period. Accordingly, the long-term period is addressed only at a very high level in this summary and will become the focus of future planning efforts.

Figure 1.1-2 depicts the load of KYMEA's members and the resources currently in the portfolio to serve that load. The impact of serving Benham's and Berea's loads is also shown.

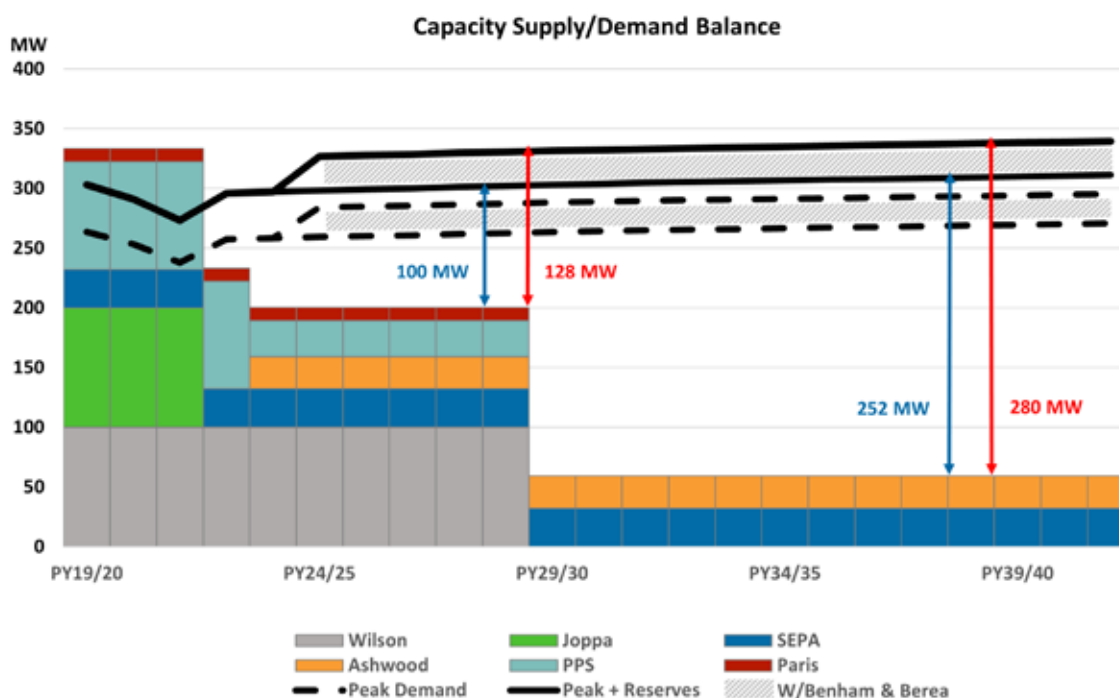


Figure 1.1-2: Capacity Supply/Demand Balance

³ KYMEA's members each have rights to terminate their individual contracts to purchase power from SEPA upon specified notice.



1.2 Additional Board Direction – Current Planning Cycle

KYMEA began serving the power supply requirements of its members in May 2019 – approximately two years ago.

Over the past year, KYMEA’s Board has made decisions consistent with the goals of the organization and the Federal Government policy-related uncertainties faced by all in the industry due to the recent change in Federal Government Administration. KYMEA’s Board can be expected to continue to evaluate options and priorities in these and other areas as more is known about the impacts of federal policy proposals targeting carbon and other emissions.

1. KYMEA’s Board has chosen options that avoid new power supply-related financial commitments any longer in term than are necessary to obtain reasonable pricing and mitigate exposure to market price volatility.
2. KYMEA’s Board decisions are intended to position KYMEA to use the competitive day-ahead and real-time MISO and PJM energy markets to the organization’s advantage without being overly dependent on market conditions for targeted financial outcomes.
3. KYMEA’s Board has directed KYMEA to focus on power supply options and assist with member demand-side programs in the future upon request.

Regarding demand-side resources, KYMEA is not directly responsible for managing relationships with the retail customers served by its members - relationships with retail customers are managed by the members. KYMEA is in a position to support members in evaluating and developing demand-side programs. KYMEA would then rely on demand-side programs in planning future power supply portfolios as commitments are made by members and the members’ customers to those programs.

The existing All Requirements Power Sales Contracts between each member and KYMEA provide for members to individually consider and potentially undertake feasible member-owned resources, net metering, and direct load control programs within parameters that avoid significant shifting of costs between members. The member-KYMEA contracts do not limit programs intended to make customer energy usage more efficient.

The significant trend toward more efficient appliances and equipment is reflected in the historical data used to forecast KYMEA member loads. In addition, KYMEA considers the sensitivity of planning decisions to load forecast uncertainties. Overall, KYMEA has substantial flexibility to adapt future power supply portfolios if and as new demand-side options are identified and implemented at the member level.



1.3 Near-Term Capacity and Energy Needs

As evidenced by the Capacity Supply/Demand Balance curve shown in Figure 1.1-2 on page 5, the overall AR Project additional capacity need, including reserves, is projected to be approximately 100 MW through Planning Year 2028/2029.

The Load Duration Curve analysis shown in Figure 1.3-1 illustrates that of the additional 100 MW capacity need, approximately 30 to 60 MW of intermediate capacity with energy would fill the void highlighted by the gray area. The intermediate block would satisfy nearly 25% of KYMEA’s energy needs. It is expected that an intermediate power supply product would dispatch at a 30% to 50% capacity factor depending upon the terms and dispatch price.

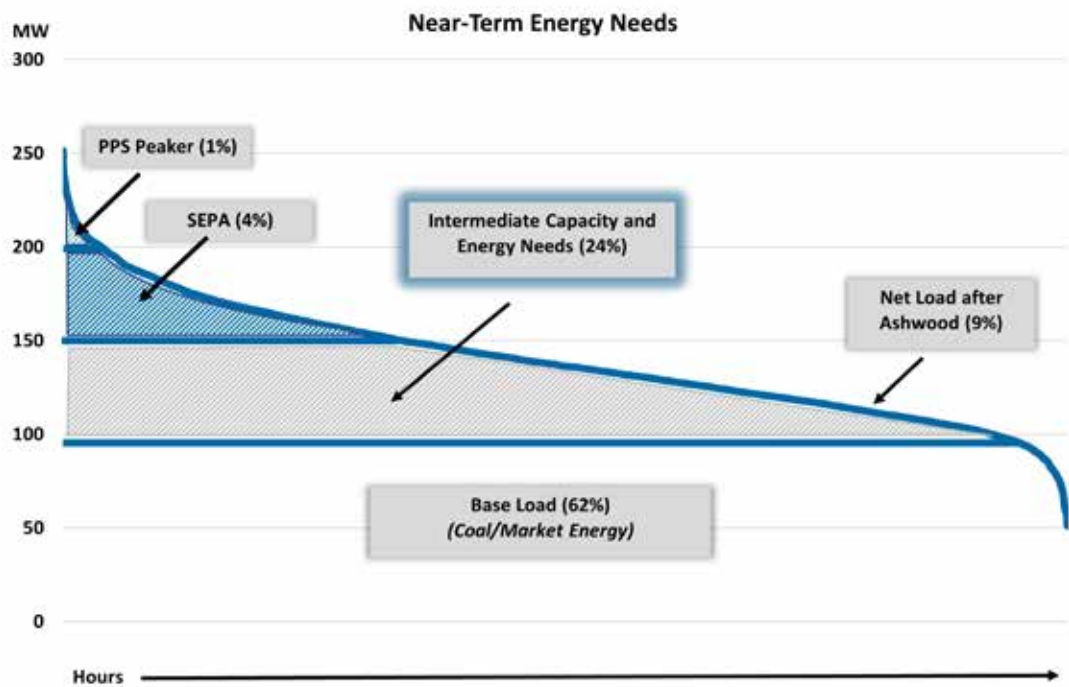


Figure 1.3-1: Near-Term Energy Needs



1.4 Selection of Supply Options

KYMEA conducted an RFP process in August 2020 to gauge market opportunities and options for KYMEA's next power supply tranche to fit the intermediate need identified by the load duration curve analysis. The RFP produced 32 proposals from 11 respondents. The proposals included ownership options and dispatchable or non-dispatchable Purchase Power Agreement (PPA) options that could be used in some fashion to provide the specified capacity and energy. Also included were proposals under which KYMEA could purchase capability and output of solar plants and battery energy storage equipment either separately or in combination.

The available power supply options so identified were analyzed using industry accepted IRP planning tools and processes. Figure 1.4-1 provides an overview of the analytical processes used to assess the options.

IRP FLOWCHART

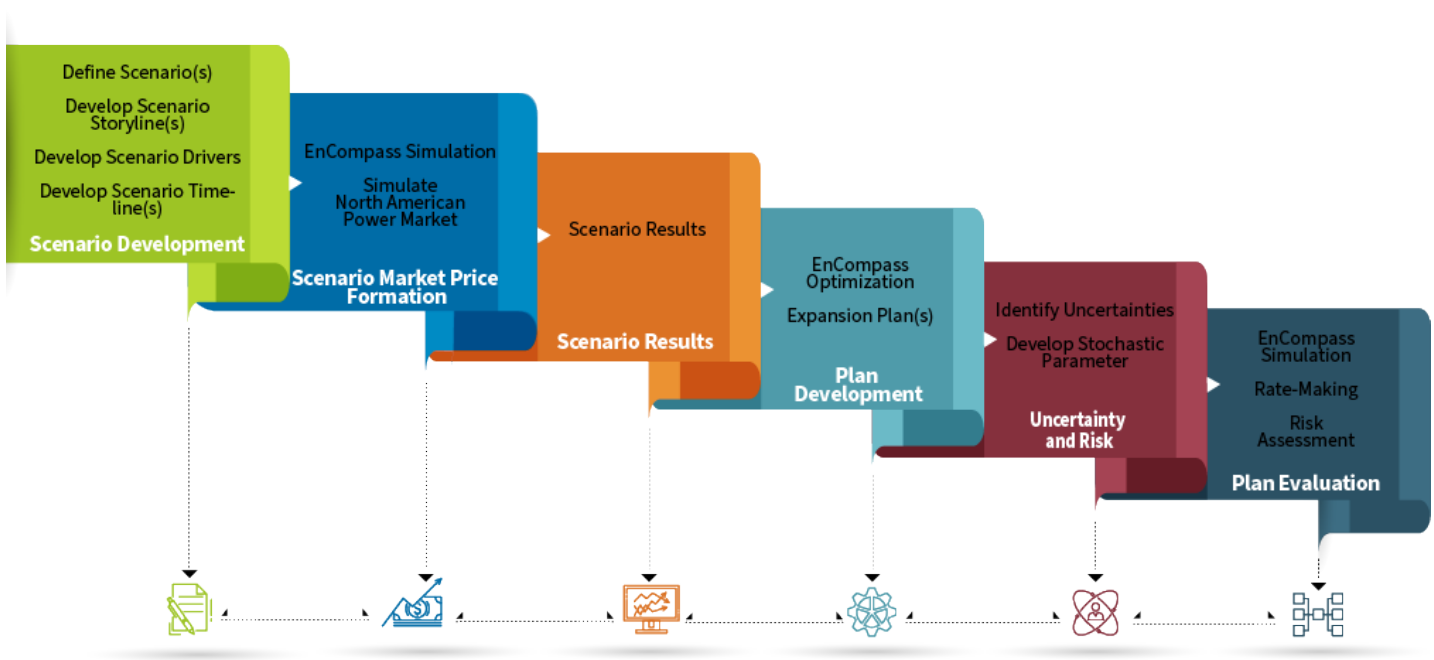


Figure 1.4-1: IRP Flowchart



1.5 Risk Assessment

Fundamentally, the analysis allowed KYMEA to assess the options in terms of projected (or mathematically expected) costs and risk that costs would be different than projected. The IRP process then identified the options that had the best mix of cost versus risk and were consistent with the Board's sense of priorities. Figure 1.5-1 provides a glimpse of the analytical processes used to assess projected cost, uncertainty, and risk.

Sensitivity and Stress Analyses were used to evaluate near-term options. Scenario Analysis was used to evaluate long-term options. The Stochastic Analysis was used to evaluate the effectiveness and cost of hedging programs for risk management purposes for near-term options.

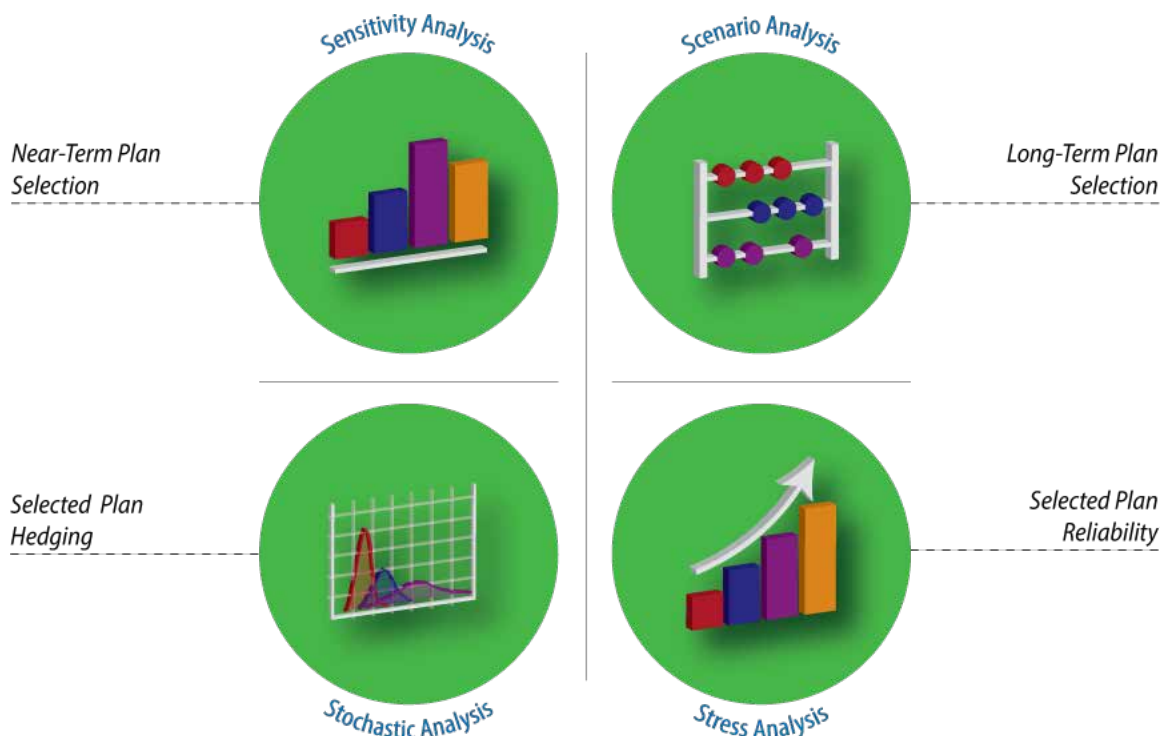
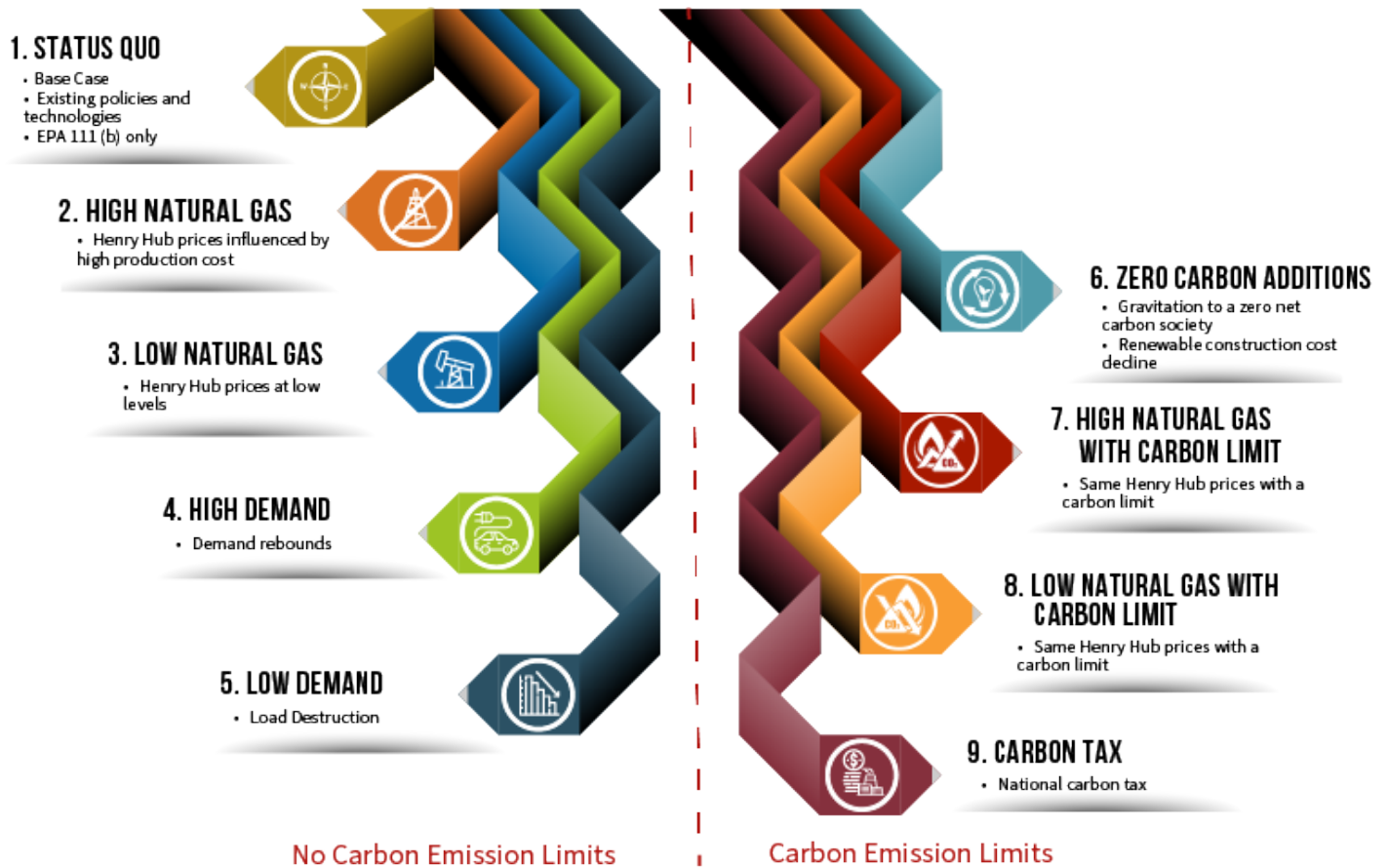


Figure 1.5-1: Risk Analysis Quadrants



Figure 1.5-2 provides an overview of the scenarios considered in development of the IRP and the related scenario analyses referred to by the Board in making power supply decisions over the past year.



KYMEA SCENARIO ROADMAP

Figure 1.5-2: KYMEA Scenario Roadmap



1.6 Preferred Plan Selection – PLAN E

On December 29, 2020, the KYMEA Board of Directors selected PLAN E, which balances projected cost and risk, and provides flexibility to adapt as circumstances change. The action items of PLAN E are as follows:

1. Reduce the PPS Peaking Capacity to 60 MW beginning June 1, 2023.
2. Negotiate a PPA for 30 MW of intermediate capacity and energy with Duke Energy-Indiana.
3. Request the necessary LKE and MISO System Impact Studies for 15 MW of MISO point-to-point (PTP) transmission and LKE network integrated transmission service (NITS).
4. Not exercise KYMEA's right of first refusal (RoFR) for an additional 32.25 MW from Ashwood.

By choosing PLAN E, the KYMEA Board chose not to exercise the Agency's right of first refusal for an additional 32.25 MW from Ashwood. If RWE, the owner of Ashwood, is unsuccessful in remarketing the additional 32.25 MW of Ashwood, then the Agency is expected to have one additional opportunity during 2021 to elect to take the additional Ashwood solar generation.

This decision not to exercise the Agency's right of first refusal was largely driven by impacts of doing so on the uncertainty regarding managing the amount of imbalance service needed from LG&E/KU. Imbalance on the grid is created when there is a difference between the total electrical supply available and the demand for electricity that exists at the same moment in time. As weather effects on solar generation make it difficult to maintain supply and demand balance within grid required parameters, KYMEA needs either additional generation online or a service from a grid operator that can provide the ability to maintain the required balance. This grid operator-provided service, MISO dynamic scheduling, is expected to be available and can mitigate the KYMEA imbalance concerns.

With the MISO dynamic scheduling service lessening KYMEA's imbalance concerns, the Agency can consider a greater Ashwood solar share should this option become available. Ashwood is scheduled to come online December 1, 2022. KYMEA's committed share is 53.75 MW. Below are the decision points and timeline of events that allows KYMEA to consider an additional 32.25 MW of Ashwood.

- OMU Ashwood Termination: OMU terminated their 32.25 MW share of Ashwood on December 10, 2020.
- KYMEA had the unilateral right of first refusal to take the additional 32.25 MW to be decided in a 30-day window. RWE (seller) notified KYMEA on January 20, 2021, creating a RoFR window of January 20, 2021, through February 19, 2021.
- The KYMEA Board chose not to exercise its RoFR, giving RWE the right to remarket the 32.25 MW.
- RWE will notify KYMEA regarding the status of the 32.25 MW remarketed portion.
- If the remarketing effort is unsuccessful, KYMEA will decide on taking the additional 32.25 MW.

If the option becomes available and KYMEA exercises the option to increase its purchases from Ashwood by an additional 32.25 MW, KYMEA would, in effect, pivot from PLAN E to a PLAN K, which would be identical to PLAN E except for the addition of 32.25 MW more from Ashwood. Under PLAN K, renewable energy would increase to approximately 19% of KYMEA's need for energy.



PLAN E versus PLAN K Comparison

When comparing the PLAN E results to the PLAN K results in Figure 1.6-1, PLAN E is lower cost in the Low Market sensitivity while PLAN K is lower cost in the Base and High Market sensitivities.

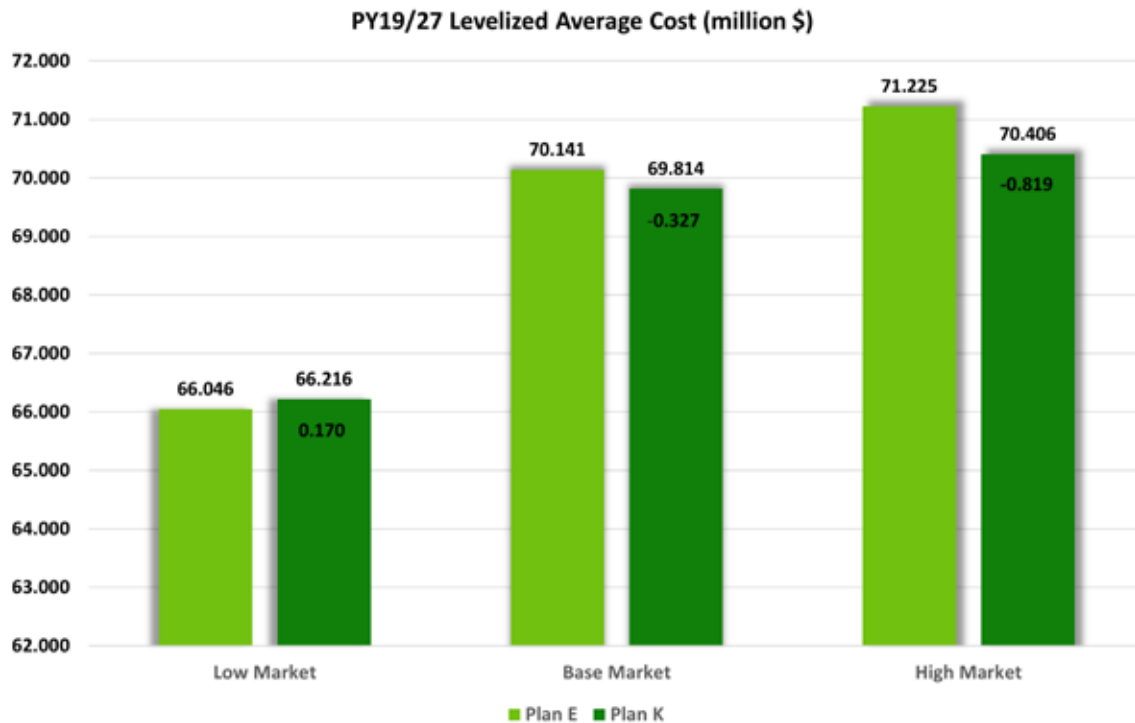


Figure 1.6-1: PLAN E and PLAN K Comparison

A decision to pivot toward PLAN K would reduce market exposure and associated risk, as compared to PLAN E. Under PLAN K, the Agency would still retain the flexibility to capture market and other opportunities because, under KYMEA's current load forecast, KYMEA would still be projected to need approximately 30 MW of additional capacity to serve its load. The plan would be to procure additional needed resources from shorter-term market transactions. The remaining flexibility would balance competing considerations of minimizing market risk, capturing economic market opportunities when available, and the Agency's reliability of supply fundamentals.

Both PLAN E and PLAN K meet fundamental utility planning criteria and Board directed priorities. More specifically, both plans:

- Provide reliable sources of generation without taking unnecessary market risk;
- Provide affordable and competitive wholesale rates with reasonable stability across the various market scenarios used to assess risk;
- Provide significant but manageable renewable resources which will reduce KYMEA's environmental footprint consistent with KYMEA's environmental stewardship priority;
- Position KYMEA to capture market opportunities and serve new members to the extent those opportunities are presented;
- Avoid long-term financial commitments beyond the near-term planning horizons, with the exception of the 32.25 MW increase in renewable resource capability purchased from Ashwood under PLAN K; and



- Offer flexibility to adapt if and to the extent demand-side and conservation options or other factors result in lower supply-side requirements.

Going Forward

Regardless of whether PLAN E remains the selected choice or PLAN K is chosen, the schedule for implementation would remain the same as shown above. The only difference in implementation steps would be the potential addition of 32.25 MW of Ashwood solar in PLAN K if KYMEA has the opportunity and decides to exercise that option.

The issuance of IRP2020 is not intended to be a stand-alone documentation of a single KYMEA plan. As flexibility is a fundamental feature of both PLANs E and K, the plan will be reassessed and adjusted as material changes occur in the market and/or in the needs of the Agency's member cities and customers. KYMEA will remain diligent in monitoring these situations and advise the Board of any recommended changes for their consideration.

It is the current intention of KYMEA to perform a comprehensive update of the IRP at three-year intervals. Should conditions warrant more or less frequent intervals, KYMEA will adjust planning processes as the KYMEA Board deems appropriate.

Closing

The rigorous detail and comprehensive analytics performed to support IRP2020 can be found in the full report.

PLAN E, or a redirection to PLAN K, is consistent with the fundamentals of prudent electric utility planning and the Board's guidance. Under both plans, KYMEA would retain the flexibility to address changes in market conditions while maintaining stable and competitive power supply costs for its members and their customers in an environmentally responsible manner.

The limited commitments to long-term resources positions KYMEA to tailor its long-term portfolio decisions to meet the Agency's objectives as more becomes known concerning federal environmental policy and related industry conditions.



As shown in Figure 1.6-2, both PLANs E and K continue to diversify the power supply portfolio being used to serve customers in the members’ communities.

Prior to the formation of KYMEA, the members purchased energy from LG&E/KU. The upper left pie chart shows the 2018 LG&E/KU resource mix, which is the last year the members purchased from LG&E/KU. The upper right pie chart illustrates KYMEA's initial portfolio resource mix for the year 2022. The bottom two pie charts illustrate KYMEA's 2025 resource mix for PLANs E and K.

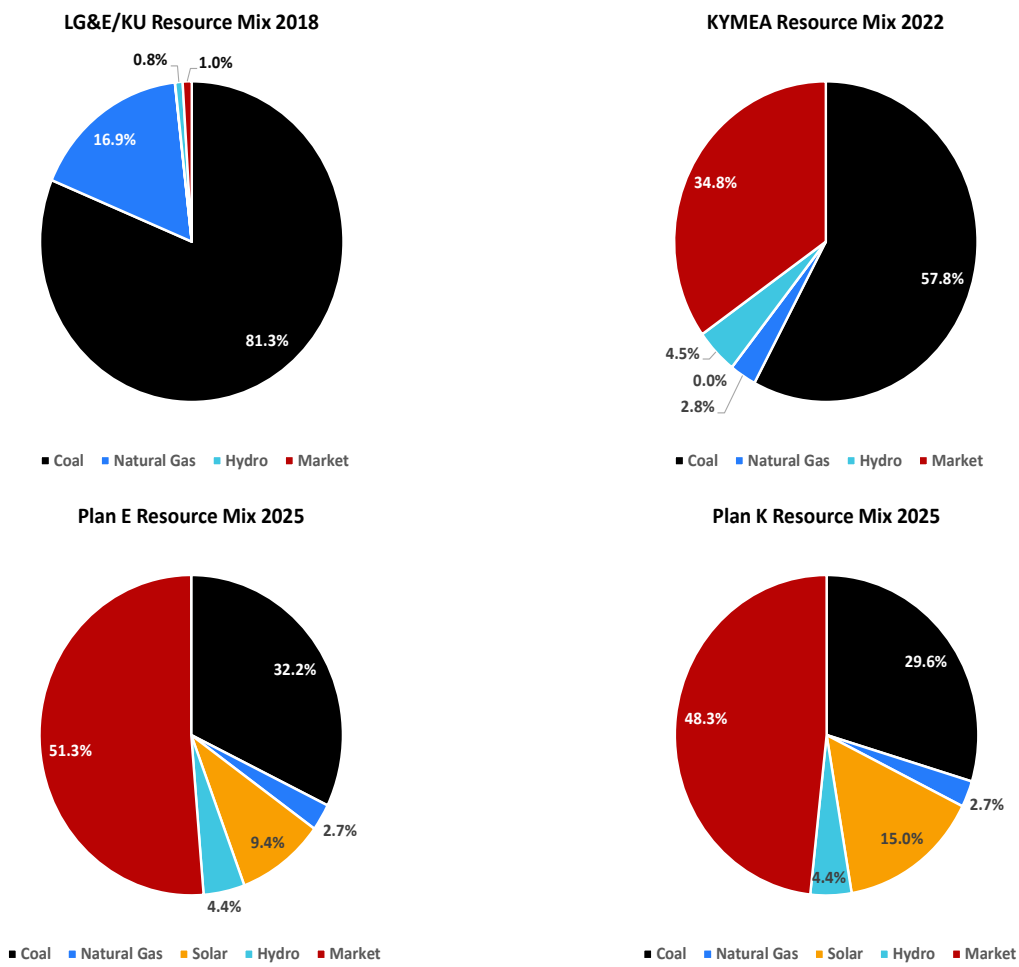


Figure 1.6-2: Mix of Energy Resources to Serve KYMEA Load



Figure 1.6-3 shows the carbon intensity projection for both PLANS E and K. Carbon intensity is calculated as pounds of carbon emitted to serve KYMEA's native load divided by the native load megawatt-hours. As points of reference, a steam-coal plant has a carbon intensity of 2,200 lb/MWh, while a natural gas combined cycle plant has a carbon intensity of 740 lb/MWh. Nuclear, hydro, solar, and wind resources do not emit carbon.

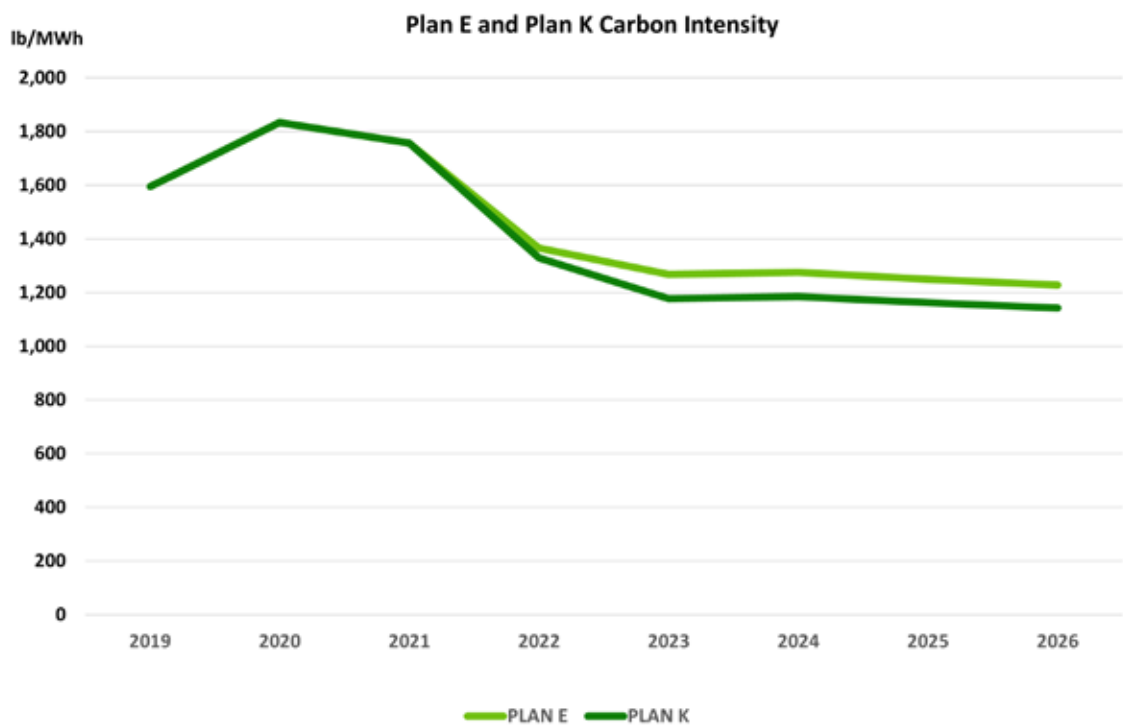
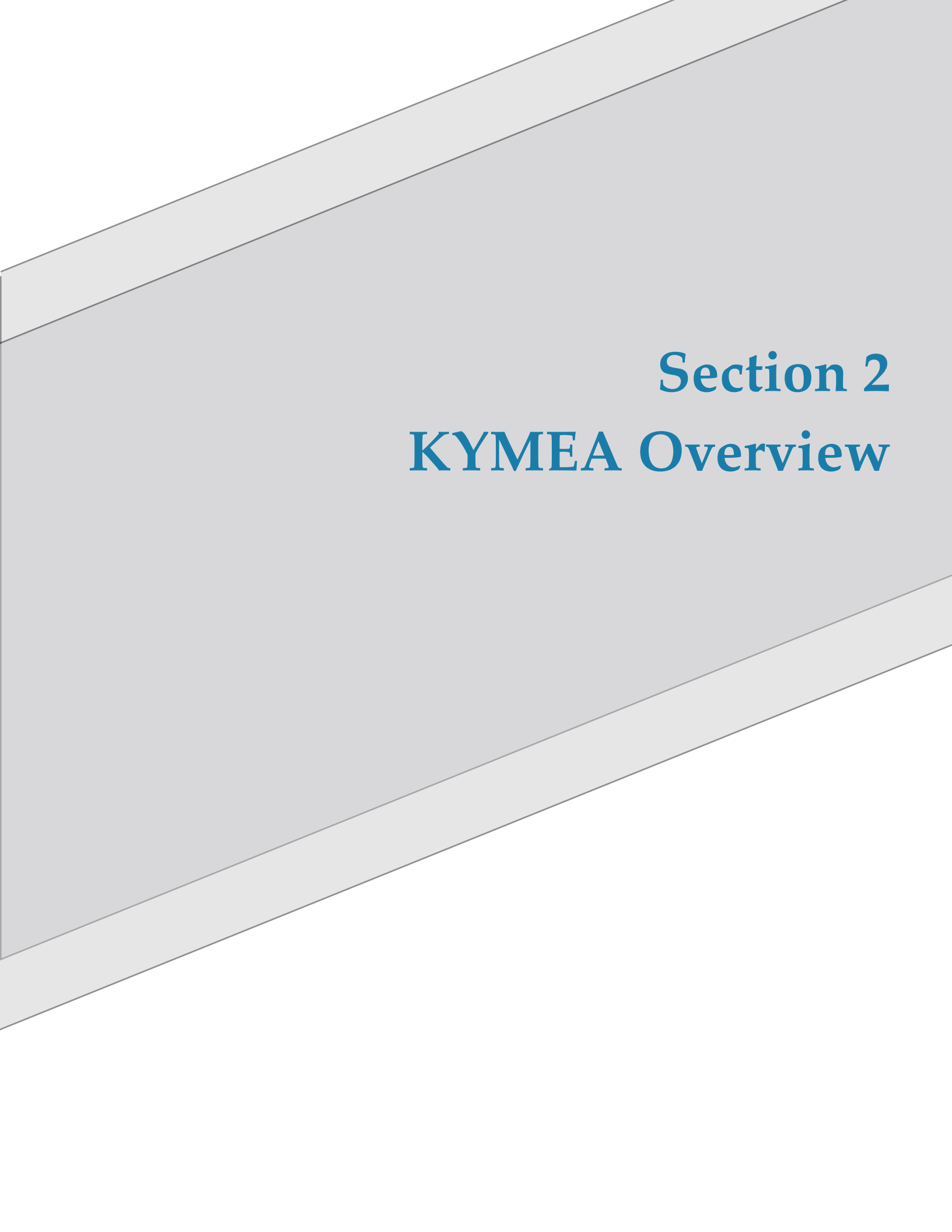


Figure 1.6-3: PLAN E and PLAN K Carbon Intensity

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Section 2

KYMEA Overview

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2. KYMEA OVERVIEW

KYMEA History

In September 2015, after 18 months of study and discussion, ten municipal electric utilities entered into an Interlocal Cooperation Agreement creating KYMEA, a joint public agency. KYMEA was formed to facilitate effective collaboration among its members to do all things necessary or convenient to serve the members' current and future electric power and energy requirements and to provide assistance to the members relating to their electric utility systems. KYMEA's Board adopted the Agency's Bylaws on September 24, 2015. On May 1, 2019, KYMEA began operations, delivering wholesale electric service to the eight all requirements members.

Timeline of KYMEA Milestones

2015	September 2015: The Cities of Bardwell, Falmouth, Madisonville, Paris, and Providence, the Frankfort Plant Board, the Barbourville Utility Commission, the Benham Power Board, the Corbin City Utilities Commission, and Owensboro Municipal Utilities enter into an Interlocal Cooperation Agreement forming KYMEA. The Agency's Bylaws are adopted on September 24, 2015.
2016	July - August 2016: Eight members (Barbourville, Bardwell, Corbin, Falmouth, Madisonville, Paris, Providence, and the Frankfort Plant Board) enter into All Requirements Power Sales Contracts with KYMEA. The Agency completes the assembly of an initial portfolio of resources consisting of purchase power agreements with Big Rivers Electric Corporation, Illinois Power Marketing Company, and Paducah Power System. September 2016: The City of Berea (Berea) asks to join KYMEA and the Interlocal Cooperation Agreement is amended to add Berea as its eleventh member. Berea enters into a Transmission Service Agreement with KYMEA.
2017	May 2017: Deliveries of electricity to the Benham Power Board and the City of Paris begin using transmission service procured on their behalf by KYMEA. December 2017 - April 2018: The City of Paris and KYMEA agree to enter into an agreement to utilize the Paris diesel generation as part of the Agency's AR Project power supply portfolio. The all requirements members enter into agreements for KYMEA to use their entitlements to hydroelectric power from the Southeastern Power Administration (SEPA) as part of the AR Project power supply portfolio.
2018	January 2018: KYMEA hires its first president and CEO. August 2018: The Agency executes a 20-year agreement with MAP® Energy and Open Road Renewables for 62.5% of the output of the 86MW Ashwood Solar I power plant as part of the Agency's AR Project power supply portfolio. The plant is scheduled to go into service in late 2022. November 2018: The Agency opens permanent offices in Louisville, Kentucky.
2019	May 2019: At the stroke of midnight on May 1, a new electric power era began for eight communities that are members of the Kentucky Municipal Energy Agency (KYMEA). After decades of purchasing electricity from Kentucky Utilities Company, the Frankfort Plant Board and the municipal electric utilities of Barbourville, Bardwell, Corbin, Falmouth, Madisonville, Paris, and Providence are now being served by KYMEA, the joint public agency they created to obtain lower-cost, reliable electricity for their communities.



KYMEA Member Services

KYMEA provides wholesale power and energy services to eleven municipal electric systems throughout the Commonwealth of Kentucky. Current KYMEA members are Barbourville Utility Commission, Bardwell City Utilities, Benham Plant Board, City of Berea Municipal Utilities, City Utility Commission of Corbin, City of Falmouth, Frankfort Plant Board, Madisonville Electric Department, Owensboro Municipal Utilities, City of Paris Combined Utilities, and the City of Providence Utilities. The Agency is not bound within the Commonwealth of Kentucky and may serve municipal electric systems outside its borders.

KYMEA exists to serve its members. Members may choose to enter into contracts with KYMEA for power supply or other services. Members also have the flexibility to establish projects for the benefit of one or more members, such as the All Requirements Project (AR Project), which has been created to acquire power supply resources to serve the needs of eight participating All Requirements (AR) members. The business model objective of KYMEA is to provide cost-effective resources and services for the benefit of its members to enable them to achieve objectives they have set for themselves more efficiently and at lower costs than they could achieve individually.

KYMEA is in its third year of operations. To create its initial portfolio, KYMEA worked through numerous resource planning and modeling processes that were essentially the activities of an IRP. The IRP2020 is KYMEA's first formal IRP that includes a published report.



Figure 2-1: Eleven KYMEA Members



2.1 KYMEA’s Vision, Mission, and Values

The Agency established its vision, mission, and values to enable stakeholders to understand the Agency’s destination and the means by which it will reach that destination. KYMEA is a not-for-profit agency and receives no tax money. The Agency sets rates as low as possible to achieve its mission of providing reliable, affordable, and sustainable energy services to the communities we serve. KYMEA is a public power agency and is not regulated by the Kentucky Public Service Commission (PSC). KYMEA will perform its due diligence in developing a prudent plan to provide recommendations and an action plan to address wise utility practices, industry changes from technological advancements, member preferences, regulatory mandates, and market trends. It is imperative to keep in mind the vision, mission, and values that the leaders have established provide a road map and culture that will help to guide corporate decisions moving forward.

Vision



We shall positively impact our communities as a trusted leader of power supply and energy-related services.

Mission



Through collaboration and operational excellence, we provide reliable, affordable, and sustainable energy services to the communities we serve.



KYMEA Values

The following values help to further define KYMEA's devotion to supporting the vision and mission that will move the Agency forward as a collaborative team working toward a common goal.



Integrity

To conduct business in an honest, transparent, just, compliant, and environmentally responsible manner by holding ourselves to high ethical and accountability standards.



Respect

Encouraging constructive dialogue that promotes a culture of inclusiveness, and recognizes our differences while valuing the perspective, talents, and experiences of others.



Fiscal Responsibility

An obligation to be accountable to the fiscal policies of the Agency with budgetary discipline and affordable rates while practicing long-term planning and prudent use of debt.



Member Focused

We are committed to listening and responding positively to our members and their customers.



Operational Excellence

We seek to achieve and maintain the highest level of excellence by performing in a productive and proficient manner, and adhering to best practices while providing a quality workforce.



2.2 IRP2020 Participants

KYMEA's eight AR Project members - Barbourville, Bardwell, Corbin, Falmouth, Frankfort, Madisonville, Paris, and Providence - and the two transmission-only members (TO members) of Berea and Benham participated in the IRP2020.

The AR Project's next tranche of power-supply needs occurs in 2022, while the TO members' power-supply needs occur in 2024. The combined power-supply need, over and above the PPAs already in place, is approximately 130 MW of capacity and 500,000 MWh of energy.

Table 2.2-1 lists the 10 participant's demographics.

Table 2.2-1: IRP2020 Participant Demographics

Member	Residential Customers	Commerical and Industrial	Total Customers	Began Electric Service	Years of Service
Barbourville Utility Commission	3,415	688	4,103	1938	81
Bardwell City Commission	401	93	494	1944	75
Benham Power Board	277	6	283	1961	58
Berea Utilities	4,644	645	5,289	1917	102
City Utilities Commission of Corbin	3,416	719	4,135	1915	104
City of Falmouth	870	165	1,035	1963	56
Frankfort Plant Board	16,492	4,233	21,793	1946	73
Madisonville Electric Department	6,808	1,634	8,442	1922	97
City of Paris Combined Utilities	2,500	538	3,038	1933	86
City of Providence Utilities	1,191	144	1,335	1924	95
Total	40,014	8,865	49,947		

* As of 2020

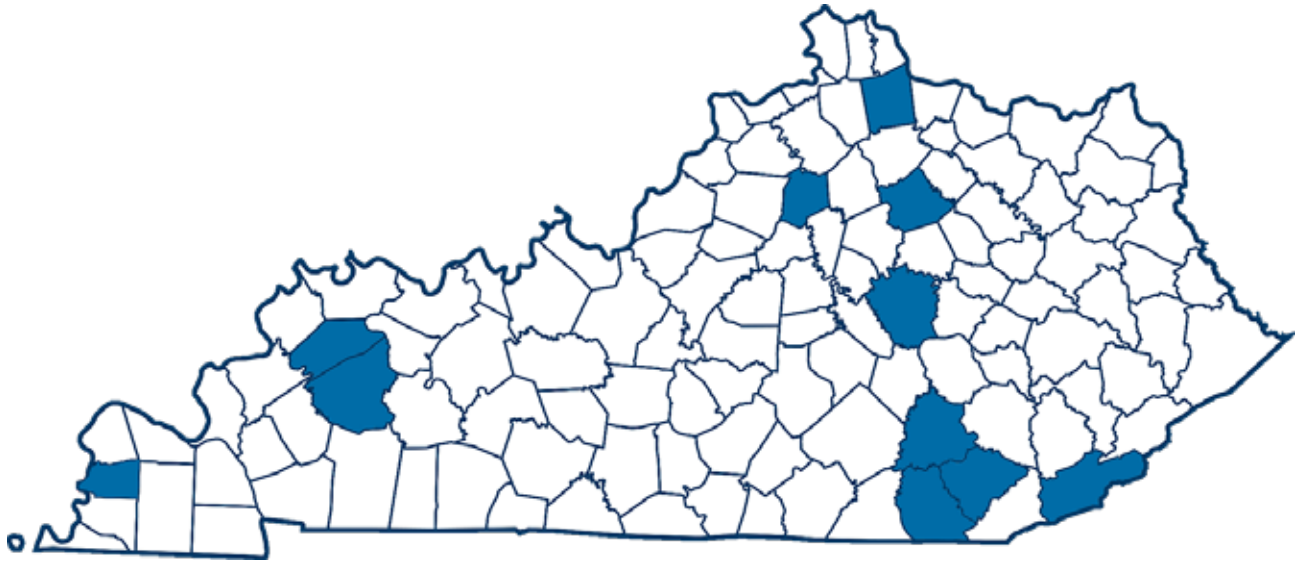


Figure 2.2-1: IRP2020 Participant Counties



BARBOURVILLE

Barbourville Utilities
Population: 3,165



FALMOUTH

City of Falmouth Utilities
Population: 2,139



BARDWELL

Bardwell City Utilities
Population: 723



FRANKFORT

Frankfort Plant Board
Population: 25,527



BENHAM

Benham Power Board
Population: 500



MADISONVILLE

City of Madisonville, Electric Department
Population: 19,591



BEREA

City of Berea Municipal Utilities
Population: 15,844



PARIS

City of Paris Combined Utilities
Population: 8,553



CORBIN

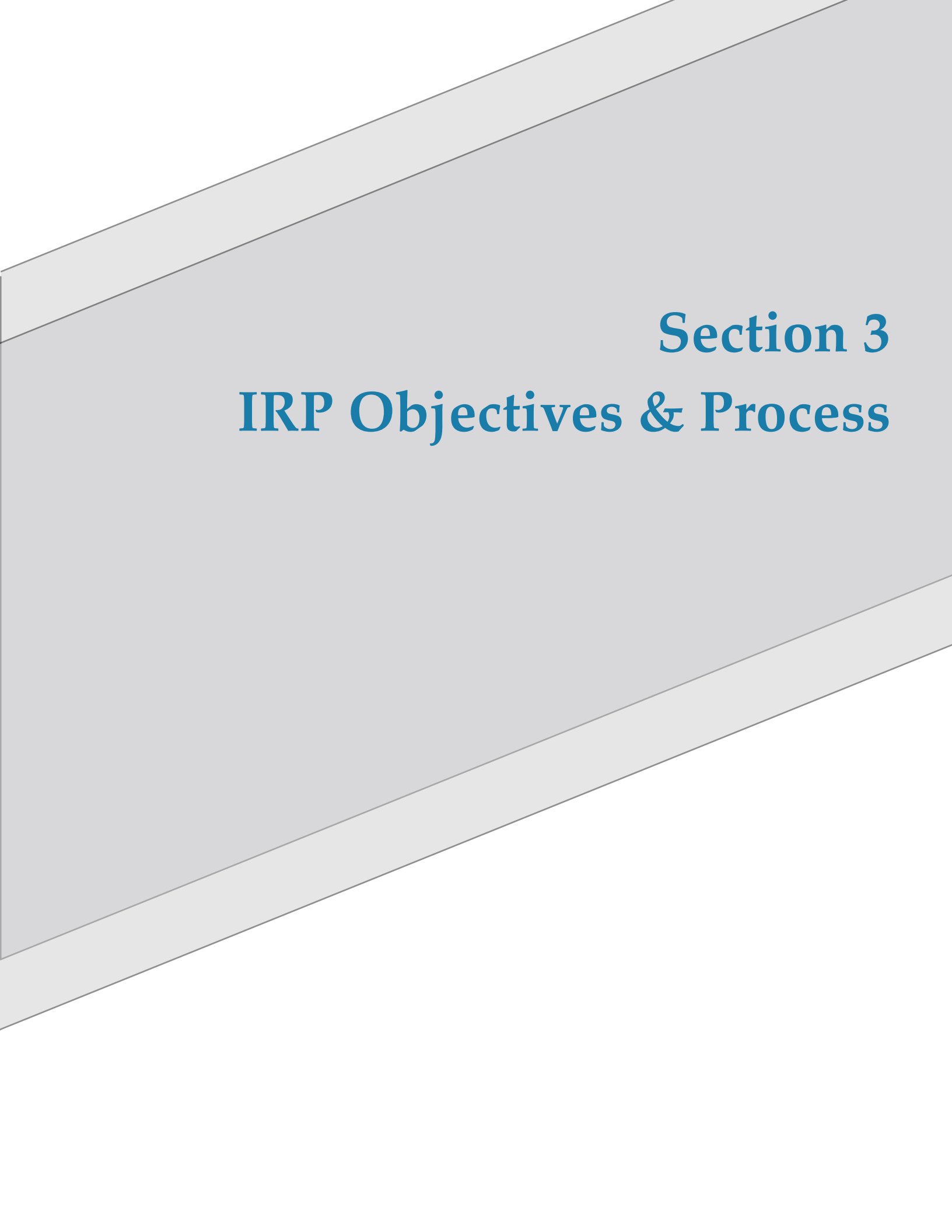
City Utilities of Corbin
Population: 7,304



PROVIDENCE

City of Providence Utility Office
Population: 2,981

* 2020 Census



Section 3

IRP Objectives & Process

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3. IRP OBJECTIVES AND PROCESS

KYMEA is committed to the vision and mission laid out in its 2019 Strategic Plan.

The IRP2020 is a long-term integrated resource plan that provides a 20-year blueprint on how KYMEA can best succeed in upholding the strategic vision of positively impacting our communities as a trusted leader of power supply and energy-related services and the strategic mission of utilizing collaboration and operational excellence to provide reliable, affordable, and sustainable energy services to the communities we serve while meeting the future demand for energy from its members. The plan is a crucial element for KYMEA's success in a continually changing industry and regulatory environment. It will best position KYMEA to meet many of the challenges facing the power sector in the coming years.

KYMEA utilized an integrated, least-regrets framework that considered multiple scenarios based on a range of plausible futures to determine how potential power generation resource portfolios could perform in different markets and external conditions. The IRP process was conducted in a transparent, inclusive manner that provided numerous opportunities for public education and participation. Stakeholders and the public provided valuable input that helped shape the IRP. The analysis performed in this IRP study relied on industry-standard models and incorporated best practices while using an innovative methodology. Resource cost and performance input data were independently validated. KYMEA's goal with IRP2020 was to identify an optimal energy portfolio that performs well under a variety of different future conditions, taking into consideration cost, risk, environmental stewardship, operational flexibility, and economics.

IRP Objectives and Metrics



Figure 3-1: IRP Objectives and Metrics

2
0
2
0

IRP2020 Timeline

MARCH/APRIL

Development of Model Input and Framework: Identify and develop scenarios, resource options and business strategies to evaluate how a future portfolio might change under different conditions.

MAY/JUNE

Community IRP Focus Group: Identify issues important to the public and lay the foundation for developing the IRP.

JULY/AUGUST

Analysis and evaluation: Develop and evaluate the performance of multiple resource portfolios.

Focus Group Feedback Period: Compile feedback from public participants.

SEPTEMBER/OCTOBER

Additional Analysis: Response to focus group feedback.

Preliminary results of the study: IRP recommendation, near-term actions and key elements, and the final environmental assessment.

NOVEMBER/DECEMBER

Board of Directors Action: Approval of near-term IRP recommendations

Publication of the IRP2020 - July 2021



Public Participation

KYMEA made it a priority to understand the various concepts and needs of its members and their customers. COVID-19 created a challenge to this objective. Through collaboration and public participation via video meetings, the Agency was able to consider the public's ideas and facilitate effective dialogue between KYMEA and the citizens of our member communities.

KYMEA's public participation goals were:

- To engage participation in the Agency's first formal IRP.
- To provide educational opportunities to the public, who, prior to KYMEA's formation, did not have an opportunity to participate in an IRP process.
- To foster open communication and transparency throughout the IRP process.
- To incorporate public feedback into the IRP process through community focus group sessions and website feedback forms.

KYMEA hosted two Community Focus Group Sessions.

- June 24, 2020, 10 AM – 3 PM, Live WebEx Video Meeting
- September 2, 2020, 10 AM – 3 PM, Live WebEx Video Meeting

The Community Focus Group sessions were open to the public. The sessions were advertised on the Agency's website at KYMEA.org. The session details were featured at the KYMEA Board meetings and in web and news outlets. To ensure public safety and compliance with the Centers for Disease Control and Prevention (CDC) guidelines in response to the pandemic, KYMEA made virtual participation available to its members and the public via live WebEx video meetings.

IRP2020 Community Focus Group Sessions

June 24, 2020, Community Focus Group

The June 24, 2020, Community Focus Group session provided attendees an overview of the KYMEA portfolio, the IRP process and timeline, and an opportunity for live questions and answers. Speakers included the KYMEA team and industry experts from Boyd CAT and RWE Renewables Americas, LLC. The team allocated time to answer all questions asked in both the morning and afternoon Q&A sessions. Speakers fielded various questions regarding load growth, environmental stewardship, resource supply, and transparency. Participants were encouraged to review the list of the questions and answers that were subsequently published on the KYMEA website at <https://www.kymea.org/irp/irp-resources/>. Twenty-three people attended the meeting in person or via WebEx.

September 2, 2020, Community Focus Group

During the September 2, 2020, Community Focus Group Session, staff primarily focused on scenario modeling and presenting preliminary results. The team allocated time to answer all questions that were asked during both the morning and afternoon Q&A sessions. Thirty-one people attended the meeting in person or via WebEx.

All session videos, presentation materials, and public feedback were made available at <https://www.kymea.org/irp/irp-resources/>.



Least-Cost Planning

IRPs utilize least-cost planning to determine suitable resource mixes. The least-cost model selects the most inexpensive portfolio of available resources to satisfy procurement needs.

As shown in Figure 3-2, the load forecast provides the need for the new resources. The selected portfolio considers social environmental factors and uncertainty analysis through model simulations to arrive at a least-cost plan.

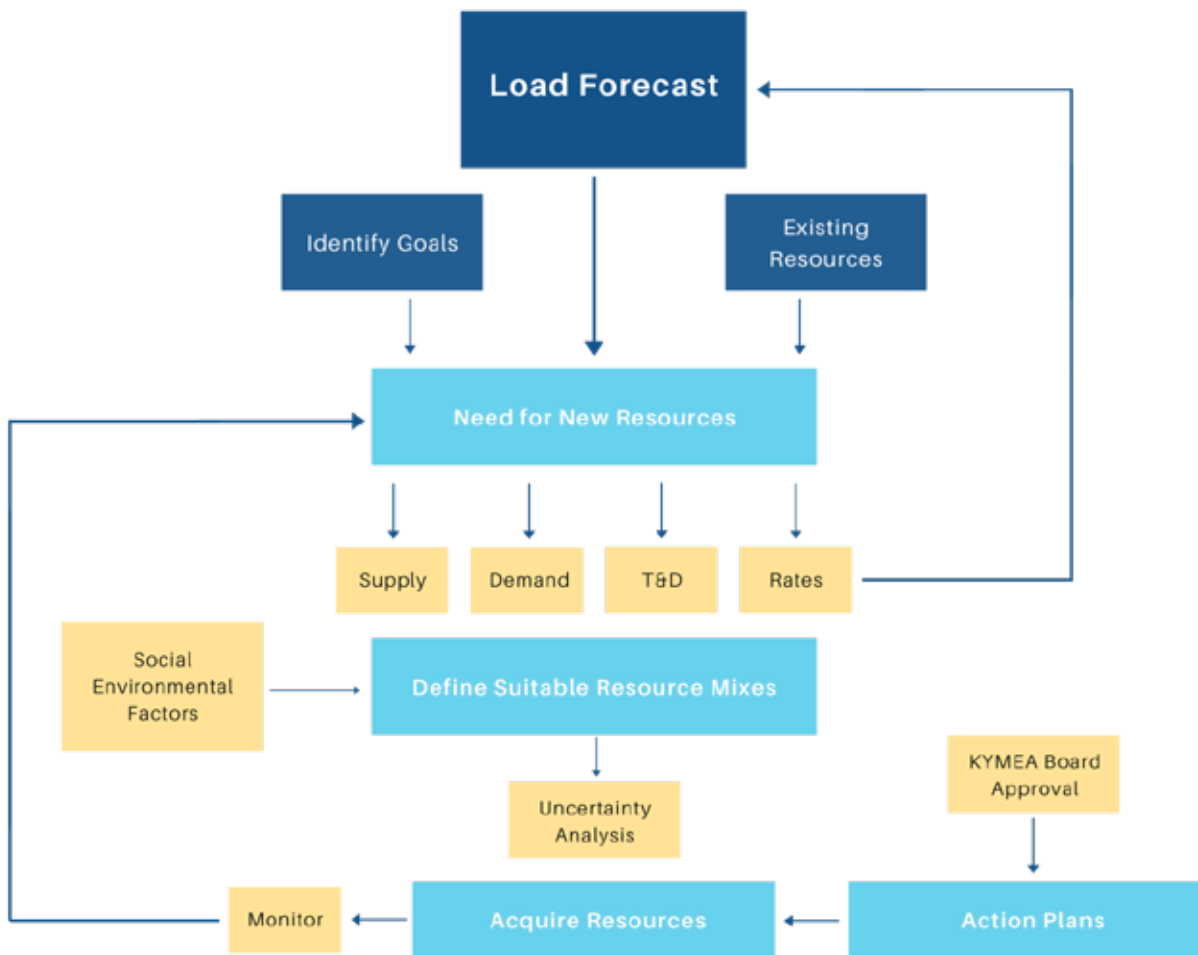


Figure 3-2: Least-Cost Planning Flowchart



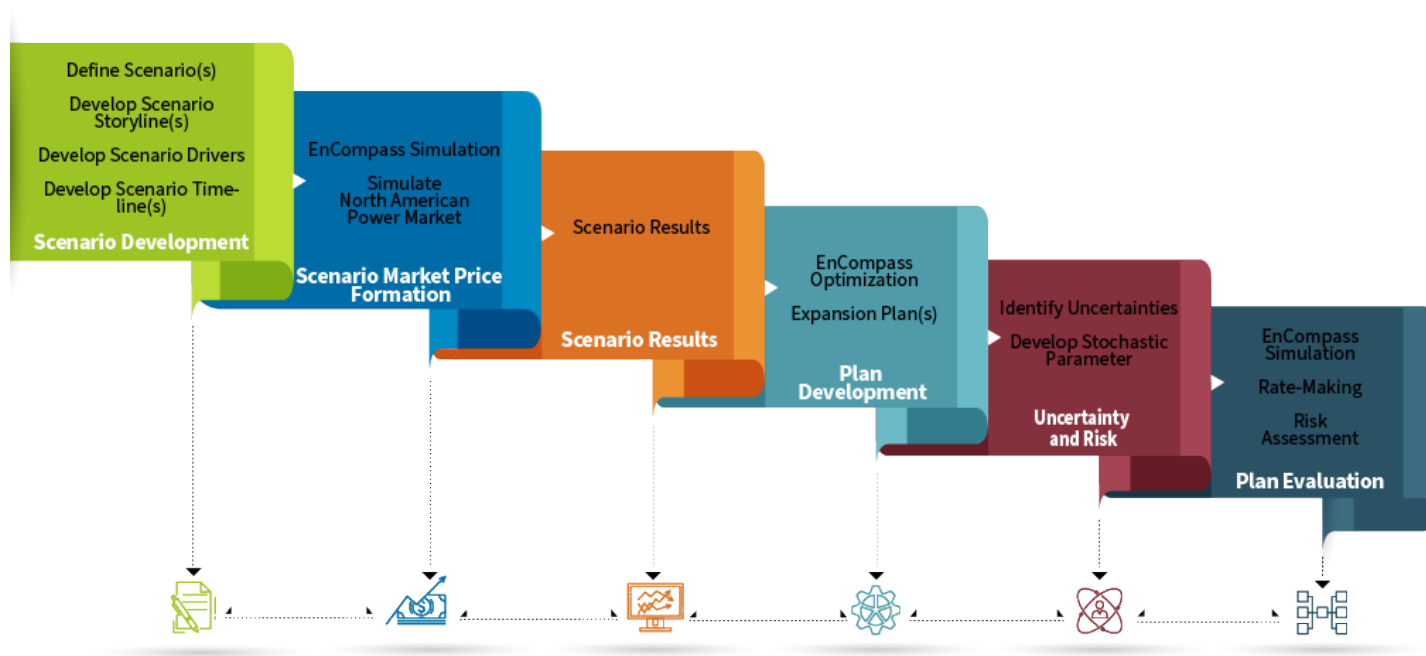
Least-Regrets Scenario Planning

The selection of the least-cost plan may force the planner to make a single assumption or prediction about future conditions and outcomes which are most likely to occur. As levelized cost calculations necessarily include projections of uncertain future costs, such as power and fuel costs or environmental compliance costs, levelized cost projections should account for risk and uncertainty or even paradigm shifts in the industry. A portfolio can have low levelized costs under some future scenarios, but very high costs under others. Consequently, a preferred least-cost portfolio may not be resilient to changing circumstances.

KYMEA's progressive approach to the IRP process utilizes least-regrets scenario planning which requires selecting scenarios based upon reasonable possible future circumstances and events rather than cost alone. The selected preferred plan is low cost, flexible, and robust.

This least-regrets methodology considers the impact of key business unknowns such as load growth, new technologies, fuel prices, and environmental policies. Each key unknown is forecasted as a plausible future scenario, and candidate plans are developed for each scenario. The output of KYMEA's process is a portfolio that will perform well and provide success under numerous unique and challenging possible futures. The scenario planning process is shown in the IRP Flowchart below.

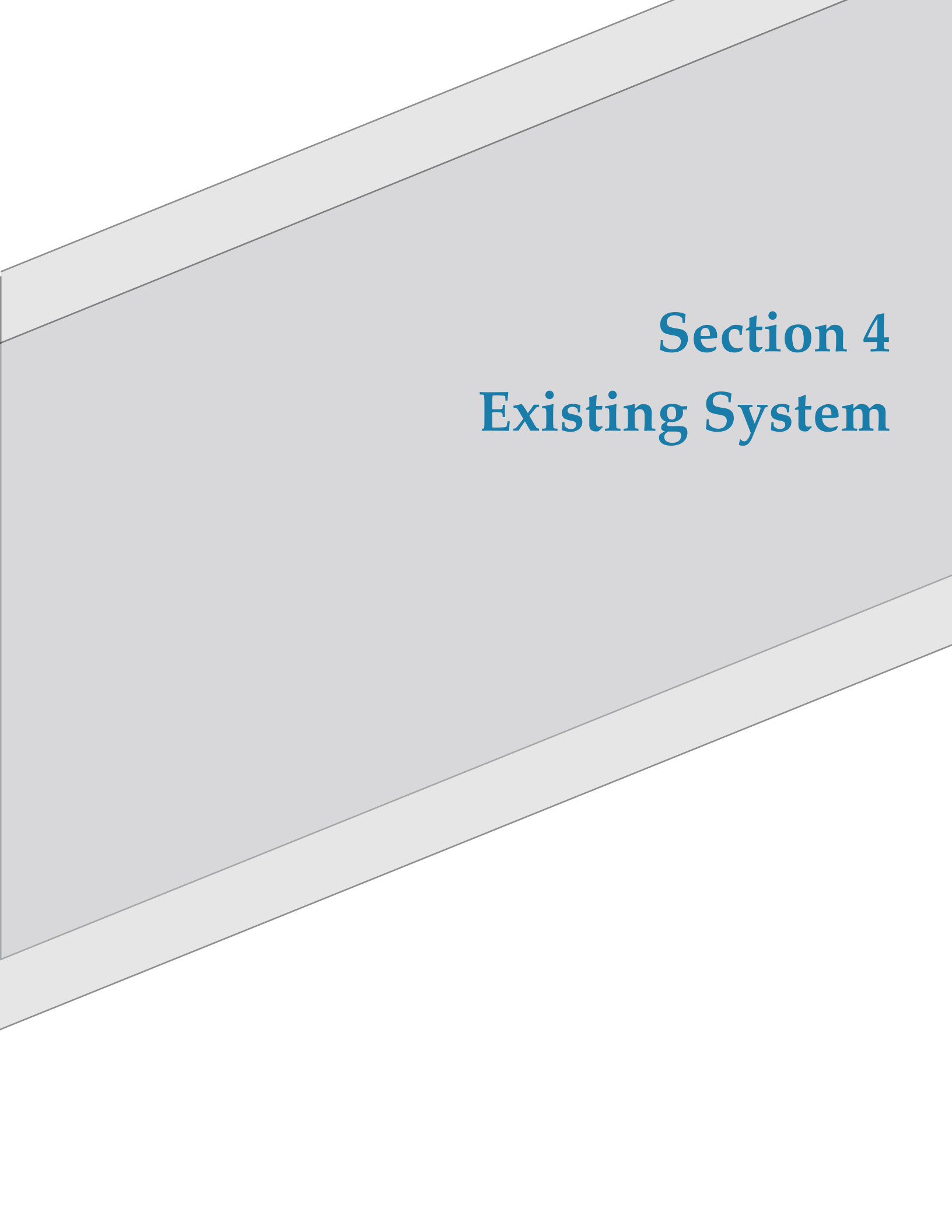
IRP FLOWCHART



In its short history, KYMEA has safely and reliably met member needs, engaged in the economic and social development of member communities, and solidified its planning efforts to accommodate the next phase of energy growth and development in the areas it serves - all while significantly lowering costs.

The least-regrets integrated resource plan process represents the best-suited platform to aggregate today's challenges with tomorrow's opportunities, ensure comprehensive planning efforts, and pursue community engagement. To guide the creation and implementation of these strategic directions, the IRP2020 is founded on the three core strategic mission principles of reliability, affordability, and sustainability, as well as the additional principles of flexibility and risk management.

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Section 4

Existing System

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4. EXISTING SYSTEM

4.1 KYMEA System Description

KYMEA provides all-requirements energy delivery services to 8 municipal electric systems located in the Commonwealth of Kentucky. Seven of the members – Barbourville, Bardwell, Corbin, Frankfort, Madisonville, Paris, and Providence - reside within the LG&E/KU Balancing Authority (BA); and one member, Falmouth is located inside PJM. KYMEA also provides transmission services to two members – Berea and Benham - that also reside within the LG&E/KU BA.

Figure 4.1-1 shows LG&E/KU (labeled as LGEE) and surrounding BAs. LG&E/KU has direct interfaces to MISO, PJM, TVA and EEI; however, EEI will become a member of MISO on June 1, 2022, reducing the direct interface points with LG&E/KU to three.⁴

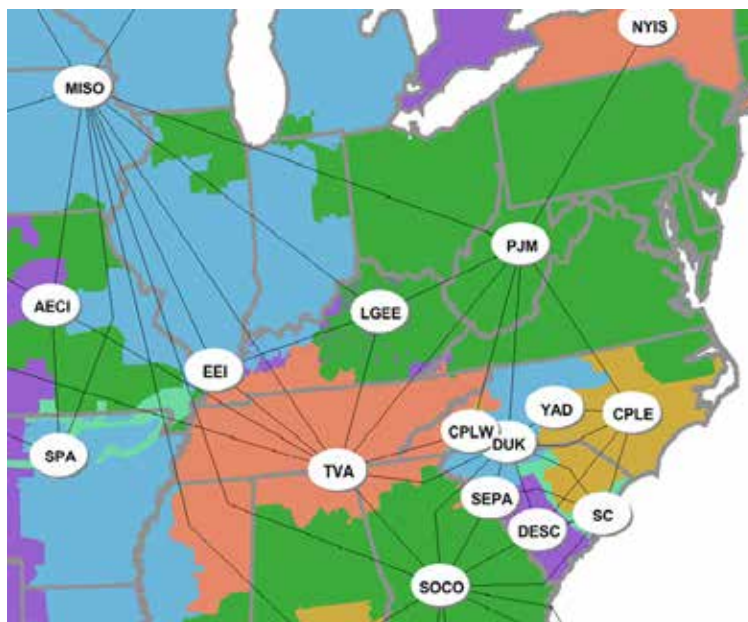


Figure 4.1-1: LG&E/KU and Surrounding Balancing Authorities⁵

⁴ Gridliance to acquire transmission assets from Electric Energy, Inc. <https://www.gridliance.com/gridliance-to-acquire-transmission-assets-from-electric-energy-inc/>

⁵ NERC. (2019, October). Balancing Authority Areas [Digital image]. Retrieved May 04, 2021, from <https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx>



The TVA Fence

As previously described, beginning in June 2022, LG&E/KU has direct access to three markets – MISO, PJM, and TVA. While KYMEA is in the LG&E/KU BA, the Agency only has access to two markets – MISO and PJM. Except for the KYMEA members' Southeastern Power Administration (SEPA) hydroelectric power entitlement, neither KYMEA nor its members, can purchase power from TVA due to "The TVA Fence." Opportunities may exist where KYMEA could purchase energy at the TVA interface from enabled counterparties, although this would require incremental transmission costs embedded in the offer price or as a separate purchase of TVA transmission.

The TVA Fence History: In 1959, an amendment was added to the TVA Act, which created a "Fence" around TVA. The Fence prohibits TVA from selling power to any municipality which received service from another source on or after July 1, 1957. As such, KYMEA and its members cannot purchase from TVA.

Figure 4.1-2 highlights the TVA Fence.

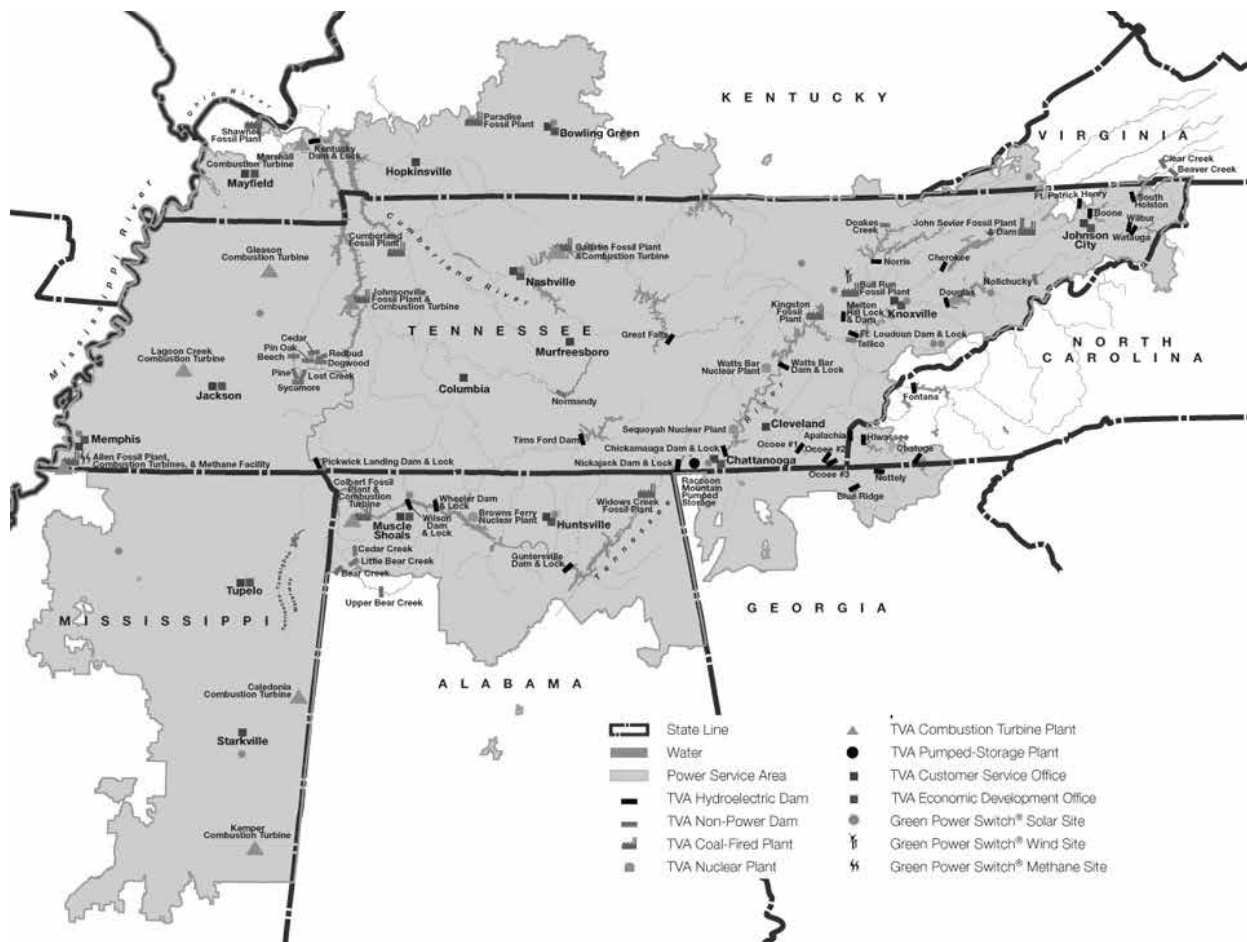


Figure 4.1-2: The TVA Fence Map⁶

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION Annual Report Form 10-K. (2007, December 12). Retrieved from <https://www.sec.gov/Archives/edgar/>

data/1376986/000137698607000014/tva10-k.htm



Transactions with LG&E/KU are Limited to Cost-Based Rates

KYMEA cannot purchase power at market-based rates from LG&E/KU. LG&E/KU has horizontal market power within the LKE transmission system. KYMEA can only purchase cost-based power from LG&E/KU.

Multiple Balancing Authority Areas in Kentucky

The Commonwealth of Kentucky has four BA areas illustrated in Figure 4.1-3. A BA is the responsible entity that maintains load-interchange-generation balance within a BA area and supports interconnection frequency in real time. A BA area is the collection of generation, transmission, and loads within its metered boundaries where it is required to maintain load-resource balance.

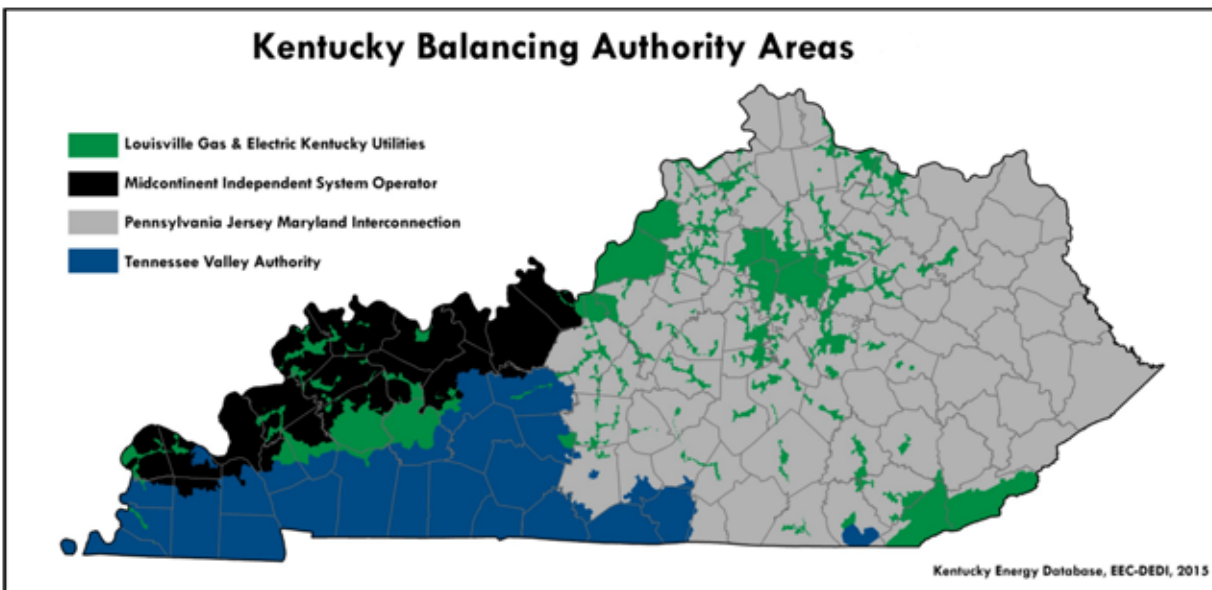


Figure 4.1-3: Kentucky Balancing Authority Map⁷

⁷ Kentucky Energy Profile (7th ed., Rep.). (2019). Kentucky Energy and Environment Cabinet Office of Energy Policy. doi:<https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202019.pdf>



4.2 Loads and Load Growth

KYMEA's members have a mixture of commercial, industrial, and residential loads. Based upon the most recent forecast for KYMEA's compliance with NERC MOD-032, KYMEA anticipates annual growth in energy, and non-coincident peaks to be less than one-half percent, over the next ten years. Table 4.2-1 shows last fiscal year's energy and peak summary. A detailed description of the load forecast will be discussed in Section 5 of this report.

Table 4.2-1: KYMEA FY 2019/2020 Load and Peak Summary

Member	FY 2019/2020 Peak (MW)	FY 2019/2020 Energy (MWh)
City of Bardwell	2.06	9,308
City of Berea	27.00	136,610
City of Falmouth	4.54	20,634
City of Madisonville	60.06	303,947
City of Paris	13.78	64,895
City of Providence	6.26	29,053
Frankfort Plant Board	136.09	712,322
Barbourville Utility Commission	19.03	93,090
Benham Power Board	2.19	6,366
Corbin City Utilities Commission	19.04	88,454
AR Members	260.86	1,321,703
Non-AR Members	29.19	142,976
KYMEA	290.05	1,464,679

Note: IRP2020 participants only. Table 4.2-1 excludes Owensboro Municipal Utilities.



4.3 AR Project Initial Resource Portfolio

The electricity supplied to KYMEA's AR Project members comes from a variety of power sources including solar, natural gas, coal, and hydroelectric. KYMEA pulled together its initial set of power supply resources to meet the AR Project's needs at significant wholesale power cost savings from the cost of its previous power supply arrangement.

Figure 4.3-1 and Table 4.3-1 illustrates the location and details of KYMEA's existing resources.

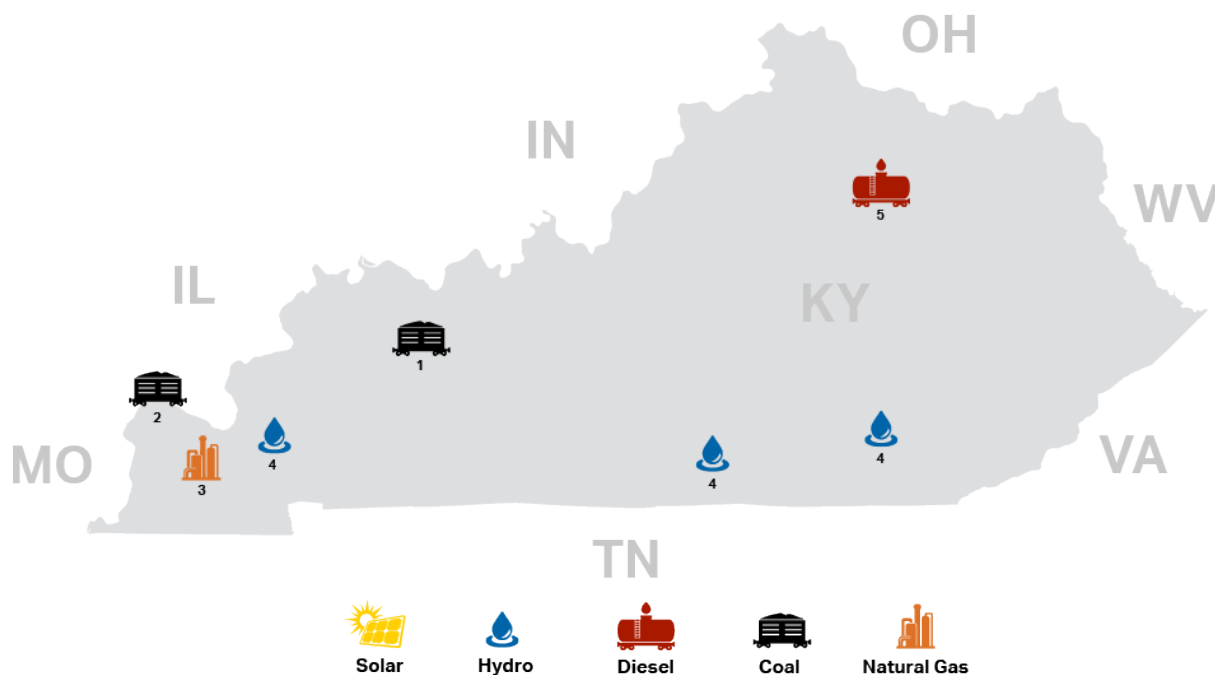


Figure 4.3-1: KYMEA Resource Map

Table 4.3-1: KYMEA Resource Details

Map ID	Resource	Fuel	Type	Capacity (MW)	Term End
1	BREC D.B. Wilson	Coal	PPA	100	May 31, 2029
2	IPMC Joppa	Coal	PPA	100	May 31, 2022
3	PPS Plant 1	Natural Gas	PPA	90	May 31, 2029
4	SEPA	Hydro	Member	32	
5	Paris	Diesel	PPA	11	May 31, 2029



Existing Coal

Big Rivers Electric Corporation D.B. Wilson PPA - 100 MW

Big Rivers Electric Corporation (BREC) and KYMEA entered into a ten-year power supply contract for firm capacity and energy. The contract entitles KYMEA to 100 MW of base capacity, plus associated planning reserves, sourced from the Big Rivers generating fleet. Service under the contract commenced on May 1, 2019. BREC's D.B. Wilson power plant, located in western Kentucky, is a single-unit, 417 MW sub-critical coal-fired steam power plant. The plant reached commercial operation in September 1984.

Illinois Power Marketing Company Joppa PPA - 100 MW

Illinois Power Marketing Company (IPMC) and KYMEA entered into a three-year power supply contract for 100 MW of capacity and energy from three units of the Joppa Power Station. Joppa Power Station, located in southern Illinois, is a 1,002 MW sub-critical coal-fired power plant consisting of six generating units. The first unit reached commercial operation in August 1953, and the newest unit reached commercial operation in August 1955. Service under the contract commenced on June 1, 2019.

Existing Natural Gas

Paducah Power System PPA – 90 MW

Paducah Power System (PPS) and KYMEA entered into a ten-year power supply contract for 90 MW of capacity and energy from the PPS Power Plant No 1. KYMEA has a one-time option to reduce the capacity to as low as 30 MW beginning June 1, 2023. PPS Power Plant No 1, located in western Kentucky, is a 124 MW natural gas-fired power plant consisting of two 62 MW combustion turbines. The power plant reached commercial operation in June 2010. Service under the contract commenced on May 1, 2019.

Existing Hydropower

Southeastern Power Administration Member Resource – 32 MW

The KYMEA AR Project members entered into agreements for KYMEA to integrate their entitlements to hydroelectric power from the Southeastern Power Administration (SEPA) as part of the AR Project power supply portfolio. The SEPA entitlements are derived from nine hydroelectric plants of the U.S. Army Corps of Engineers' Cumberland System of Projects located in Kentucky and Tennessee, which totals 927 MW of nameplate capacity. The first unit reached commercial operation in December 1948, and the newest unit reached commercial operation in November 1977. Service under the contracts commenced on May 1, 2019.

Existing Diesel Power

City of Paris Power Plant PPA – 11 MW

The City of Paris and KYMEA entered into a power supply contract for 11 MW of capacity and energy from the Paris Power Plant. The Paris Power Plant, located in central Kentucky, is an 11.9 MW distillate fuel oil-fired power plant consisting of seven internal combustion turbines. The first unit reached commercial operation in December 1934, and the newest unit reached commercial operation in December 1974. The units range in size from 0.7 MW to 3.1 MW. Service under the contract commenced on May 1, 2019.



4.4 KYMEA Transmission

KYMEA purchases network integrated transmission service (NITS) from LG&E/KU to serve nine of its members. Billing for NITS is calculated based on monthly coincident peaks. Falmouth receives transmission service from PJM, as it is physically located within PJM's footprint. KYMEA resides within the LG&E/KU BA; therefore, access to MISO and PJM requires point-to-point transmission service to move energy from those systems to the interface of LKE. Firm transmission service is subject to availability and typically requires procurement well in advance of usage due to required system impact studies and potential facility studies. To move energy associated with KYMEA's existing power supply portfolio, KYMEA has purchased the necessary transmission service to move energy to the KYMEA load delivery point.

KYMEA Resource Transmission Portfolio

A summary of the resource transmission portfolio showing the provider and service is detailed in Table 4.4-1.

Table 4.4-1: KYMEA Resource Transmission Portfolio

Provider	Source	Sink	Type	Capacity (MW)	Start	Stop	Rollover Rights
MISO	BREC.Wilson.1	LGEE	PTP	100	Present	April 30, 2029	Yes
MISO	BREC.Wilson.1	LGEE	PTP	62	Present	April 30, 2027	Yes
MISO	CIN.Cayuga 1	LGEE	PTP	38	Present	April 30, 2027	Yes
LGEE	GLHB	LGEE.KYMA	NITS	100	Present	May 31, 2022	Yes
LGEE	LGEE.Paris	LGEE.KYMA	NITS	11	Present	May 31, 2029	Yes
LGEE	LGEE.KMPA	LGEE.KYMA	NITS	90	Present	April 30, 2027	Yes
LGEE	MISO	LGEE.KYMA	NITS	38	Present	April 30, 2027	Yes
LGEE	MISO	LGEE.KYMA	NITS	162	Present	April 30, 2027	Yes
LGEE	TVA	LGEE.KYMA	NITS	33	Present	April 30, 2027	Yes
LGEE	Ashwood Solar I	LGEE.KYMA	NITS	54	December 1, 2022	November 30, 2042	Yes
TVA	TVA	LGEE	PTP	33	Present	GF*	GF*

*A grandfather clause (grandfather policy or grandfathering) is a provision in which an old rule continues to apply to some existing situations while a new rule will apply to all future cases. Those exempt from the new rule are said to have grandfather rights or acquired rights, or to have been grandfathered in.



KYMEA IRP2020 Participant Location

As shown in Figure 4.4-1, the IRP2020 participants are located across the Commonwealth. With the exception of Falmouth who is in PJM, the communities reside in the LG&E/KU BA area.



Figure 4.4-1: KYMEA IRP2020 Participant Map

Member Primary Voltage and Delivery Points

Table 4.4-2 details each member community delivery service. All members receive their power at 69 kV which is classified as medium voltage. High voltage is classified as 100 kV or greater.

Table 4.4-2: Member Primary Voltage and Delivery Points

Member	Service	Balancing Authority	Primary Voltage (kV)	Delivery Points
Barbourville	All-Requirements	LG&E/KU	69	1
Bardwell	All-Requirements	LG&E/KU	69	1
Benham	Transmission	LG&E/KU	69	1
Berea	Transmission	LG&E/KU	69	2
Corbin	All-Requirements	LG&E/KU	69	2
Falmouth	All-Requirements	PJM	69	1
Frankfort	All-Requirements	LG&E/KU	69	2
Madisonville	All-Requirements	LG&E/KU	69	6
Paris	All-Requirements	LG&E/KU	69	4
Providence	All-Requirements	LG&E/KU	69	2



4.5 Transmission and Resource Risks

Transmission Risks

To deliver power from KYMEA's portfolio to the members' loads, firm transmission has been procured. While the transmission path is firm, there is still a risk that a firm path will be unavailable due to transmission curtailment and ramp risk.

- **Curtailment:** Curtailment, or a reduction of energy delivery, can occur when the transmission system becomes overloaded. This overloading can be caused by increased usage due to demand or by other parts of the system going offline. These circumstances force flows to increase on surrounding systems. Curtailments are done on a pro-rata basis that is determined by the level of firmness of the entire transmission path. The NERC transmission service priorities are shown in Table 4.5-1.

Table 4.5-1: Transmission Service Reservation Priorities⁸

Transmission Service Reservation Priorities		
Priority	Acronym	Name
0	NX	Next-hour Market Service
1	NS	Service Over Secondary Receipt and Delivery Points
2	NH	Hourly Service
3	ND	Daily Service
4	NW	Weekly Service
5	NM	Monthly Service
6	NN	Network Integration Transmission Service from sources not designated as network resources
7	F	Firm Point-to-Point Transmission
	FN	Network Integration Transmission Service from Designated Resources

- **Ramp risk:** Ramp risk is centered around a BA's ability to accommodate net schedule changes into or out of their respective areas. The BA must dispatch their generating portfolios within the operational limitations of each unit. As such, when a market participant wishes to make scheduling changes, the BA must determine if such a change is feasible. Ramp is determined on a first-come, first-served basis.

Resource Risks

There are also availability and price risks associated with the existing resources. These risks are described below:

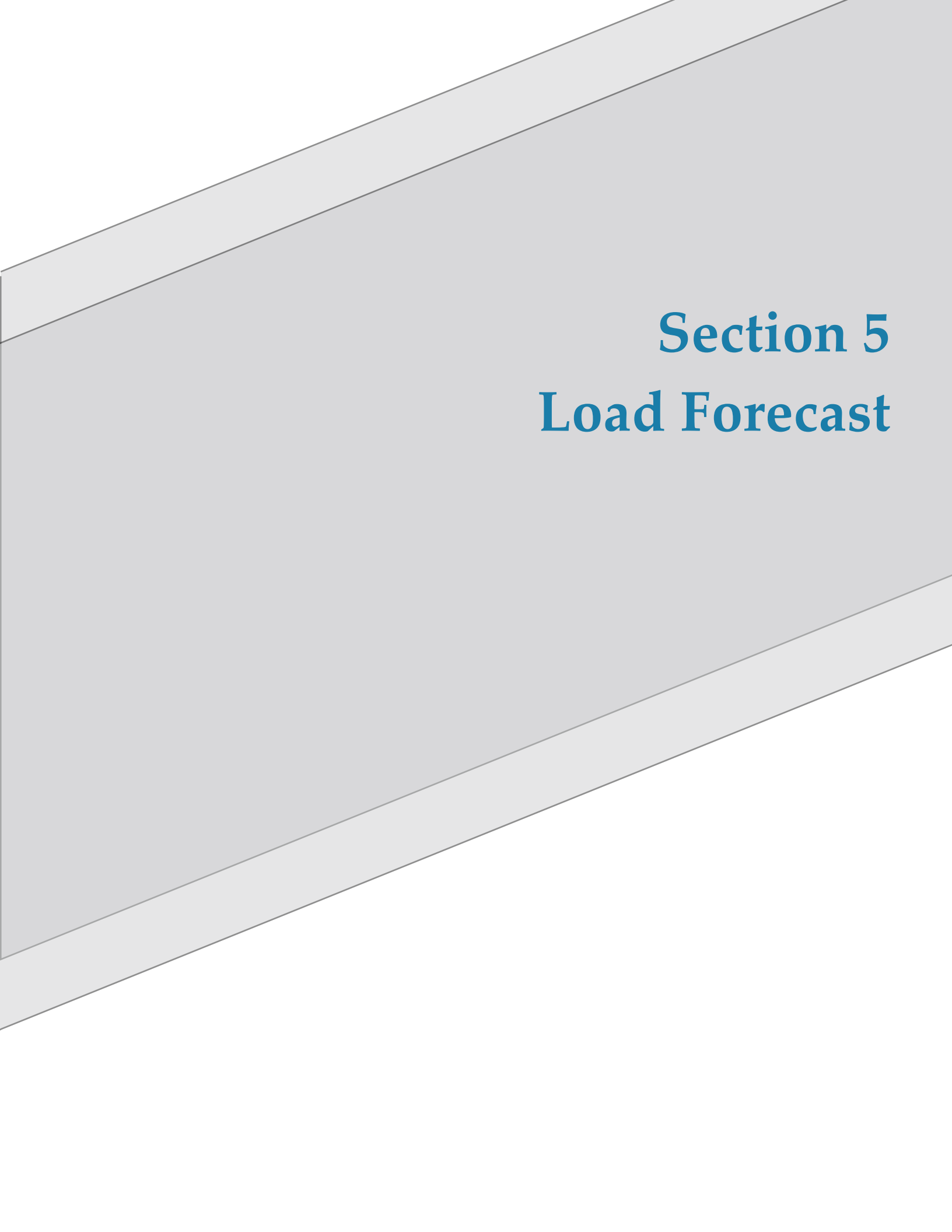
- **Availability risk:** Availability risk is the likelihood that a particular resource will be able to generate when called upon. Differing technologies, maintenance practices, fuel supplies and transmission capabilities affect this risk which is typically measured as a percentage with 100% representing full-time availability.
- **Price risk:** Price risk is the risk that the value of an asset declines if you are long (own) the asset and the risk that prices increase if you are short (need) the asset. Prices are determined by fuel costs, O&M costs, regulatory compliance costs and congestion costs.



Table 4.5-2 identifies the risks of KYMEA’s existing resource portfolio. For example, the BREC D.B. Wilson PPA is 100% available, so there is no availability risk associated with that particular resource.

Table 4.5-2: KYMEA Resource Risk

Resource	Curtailment Risk	Ramp Risk	Availability Risk	Price Risk	Fuel Risk
BREC D.B. Wilson	X	X		X	X
IPMC Joppa	X		X	X	X
PPS Plant 1	X		X	X	X
SEPA	X		X		
Paris	X		X	X	X



Section 5

Load Forecast

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5. LOAD FORECAST

5.1 Forecast Methodology Overview

NewGen Strategies & Solutions (NewGen) prepared the IRP2020 load forecast. NewGen has worked with KYMEA member systems for over twenty years to prepare load forecasts as part of their power supply planning process. More recently, NewGen has prepared an annual NERC MOD-032 compliance filing for each of the following Kentucky systems, which are members of KYMEA:

1. Barbourville Utility Commission
2. Bardwell City Utilities
3. Benham Power Board
4. City of Berea Municipal Utilities
5. City Utilities Commission of Corbin
6. City of Falmouth⁹
7. Frankfort Plant Board
8. Madisonville Electric Department
9. City of Paris Combined Utilities
10. City of Providence Utilities

The KYMEA load forecasts are developed using a regression analysis through which past variation in a dependent variable is explained by past variation in independent variables. For the KYMEA members, historic load data is the dependent variable, and past changes in load are explained as a function of past changes in weather, economics, and other data points, each of which are independent variables. Mathematically these equations take the form:

$$Y = \beta_0 + \beta_1 x_1 + \beta_2 x_2 + \dots$$

Where Y represents the forecasted load, β_0 represents the constant, β_1 , β_2 , et cetera represent the coefficients, and x_1 , x_2 , et cetera represent the independent variables (e.g., weather, economics, ...). Coefficients for the independent variables are shown in the tables in Section 5.2.

Regression equations are developed to maximize the explanatory power of the forecast based on the following metrics:

1. The R-squared metric of the regression equation;
2. The statistical significance of each variable within the regression equation;
3. The accuracy of the regression equation as applied to past load (“back-casting” results);
4. Mitigation of residual trends in back-casting (i.e., time-based trends in residuals);
5. Intuitive results of identified independent variables and coefficients (i.e., positive coefficients for variables that drive increased electric consumption and negative coefficients for variables that drive decreased electric consumption, all else equal), and
6. Other considerations as appropriate such as interviews with members to explore local load issues related to economic development or loss of customers with significant load.

⁹ Falmouth did not require a MOD-032 filing in 2020, but for KYMEA’s planning purposes an updated forecast was developed based on the past forecasting methodology including most recent data.



NERC MOD-032 reporting requires a stochastic forecast that expresses future seasonal peak demand by delivery point at certain confidence intervals. The 50/50 load forecast represents a 50% probability that the actual load will be above this forecast and a 50% probability that the load is below this forecast. The 90/10 forecast captures 90% of future variation in actuals from the 50/50 case. Monte Carlo modeling is utilized to vary certain independent variables based on history and produce a demand forecast at these confidence intervals. The Monte Carlo model runs 10,000 iterations of varied independent variables, and produces a monthly energy and demand forecast for each member, capturing the forecast for each simulation and combining all simulations to produce a forecast value at a given confidence interval.

For KYMEA's members other than Frankfort and Madisonville, the KYMEA load forecast developed a member system-level forecast based on hourly load data.

For KYMEA's largest members (Frankfort and Madisonville), a bottom-up forecast of retail energy sales for individual customer classes is developed. Past retail sales by class are collected from each member to develop monthly values for electric usage per customer per day as the independent variable. In the last 10-15 years, energy efficiency measures including high-efficiency HVAC systems, LED lighting, and efficient building standards have increased in prevalence. Forecasting both usage per customer and the number of customers separately captures two distinct and important drivers for change in customer electric consumption. This approach improves the accuracy of the forecast equation.

As mentioned above, key datapoints used in developing the load forecast include weather data, economic data, and other data points as appropriate. An explanation of the sources for such data and how each point is used in the forecasts is provided in the following sections.

Weather Data

A key predictor for changes in electric consumption is weather. Figure 5.1-1 illustrates a common relationship between average temperature and electric usage per customer per day.

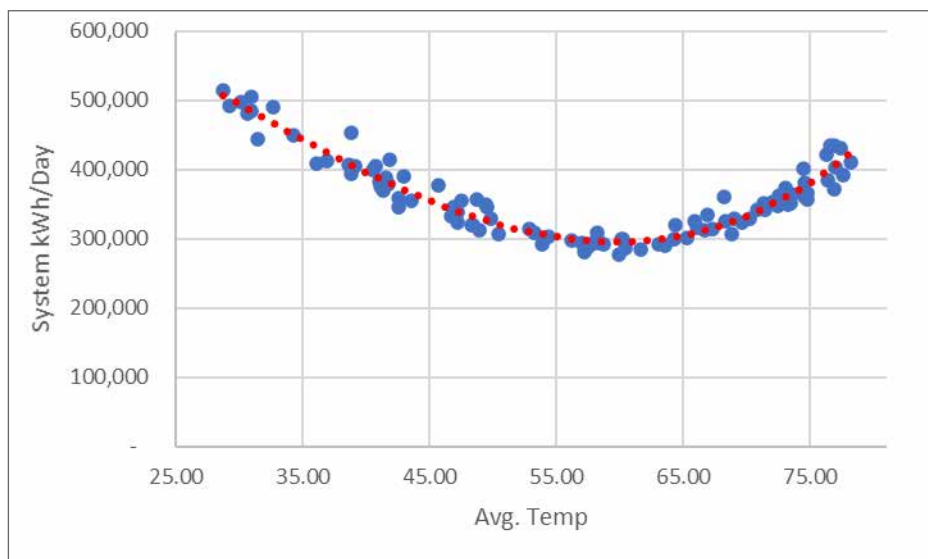


Figure 5.1-1: Relationship Between Average Temperature and Electric Usage

As Figure 5.1-1 demonstrates, there is a positive relationship between electric usage for increasing average temperatures above roughly 65 degrees, as well as for decreasing temperatures below roughly 55 degrees. Similar relationships are observed across all electric utilities as there is a strong correlation between temperature and space conditioning requirements and electric consumption. Where electric heating is not common, there will be little to no trend in electric consumption as average temperatures decrease below ~55-65 degrees. However, in such territories there may still



be a positive correlation between electric consumption and increasing temperatures as electric air conditioning is used more frequently to cool spaces at higher temperatures.

For each member forecast, the KYMEA forecast compiles data from the National Oceanic and Atmospheric Administration on daily maximum and minimum temperatures for a weather station located near to the KYMEA member. Maximum and minimum temperatures are then translated to “degree days” by taking the average of the maximum and minimum temperature for the day as compared to some threshold value. Traditionally, a “Cooling Degree Day” (CDD) is defined as the amount that the daily average temperature exceeds 65 degrees, and a “Heating Degree Day” (HDD) is defined as the amount that 65 degrees exceeds the average daily temperature. 65 degrees is the traditional threshold for both CDD and HDD, but depending on the specific electric usage patterns of a service territory, other thresholds may be more appropriate. The forecast analyzes the “fit” of different cutoffs for CDD and HDD, and ultimately selects a value that maximizes the forecast regression’s predictive power. Where data does not suggest substantial electric heating, HDD is not used in the regression equation at all; and the forecast also analyzes both linear and parabolic relationships between electric usage and CDD/HDD. To reflect a parabolic “shape,” the forecast will introduce a squared CDD or HDD term where appropriate. The forecast decides on a specific cutoff to CDD and HDD based on the weather variable’s statistical significance (p-value less than 5.0) and a corresponding increase in the regression equation’s R-squared metric.

In developing the member forecasts, the forecast normalizes historic weather using long-run averages for degree days by month using the CDD/HDD cutoffs selected for each member. These long-run averages are simulated in the Monte Carlo model as constrained by historic standard deviation in degree days from the long-run average.

Specifics around the different cutoffs used in each forecast is provided for each member below.

Economic Data

In addition to weather, economic factors also have a positive correlation to electric consumption. To include such a variable in developing the member forecasts for KYMEA, the Kentucky State Profile from Woods & Poole Economics was purchased. Woods & Poole’s state profiles contain actual economic data going back to 1970 recorded on an annual basis as well as forecast data for the same variables going out to 2050. Such data is available for Core-Based Statistical Areas (CBSAs) and Metropolitan Statistical Areas (MSAs), as defined by the U.S. Census Bureau. Use of MSAs is appropriate for both the Madisonville and Frankfort forecasts, with CBSAs used for the other member forecasts.

The categories of data that the Woods & Poole dataset provides includes the following:

- Population Count
- Household Count
- Persons per Household
- Population Age
- Total Employment and by Sector
- Total Earnings and by Sector
- Total Sales and by Sector
- Personal Income
- Economic Wealth Indices
- Gross Regional Product

For each member forecast, the forecast evaluates available demographic and economic data for the member’s location. Each economic datapoint and various combinations are evaluated to determine statistical significance, a maximized R-squared metric, and a positive coefficient within the regression equation.



The forecast commonly relies on population or household counts to explain past and forecast customer counts where appropriate. Further, the forecast also commonly looks at Earnings by Sector or Employment by Sector to explain changes in the local economy that would drive an increase in electric consumption. For many, the forecast develops a “composite” of certain sectors within the earnings and/or employment datasets, whereby a cumulative total of certain sectors is combined to produce a single variable of statistical significance, that maximizes R-squared and produces a positive coefficient within the regression equation. A positive coefficient is important as it suggests that as economic activity increases for the combined sectors, electric consumption also increases.

Specifics around the different economic and demographic data points used in each forecast is provided for each member below.

Binary Variables and Residual Trend Analysis

In addition to weather and economic data, the forecast also analyzes trends in residuals resulting from a comparison of a back-cast forecast against historic actuals. A proper forecast regression equation will have some variance from actuals when compared to back-cast actuals; however, a highly predictive forecast will not typically have trends in residuals, which would imply that there is something in the underlying changes to electric usage that has not been explained in the forecast regression equation. The forecast analyzes longer-term trends over a single year or multiple years, or within certain months across the forecast. A common longer-term trend may be observed pre- and post-2008 when the global economic downturn coincided with substantial investment in energy efficiency and electric usage decoupled from GDP. Introducing a forecasting binary variable (1 or 0 indicating before or after some date) can mitigate longer-term residual trends that cannot be mitigated by reliance on economic data to explain a similar phenomenon. Monthly residuals are common during shoulder months (spring and fall) when temperatures can vary substantially.

Figure 5.1-2 provides an example of using a binary variable to mitigate trends in residuals.

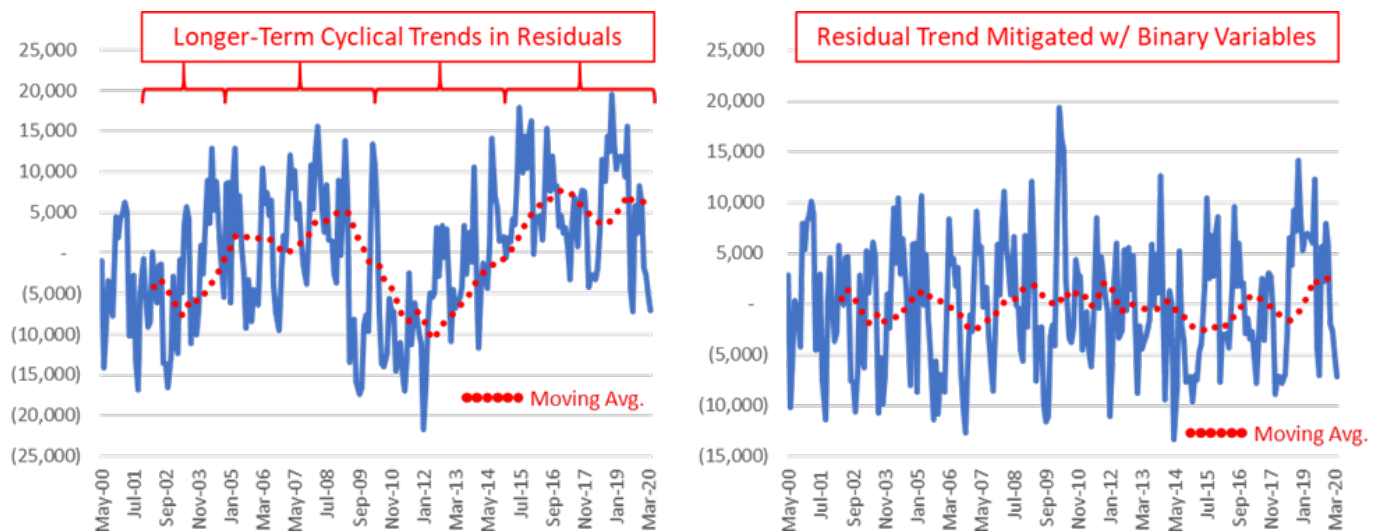


Figure 5.1-2: Binary Variable Utilized to Mitigate Trends in Residuals



Binary Variable for COVID-19 Impacts

For three KYMEA members (Frankfort, Madisonville, and Berea), the forecast identified a statistically significant change in electric consumption in March 2020, coinciding with the beginning of regulations pertaining to the COVID-19 pandemic. In each case for these three members, load decreased relative to what our regression equations would have predicted without the introduction of a COVID-19 binary variable.

Specifics around different binary variables used in each forecast is provided for each member below.

Member-Level Peak Demand Forecast

For all member forecasts, the KYMEA forecast produces a monthly energy forecast. A monthly member-level peak demand (Non-Coincident Peak, or NCP) forecast is then derived from the energy forecast using past monthly load factor. Monthly load factors are varied in the Monte Carlo Simulation as constrained by historic variance, and are applied to the monthly energy forecast to calculate demand. Monthly load factors are derived from hourly interval load data available from KYMEA beginning January 1, 2010.

MOD-032 Demand Forecast by Delivery Point

For compliance with MOD-032 requirements, the forecast develops a demand forecast by delivery point. This delivery-point level forecast is derived from the member monthly NCP demand forecast using historical delivery-point proportionate share of the member's peak demand.



5.2 KYMEA Member Individual Forecasts

For the purposes of NERC MOD-032 compliance, the forecast also developed a 50/50 and a 90/10 demand and energy forecast for all KYMEA's IRP2020 participants. A forecast for Falmouth was not to be filed, but the forecast updated the 2019 forecast for Falmouth for KYMEA's planning purposes. In the sub-sections that follow, a summary is provided of the member-specific forecast regression equations and historic and forecast demands for each KYMEA member. For MOD-032, all member forecasts are developed at the transmission service voltage; however, all load information presented herein for either the member or the combined KYMEA forecasts presented in Section 5.3 is grossed up to generation voltage by applying a 1.02048 loss factor to load at transmission voltage. Further, 2021 is the first forecast year for MOD-032, and as of this study date, 2020 contained only a partial year of actual data; consequently, 2020 is blank in all forecasts.

Barbourville, KY – Member System-Level Forecast

The regression equation used to forecast Barbourville's monthly energy and peak demand used both CDD and HDD, with a degree day cutoff of 66.0 and 50.1, respectively. In addition, Woods & Poole data for Gross Regional Product is used as an indicator of the local economy as it relates to electric consumption, and binary variables are used for load after 2017, load after 2012, and load occurring in a shoulder season (spring or fall). The individual components of the regression equation and the coefficients for each independent variable are provided in Table 5.2-1.

Table 5.2-1: Barbourville – Regression Equation Detail

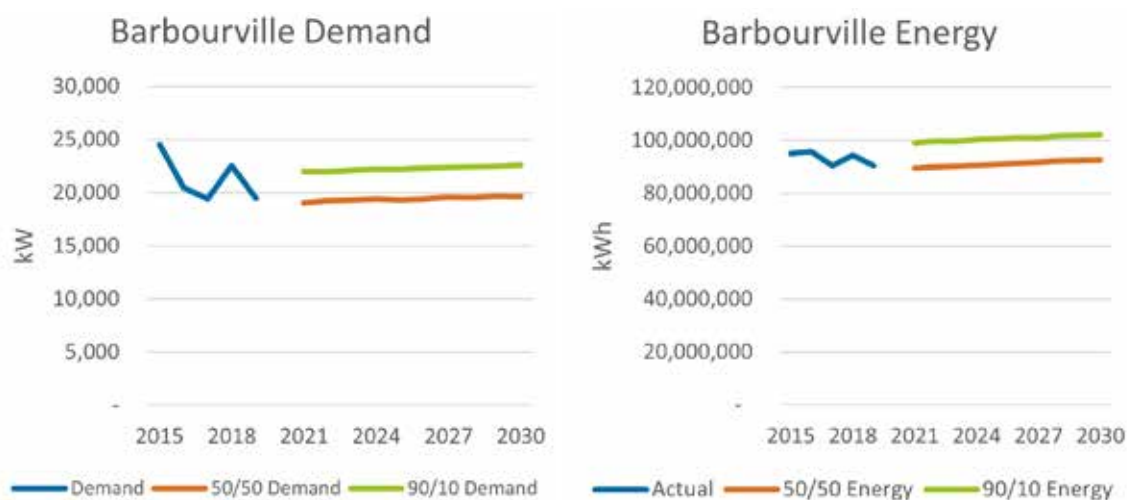
Independent Variable (X_n)	Gross Regional Product (in millions of 2012 dollars)	Post 2017	Post 2012	Shoulder Season	HDD/day $\wedge^1$	CDD/day $\wedge^1$	Constant
Constants and Coefficients (β_n)	155.79	(15,092.80)	(27,473.95)	(5,648.55)	5,749.94	9,566.83	134,948.89

Table 5.2-2 and Figure 5.2-1 provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

**Table 5.2-2: Barbourville – Forecast (kW and kWh)**

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	24,450			94,778,526		
2016	20,389			95,535,490		
2017	19,351			90,302,012		
2018	22,493			94,299,058		
2019	19,422			90,308,272		
2020						
2021		18,984	21,926		89,256,980	98,839,861
2022		19,205	21,956		89,726,951	99,481,452
2023		19,268	22,062		90,039,759	99,556,967
2024		19,341	22,167		90,540,123	100,129,625
2025		19,278	22,160		90,710,439	100,428,979
2026		19,349	22,242		91,028,641	100,761,548
2027		19,524	22,337		91,503,181	100,909,054
2028		19,458	22,372		91,956,592	101,561,741
2029		19,614	22,429		92,166,280	101,726,829
2030		19,572	22,518		92,404,046	101,935,308
2015-2019 CAGR	(4.50%)			(0.96%)		
2021-2030 CAGR		0.31%	0.27%		0.35%	0.31%

As the table above and figure below demonstrate, the forecast projects an increase to Barbourville’s demand and energy sales over the forecast period. This growth estimate results from Woods & Poole’s forecast for Regional GDP in Knox County, which is forecast to grow by 0.9% each year.

**Figure 5.2-1: Barbourville - Forecast Graph**



Bardwell, KY – Member System-Level Forecast

The regression equation used to forecast Bardwell's monthly energy and peak demand used both CDD and HDD, with a degree day cutoff of 56.5 and 65.0, respectively. In addition, Total Population data is used as an indicator of the local economy as it relates to electric consumption. The individual components of the regression equation and the coefficients for each independent variable are provided in Table 5.2-3.

Table 5.2-3: Bardwell – Regression Equation Detail

Independent Variable (X_n)	Total Population (in thousands)	HDD/day $\wedge 1$	CDD/day $\wedge 2$	CDD/day $\wedge 1$	Constant
Constants and Coefficients (β_n)	3,622.79	438.75	13.62	523.32	(4,838.74)

Table 5.2-4 and Figure 5.2-2 provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

Table 5.2-4: Bardwell – Forecast (kW and kWh)

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	2,283			9,179,336		
2016	2,306			9,424,379		
2017	2,208			8,742,204		
2018	2,236			9,502,258		
2019	2,104			8,943,877		
2020						
2021		2,207	2,544		8,810,881	9,901,281
2022		2,204	2,547		8,793,800	9,887,837
2023		2,201	2,543		8,781,709	9,875,210
2024		2,197	2,541		8,779,235	9,870,294
2025		2,196	2,532		8,750,629	9,848,157
2026		2,196	2,531		8,734,875	9,830,262
2027		2,191	2,528		8,722,566	9,817,501
2028		2,187	2,526		8,719,555	9,817,529
2029		2,185	2,527		8,694,534	9,789,804
2030		2,183	2,520		8,679,769	9,770,787
2015-2019 CAGR	(1.62%)			(0.52%)		
2021-2030 CAGR		(0.11%)	(0.09%)		(0.15%)	(0.13%)



As the table above and figure below demonstrate, the forecast projects a decline to Bardwell’s demand and energy sales over the forecast period. This decline results from Woods & Poole’s forecast for Total Population in Carlisle County, which is estimated to decline by an average of -0.2% each year between 2020-2032.

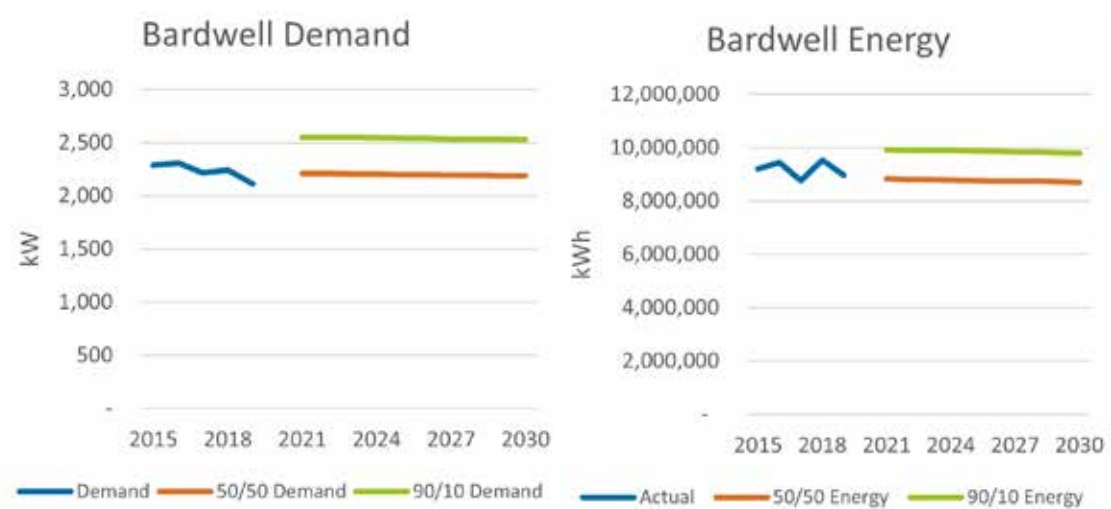


Figure 5.2-2: Bardwell – Forecast Graph



Benham, KY – Member System-Level Forecast

The regression equation used to forecast Benham's monthly energy and peak demand used both CDD and HDD, with a degree day cutoff of 64.3 and 57.9, respectively. In addition, Total Employment (in thousands of jobs) is used as an indicator of the local economy as it relates to electric consumption, and binary variables are used for the month of February and for years prior to 2011. The individual components of the regression equation and the coefficients for each independent variable are provided in Table 5.2-5.

Table 5.2-5: Benham – Regression Equation Detail

Independent Variable (X_n)	Total Employment (in thousands of jobs)	Month 2	Pre 2011	HDD/day $\wedge 1$	CDD/day $\wedge 1$	Constant
Constants and Coefficients (β_n)	295.45	(1,048.81)	1,277.79	829.46	541.64	6,603.38

Table 5.2-6 and Figure 5.2-3 provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

Table 5.2-6: Benham – Forecast (kW and kWh)

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	2,700			6,490,103		
2016	2,504			6,509,827		
2017	2,395			6,140,143		
2018	2,972			6,789,999		
2019	2,468			6,204,424		
2020						
2021		2,380	2,895		6,393,495	7,562,207
2022		2,383	2,891		6,390,118	7,549,968
2023		2,379	2,895		6,387,326	7,553,431
2024		2,376	2,894		6,394,511	7,559,536
2025		2,381	2,897		6,382,882	7,553,797
2026		2,378	2,893		6,382,578	7,549,037
2027		2,379	2,891		6,374,630	7,537,670
2028		2,376	2,889		6,376,887	7,546,938
2029		2,375	2,888		6,370,664	7,534,290
2030		2,378	2,887		6,368,544	7,537,591
2015-2019 CAGR	(1.79%)			(0.90%)		
2021-2030 CAGR		(0.01%)	(0.03%)		(0.04%)	(0.03%)

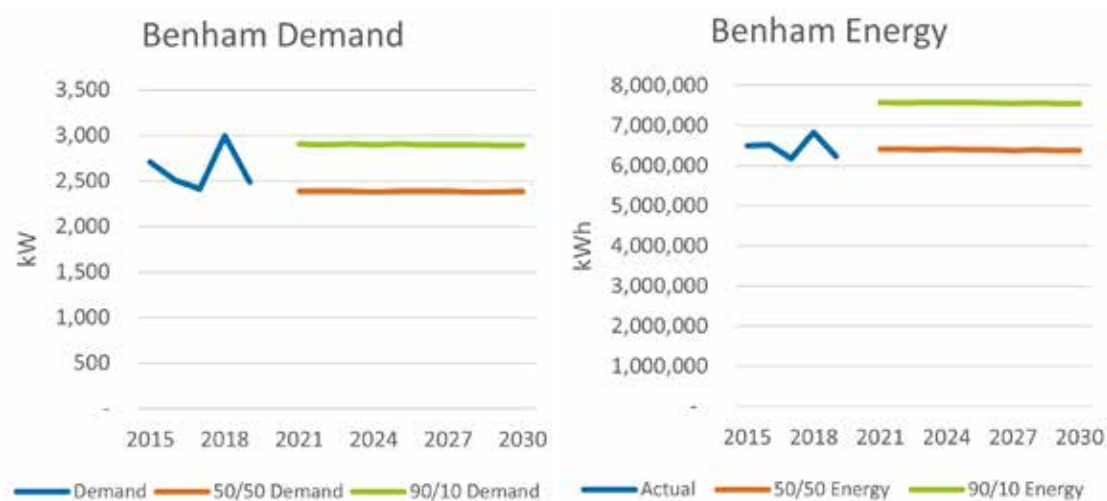


Figure 5.2-3: Benham – Forecast Graph

As the table and figure above demonstrate, KYMEA forecasts a decline to Benham’s demand and energy sales over the forecast period. This decline results from Woods & Poole’s forecast for Total Employment in Harlan County, which is estimated to decline by an average of -0.4% each year between 2020-2032.



Berea, KY – Member System-Level Forecast

The regression equation used to forecast Berea's monthly energy and peak demand used both CDD and HDD, with a degree day cutoff of 65.6 and 51.1, respectively. In addition, binary variables are used for load prior to 2012 and to control for the impacts of COVID-19. The COVID-19 binary variable is set to 1 for six months starting in March 2020. In October 2020, the COVID-19 variable is reduced to 0.75 for three months; in January 2021 it is set to 0.50 for six months; and in June 2021 it is set to 0.25 for 12 months at which point it is set to 0.0. Predicting the impacts of the COVID-19 pandemic on future electric usage is difficult due to a lack of information. Insofar as future impacts of COVID-19 vary from those estimated for forecasting purposes herein, forecast electric consumption will also vary accordingly.

The individual components of the regression equation and the coefficients for each independent variable are provided in Table 5.2-7.

Table 5.2-7: Berea – Regression Equation Detail

Independent Variable (X_n)	Pre 2012	COVID-19	HDD/day $\wedge_1$	CDD/day $\wedge_1$	Constant
Constants and Coefficients (β_n)	18,804.75	(19,553.46)	9,922.46	11,023.81	276,528.82

Table 5.2-8 and Figure 5.2-4 provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

Table 5.2-8: Berea – Forecast (kW and kWh)

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	38,239			130,105,006		
2016	29,723			132,156,084		
2017	28,538			126,288,635		
2018	34,657			138,128,879		
2019	31,242			134,809,020		
2020						
2021		31,141	36,280		129,581,565	142,714,476
2022		31,484	36,717		131,456,149	144,577,691
2023		31,815	37,101		132,293,445	145,421,684
2024		31,819	37,043		132,608,117	145,792,976
2025		31,838	37,028		132,311,429	145,487,520
2026		31,822	36,958		132,302,510	145,426,845
2027		31,835	37,075		132,325,760	145,418,906
2028		31,866	37,042		132,603,985	145,731,204
2029		31,877	37,064		132,306,482	145,497,525
2030		31,810	37,036		132,313,203	145,475,650
2015-2019 CAGR	(3.96%)			0.71%		
2021-2030 CAGR		0.21%	0.21%		0.21%	0.19%

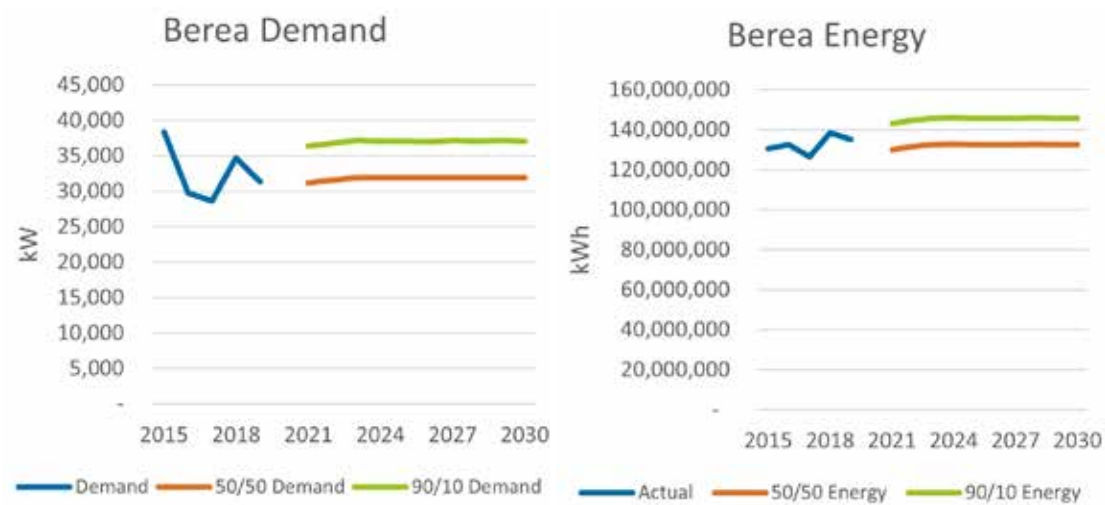


Figure 5.2-4: Berea – Forecast Graph

As the table and figure above demonstrate, KYMEA forecasts an increase to Berea’s demand and energy sales over the forecast period. This increase results from growth over the lower starting point of the forecast stemming from controlling for COVID-19 impacts. KYMEA has not identified a statistically significant economic variable to explain past fluctuations in load on which an econometric forecast of Berea’s load may be based.



Corbin, KY – Member System-Level Forecast

The regression equation used to forecast Corbin's monthly energy and peak demand used both CDD and HDD, with a degree day cutoff of 67.0 and 47.6, respectively. In addition, a combined proxy for Earnings derived from Woods & Poole¹⁰ data is used as an indicator of the local economy as it relates to electric consumption, and a binary variable is used for load after 2018. The individual components of the regression equation and the coefficients for each independent variable are provided in Table 5.2-9.

Table 5.2-9: Corbin – Regression Equation Detail

Independent Variable (X_n)	Earnings Proxy (in millions of 2012 dollars)	Post 2018	HDD/day $\wedge 1$	CDD/day $\wedge 1$	Constant
Constants and Coefficients (β_n)	416.25	(9,028.59)	4,336.77	11,285.23	60,647.35

Table 5.2-10 and Figure 5.2-5 provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

Table 5.2-10: Corbin – Forecast (kW and kWh)

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	18,878			84,421,265		
2016	19,792			86,837,371		
2017	18,588			81,943,747		
2018	18,707			87,747,836		
2019	19,433			85,426,250		
2020						
2021		19,170	21,981		83,921,211	94,476,892
2022		19,274	22,141		84,424,517	95,539,053
2023		19,424	22,347		84,945,797	96,455,588
2024		19,506	22,459		85,737,389	97,689,991
2025		19,611	22,664		86,020,896	98,499,597
2026		19,697	22,895		86,625,070	99,529,472
2027		19,801	23,049		87,138,459	100,606,959
2028		19,893	23,237		87,923,408	101,798,567
2029		19,991	23,399		88,276,731	102,718,085
2030		20,125	23,633		88,891,290	103,739,705
2015-2019 CAGR	0.58%			0.24%		
2021-2030 CAGR		0.49%	0.73%		0.58%	0.94%

10 A proxy earnings indicator was developed from Woods & Poole data by combining data for the farming, construction, manufacturing, professional and tech service(s), management of companies and enterprises, admin and waste, arts/entertainment, accommodation and food service(s), federal civilian gov't, federal military, state and local gov't sectors.

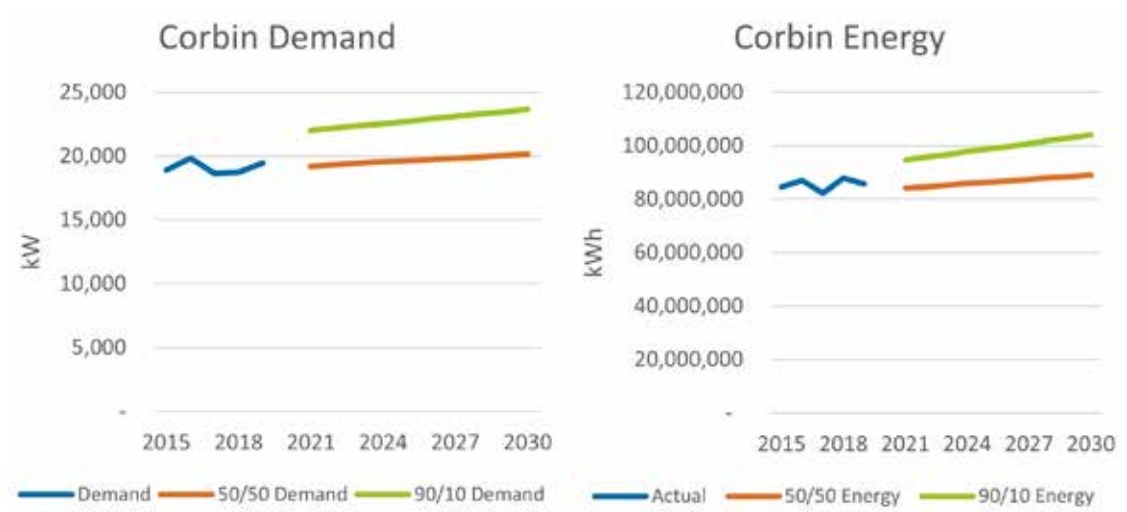


Figure 5.2-5: Corbin – Forecast Graph

As the table and figure above demonstrate, KYMEA forecasts an increase to Corbin’s demand and energy sales over the forecast period. This increase results from growth in the proxy earnings indicator derived from Woods & Poole’s economic data, which is forecast to grow at 1.3% per year in Whitley County between 2020-2032.



Falmouth, KY – Member System-Level Forecast

A load forecast for Falmouth¹¹ was not prepared for the MOD-032 filing. However, for planning purposes KYMEA updated the data and forecast for Falmouth based on previous years.

The regression equation used to forecast Falmouth's monthly energy and peak demand used both CDD and HDD, with a degree day cutoff of 64.0 and 55.0, respectively. In addition, a combined proxy for Earnings created from Woods & Poole¹² data is used as an indicator of the local economy as it relates to electric consumption, and binary variables were used for the month of December and for years after 2018. The individual components of the regression equation and the coefficients for each independent variable are provided in Table 5.2-11.

Table 5.2-11: Falmouth – Regression Equation Detail

Independent Variable (X_n)	Composite Employment (in thousands of jobs)	Month 12	Post 2018	HDD/day $\wedge 1$	CDD/day $\wedge 1$	Constant
Constants and Coefficients (β_n)	7,562.52	1,809.61	(1,919.04)	707.09	2,206.53	17,644.08

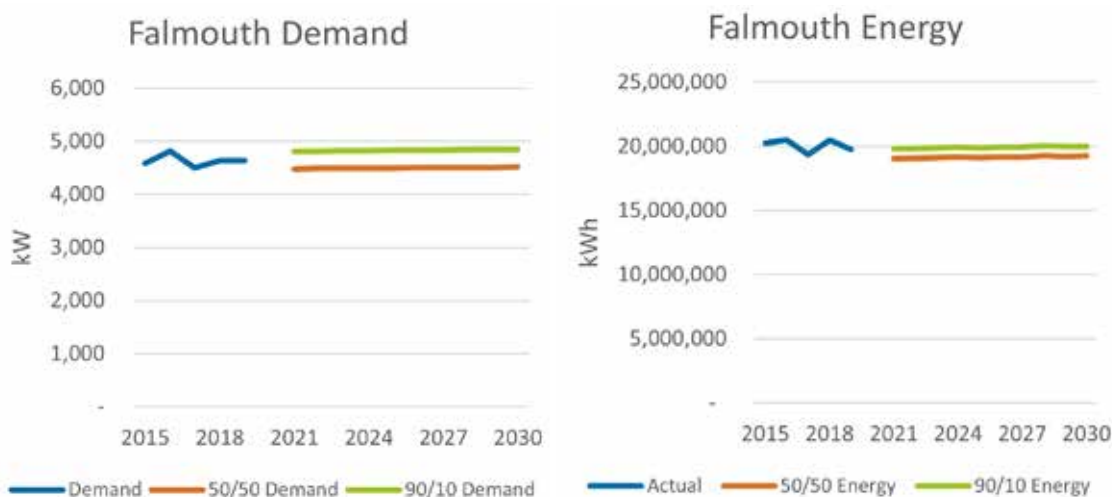
Table 5.12-12 and Figure 5.2-6 below provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

¹¹ Falmouth did not require a MOD-032 filing in 2020, but for KYMEA's planning purposes, an updated forecast was developed based on the past forecasting methodology including most recent data.

¹² A proxy employment indicator was developed from Woods & Poole data by combining employment for the farming, forestry, mining, wholesale trade, retail, admin and waste service(s), education, healthcare, and other services except pub administration, federal civilian government, federal military employment, state and local government sectors.

**Table 5.2-12: Falmouth – Forecast (kW and kWh)**

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	4,570			20,209,998		
2016	4,802			20,464,855		
2017	4,486			19,326,196		
2018	4,628			20,429,134		
2019	4,629			19,689,758		
2020						
2021		4,467	4,799		19,007,904	19,778,248
2022		4,479	4,804		19,031,345	19,799,420
2023		4,479	4,815		19,054,619	19,827,148
2024		4,485	4,814		19,131,768	19,906,122
2025		4,489	4,821		19,095,818	19,869,975
2026		4,490	4,827		19,125,249	19,897,281
2027		4,497	4,819		19,132,479	19,906,710
2028		4,499	4,829		19,201,879	19,975,914
2029		4,500	4,838		19,167,284	19,937,420
2030		4,507	4,837		19,190,756	19,959,374
2015-2019 CAGR	0.26%			(0.52%)		
2021-2030 CAGR		0.09%	0.08%		0.10%	0.09%

**Figure 5.2-6: Falmouth – Forecast Graph**

As the table and Figure above demonstrate, KYMEA forecasts an increase to Falmouth’s demand and energy sales over the forecast period. This increase results from growth in the proxy employment indicator derived from Woods & Poole’s economic data, which is forecast to grow at 0.2% per year in Pendleton County between 2020-2032.



Frankfort, KY – Retail Class-Level Forecast

For Frankfort, the forecast developed a bottom-up retail class-level forecast, which was summed up for the Frankfort system. To do so, the forecast created separate forecasts for the combined Residential and Commercial classes, for the Industrial¹³ class, and for the combined Municipal (including street lighting) and Miscellaneous classes.

The regression equations used to forecast Frankfort’s three combined retail classes were developed separately as summarized below.

- **Residential and Commercial:** Monthly energy consumption per customer was forecast using both CDD and HDD, with degree day cutoffs of 60.0 and 56.0, respectively. In addition, a variable to quantify electric usage as a function of the price of electricity was also used by dividing Personal Income data from Woods & Poole with the average retail price of electricity to the end-user (the forecast defines this variable as “Purchasable kWh”). The forecast also used binary variables for load after 2004 and for the month of November. The individual components of the regression equation for the Residential and Commercial Class are provided in Table 5.2-13.

Table 5.2-13: Frankfort – Res-Comm Regression Equation Detail

Independent Variable (X_n)	Purchasable kWh (Personal Income/ Avg. Residential Retail Rate)	Post 2004	Month 11	Season Winter	HDD/day ^1	CDD/day ^1	Constant
Constants and Coefficients (β_n)	0.00	1.97	2.91	5.67	0.60	1.25	17.25

Residential and Commercial Customer Count was forecast as a function of Frankfort Population, with the following regression equation coefficient and constant; provided in Table 5.2-14

Table 5.2-14: Frankfort – Res-Comm Regression Equation Detail

Independent Variable (X_n)	Total Population (in thousands)	Constant
Constants and Coefficients (β_n)	241.13	2,815.83

- **Industrial:** Monthly energy consumption was forecast using CDD with a degree day cutoff of 50.7. In addition, a combined proxy for Earnings created from Woods & Poole¹⁴ data is used as an indicator of the local economy as it relates to electric consumption. Finally, the forecast used binary variables for the 2009 year, for years 2005-2006, for the Winter season, and for COVID-19 impacts. The COVID-19 binary variable was set to 1.0 for three months starting in March 2020, was set to 0.85 for four months starting in June 2020, was set to 0.5 for six months starting in October 2020, was set to 0.25 for twelve months starting in April 2021, and was set to 0.10 for the remainder

¹³ Based on conversations with Frankfort, NewGen understands this class includes a fair amount of load associated with State Government buildings, in addition to load more traditionally defined as being associated with industry.

¹⁴ A proxy employment indicator was developed from Woods & Poole data by combining employment for the farming, mining, manufacturing, information, finance, arts/entertainment, federal gov’t, federal military, state and local gov’t sectors.



of the forecast period starting in April 2022. The forecast projects long-term impacts of COVID-19 for the Frankfort Industrial class based on conversations with Frankfort, and an indication that some portion of state government employees may move to a permanent remote working arrangement. Predicting the impacts of the COVID-19 pandemic on future electric usage is difficult due to uncertainties associated with the pandemic and governmental mitigation strategies. Insofar as future impacts of COVID-19 vary from those estimated for forecasting purposes herein, forecast electric consumption will also vary accordingly. The individual components of the regression equation for the Industrial Class are provided in Table 5.2-15.

Table 5.2-15: Frankfort – Industrial Regression Equation Detail

Independent Variable (X_n)	2020 Proxy Frankfort Ind. Employment (in thousands of jobs)	COVID-19	Year 2009	Years 2005-2006	Season Winter	CDD/day $\wedge 1$	Constant
Constants and Coefficients (β_n)	261.68	(696.79)	(112.60)	256.21	83.34	28.80	(2,947.67)

Industrial Customer Count was held flat at the average of the previous 12 months count ending June 2020.

- Municipal and Miscellaneous:** Monthly energy consumption was forecast using both CDD and HDD, with degree day cutoffs of 55.5 and 35.5, respectively. In addition, the State Government Employment Rate was derived from Woods & Poole data to serve as an indicator of the local economy as it relates to electric consumption in this combined class. A variable for hours of darkness in each month was used in developing the regression equation for this class as a portion of load is associated with serving municipal street lighting. Finally, binary variables were used for load after October 1, 2016, and for the Winter season. The individual components of the regression equation for the Municipal and Miscellaneous Class are provided in Table 5.2-16.

Table 5.2-16: Frankfort – Mun-Misc Regression Equation Detail

Independent Variable (X_n)	State and Local Government Employment Rate	Hours of Darkness	Post 10/1/2016	Season Winter	HDD/day $\wedge 1$	CDD/day $\wedge 1$	Constant
Constants and Coefficients (β_n)	182.30	0.03	32.85	4.87	0.64	0.44	21.59

Municipal and Misc. Customer Count was forecast as a function of Frankfort Population, with the regression equation being comprised in Table 5.2-17.

Table 5.2-17: Frankfort – Res-Comm Regression Equation Detail

Independent Variable (X_n)	Total Population (in thousands)	Constant
Constants and Coefficients (β_n)	43.70	(2,124.38)



Table 5.2-18 and Figure 5.2-7 provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

As the Table 5.2-18 and Figure 5.2-7 demonstrate, the forecast projects an increase to Frankfort's demand and energy sales over the forecast period. This increase results from movement in various economic and demographic variables forecast by Woods & Poole for Frankfort for each of the retail class forecasts over the 2020-2032 period, as summarized below:

- **Residential and Commercial economic and demographic forecasts:** Energy usage per customer per day is forecast to grow based on growth in Purchasable kWh of 2.7% per year from 2020-2032. This is based on assumed KYMEA nominal rate change of 0.5% per year through December 2021, and then 2.1% per year for the rest of the forecast period; and on Woods & Poole's forecast growth of 4.65% for Household Personal Income for Frankfort from 2020-2032. Residential and Commercial Customer Count growth is driven by Woods & Poole's 0.3% forecast growth in Total Population for Frankfort.
- **Industrial economic forecast:** Usage per customer per day is forecast to decline due to Woods & Poole forecast of -0.13% annual change in the proxy indicator for employment in Frankfort from 2020-2032. Industrial Customer Count is held flat.
- **Municipal and Miscellaneous economic forecast:** Usage per customer per day is forecast to decline due to Woods & Poole forecast of -0.67% annual change in State and Local Government Employment Rate. Municipal and Misc. Customer Count is forecast to grow based on Woods & Poole's forecast increase of 0.3% per year in Total Population for Frankfort.

Table 5.2-18: Frankfort – Forecast (kW and kWh)

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	152,659			726,850,221		
2016	141,876			734,673,906		
2017	137,367			704,751,865		
2018	139,321			722,502,812		
2019	138,874			699,550,196		
2020						
2021		136,754	145,712		693,830,279	732,026,902
2022		138,827	148,235		708,326,879	746,649,241
2023		139,265	148,292		713,268,922	751,450,334
2024		139,661	148,881		717,542,935	755,895,077
2025		140,207	149,264		717,823,859	756,071,144
2026		140,479	149,644		719,776,906	758,018,953
2027		140,911	150,069		721,918,389	760,591,970
2028		141,298	150,599		725,579,060	764,451,261
2029		141,741	150,871		725,739,083	764,272,161
2030		141,924	151,000		727,699,030	766,269,858
2015-2019 CAGR	(1.88%)			(0.76%)		
2021-2030 CAGR		0.37%	0.36%		0.48%	0.46%

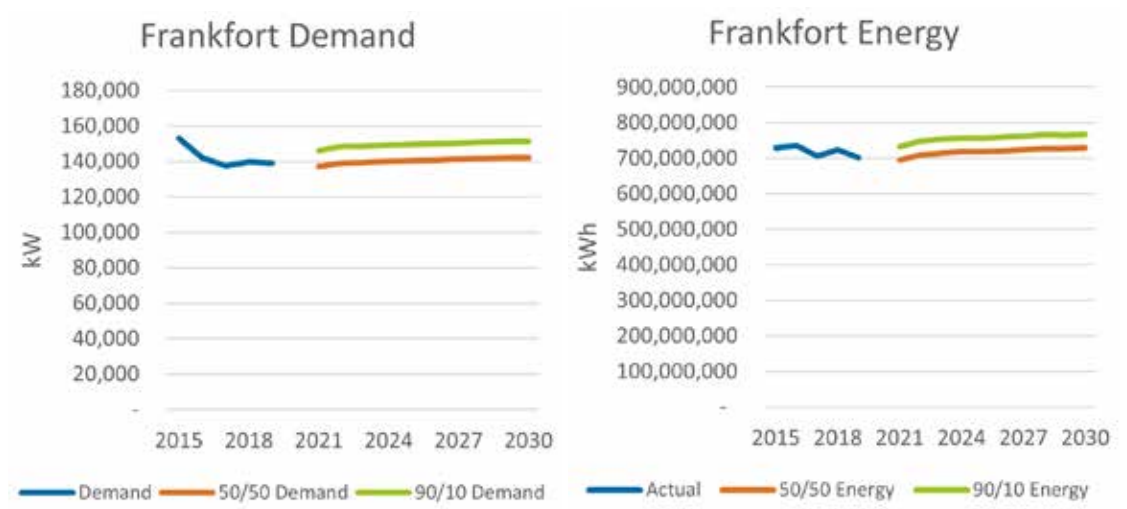


Figure 5.2-7: Frankfort – Forecast Graph



Madisonville, KY – Retail Class-Level Forecast

For Madisonville, the forecast developed a bottom-up retail class-level forecast, which was summed up for the Madisonville system. To do so, the forecast created separate forecasts for the Residential class, for a combined Commercial, Industrial, and Municipal class, and for a single large industrial user on the system.

The regression equations used to forecast Madisonville's three combined retail classes were developed separately as summarized below.

- **Residential:** Monthly energy consumption was forecast using both CDD and HDD, with degree day cutoffs of 64.9 and 58.2, respectively. In addition, Total Earnings was used from Woods & Poole to represent the local economy as it translates to Residential electric usage. Finally, the forecast also used a binary variable for load after 2011. The individual components of the regression equation for the Residential and Commercial Class are provided in Table 5.2-19.

Table 5.2-19: Madisonville – Residential Regression Equation Detail

Independent Variable (X_n)	Total Earnings (in millions of 2012 dollars)	Post 2011	HDD/day 1	CDD/day 1	Constant
Constants and Coefficients (β_n)	0.02	(1.19)	0.52	1.76	(3.00)

Residential Customer Count was forecast as a function of Madisonville Population and a binary variable for years prior to 2008. The regression equation to forecast Residential Customer Count is shown in Table 5.2-20.

Table 5.2-20: Madisonville – Res-Customer Count Regression Equation Detail

Total Population (in thousands)	Pre 2008	Constant
110.60	230.30	1,732.70

- **Commercial, Industrial, and Municipal:** Monthly energy consumption was forecast using CDD with a degree day cutoff of 64.5. In addition, a combined proxy for Earnings created from Woods & Poole¹⁵ data in addition to data for Total Employment is used as an indicator of the local economy as it relates to electric consumption. Finally, the forecast used binary variables for the 2012 and 2009 years, and for COVID-19 impacts. The COVID-19 binary variable was set to 1.0 for three months starting in March, 2020, was set to 0.75 for six months starting in June, 2020, was set to 0.5 for six months starting in December 2020, was set to 0.25 for twelve months starting in June 2021, and was set to 0.00 for the remainder of the forecast period starting in June, 2022. Predicting the impacts of the COVID-19 pandemic on future electric usage is difficult due to a lack of information and unknown factors in the medical community. The forecast electric consumption will vary according to the degree actual COVID-19 impacts differ from those modeled as part of this forecast. The individual components of the regression equation for the combined Commercial, Industrial, and Municipal classes are provided in Table 5.2-21.

¹⁵ A proxy employment indicator was developed from Woods & Poole data by combining employment for the farming, mining, manufacturing, information, finance, arts/entertainment, federal gov't, federal military, state and local gov't sectors.

**Table 5.2-21: Madisonville – Comm-Ind-Mun Regression Equation Detail**

Independent Variable (X_n)	Proxy Earnings	Total Employment (in thousands of jobs)	COVID-19	Year 2012	Year 2009	CDD/day ^1	Constant
Constants and Coefficients (β_n)	0.45	18.44	(81.11)	(27.40)	(43.84)	4.50	(271.47)

Commercial, Industrial, and Municipal Customer Count was forecast as a function of Madisonville State and Local Government Employment. The regression equation detail is shown in Table 5.2-22.

Table 5.2-22: Madisonville – Comm-Ind-Mun Customer Count Regression Equation Detail

State and Local Government Employment (in thousands)	Constant
129.50	1,047.50

- Large Industrial Customer: Monthly energy consumption was forecast using CDD with a 65.0-degree day cutoff. In addition, Manufacturing Employment data from Woods & Poole was used as an indicator of the local economy. Binary variables were also used for load prior to 2011, after 2012, after March 1, 2018, for the Winter season, and for the month of February. The individual components of the regression equation for this Large Industrial Customer are provided in Table 5.2-23.

Table 5.2-23: Madisonville – Large Industrial Customer Regression Equation Detail

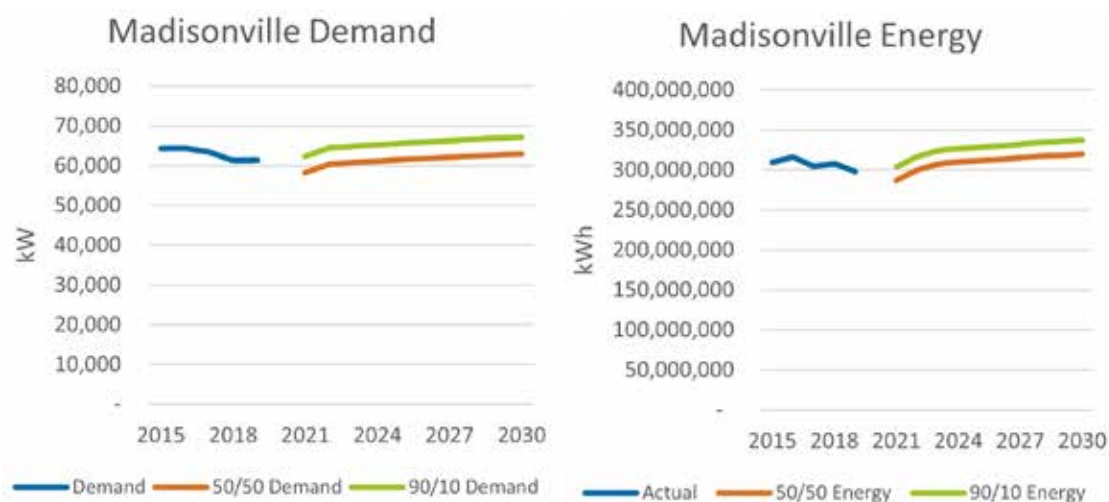
Independent Variable (X_n)	Manufacturing Employment (in thousands of jobs)	Post 3/1/2018	Month 2	Season Winter	Pre 2011	Post 2012	CDD/day ^1	Constant
Constants and Coefficients (β_n)	17,925.00	(24,486.89)	12,996.15	(11,138.99)	8,510.34	(11,283.67)	1,355.95	73,848.91

Large Industrial Customer Count was held constant at 1.

Table 5.2-24 and Figure 5.2-8 provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

**Table 5.2-24: Madisonville – Forecast (kW and kWh)**

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	64,086			308,671,226		
2016	64,159			315,465,679		
2017	63,269			303,901,065		
2018	61,073			307,676,795		
2019	61,290			297,690,150		
2020						
2021		58,071	62,114		286,414,290	303,330,810
2022		60,226	64,308		299,426,247	316,329,075
2023		60,611	64,711		306,272,164	323,083,932
2024		61,003	65,034		309,474,000	326,359,660
2025		61,349	65,474		310,701,118	327,704,286
2026		61,661	65,813		312,613,110	329,446,344
2027		61,942	66,056		314,468,020	331,287,286
2028		62,204	66,418		316,961,675	333,875,372
2029		62,537	66,765		317,824,055	334,826,649
2030		62,684	66,962		319,292,629	336,309,577
2015-2019 CAGR	(0.89%)			(0.72%)		
2021-2030 CAGR		0.77%	0.75%		1.09%	1.04%

**Figure 5.2-8: Madisonville – Forecast Graph**

As the table and figure above demonstrate, the forecast projects an increase to Madisonville’s demand and energy sales over the forecast period. This increase results from movement in various economic and demographic variables forecast by Woods & Poole for Frankfort for each of the retail class forecasts over the 2020-2032 period, as summarized below:

- **Residential economic forecast:** Energy usage per customer per day is forecast to grow based on Woods & Poole’s forecast of 1.0% annual increase in Total Earnings for Madisonville from 2020-2032. Residential Customer Count is



forecast to grow with Woods & Poole's forecast for Total Population growth in Madisonville of 0.1% per year from 2020-2032 for Madisonville.

- Commercial, Industrial, and Municipal economic forecast: Usage per customer per day is forecast to grow based on combined forecasts from Woods & Poole for 0.3% increase per year for Total Employment and 0.7% increase per year for the proxy earnings indicator. Commercial, Industrial, and Municipal Customer Counts are forecast to decrease with Woods & Poole forecast of a -0.1% annual decline in State and Local Government Employment.
- Large Industrial Customer economic forecast: Usage per customer per day is forecast to decline based on Woods & Poole forecast of -0.5% annual change in Manufacturing Employment. Large Industrial Customer Count is assumed to stay constant at 1.



Paris, KY – Member System-Level Forecast

The regression equation used to forecast Paris's monthly energy and peak demand used both CDD and HDD, with a degree day cutoff of 62.4 and 59.7, respectively. In addition, a combined proxy for Earnings created from Woods & Poole¹⁶ data is used as an indicator of the local economy as it relates to electric consumption. The individual components of the regression equation and the coefficients for each independent variable are provided in Table 5.2-25.

Table 5.2-25: Paris – Regression Equation Detail

Independent Variable (X_n)	Earnings Composite (in millions of 2012 dollars)	HDD/day $\wedge_1$	CDD/day $\wedge_1$	Constant
Constants and Coefficients (β_n)	215.45	4,339.71	6,249.86	66,622.00

Table 5.2-26 and Figure 5.2-9 provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

Table 5.2-26: Paris – Forecast (kW and kWh)

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	17,542			63,747,145		
2016	14,386			64,521,483		
2017	13,327			58,172,216		
2018	15,671			63,348,927		
2019	15,517			62,071,878		
2020						
2021		14,315	16,835		60,560,130	68,481,682
2022		14,340	16,878		60,666,246	68,523,308
2023		14,368	16,888		60,769,199	68,646,233
2024		14,372	16,890		60,951,790	68,827,503
2025		14,387	16,913		60,954,384	68,830,938
2026		14,409	16,939		61,038,816	68,924,356
2027		14,397	16,944		61,087,512	68,976,823
2028		14,431	16,949		61,298,505	69,184,390
2029		14,437	16,990		61,258,926	69,134,591
2030		14,456	16,995		61,344,601	69,220,861
2015-2019 CAGR	(2.42%)			(0.53%)		
2021-2030 CAGR		0.10%	0.09%		0.13%	0.11%

¹⁶ A proxy earnings indicator was developed from Woods & Poole data by combining data for the manufacturing, wholesale trade, transportation, information, education, and arts/entertainment sectors.

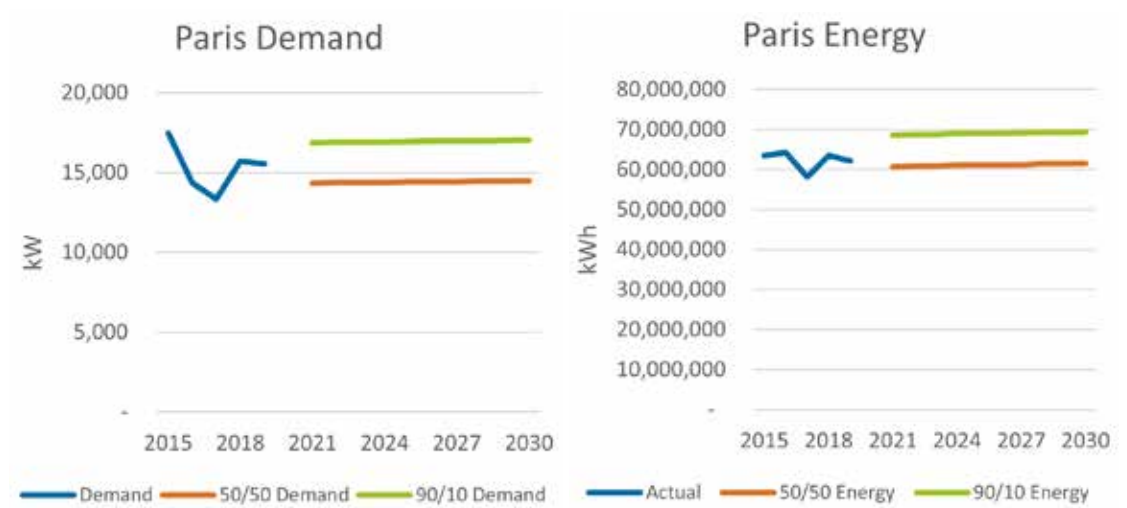


Figure 5.2-9: Paris – Forecast Graph

As the table and figure above demonstrate, the forecast projects an increase to Paris’s demand and energy sales over the forecast period. This increase results from growth in the proxy earnings indicator derived from Woods & Poole’s economic data, which is forecast to grow at 0.8% per year in Bourbon County between 2020-2032.



Providence, KY – Member System-Level Forecast

The regression equation used to forecast Providence's monthly energy and peak demand utilized both CDD and HDD, with a degree day cutoff of 66.3 and 48.5, respectively. In addition, a combined proxy for Earnings is used from Woods & Poole data as an indicator of the local economy as it relates to electric consumption, and binary variables are used for load after 2017 and for load occurring in the months of April and May. The individual components of the regression equation and the coefficients for each independent variable are provided in the Table 5.2-27.

Table 5.2-27: Providence – Regression Forecast Detail

Independent Variable (X_n)	Employment Proxy (in thousands of jobs)	Post 2017	Month 5	Month 4	HDD/day $\wedge_1$	CDD/day $\wedge_1$	Constant
Constants and Coefficients (β_n)	15,224.05	(7,771.23)	(5,295.43)	(4,065.67)	1,584.58	3,382.86	20,789.44

Table 5.2-28 and Figure 5.2-10 provide the most recent 5 years of actual demand and energy, as well as the 50/50 and 90/10 forecast for demand and energy through 2030.

Table 5.2-28: Providence – Forecast (kW and kWh)

Year	Demand	50/50 Demand	90/10 Demand	Energy	50/50 Energy	90/10 Energy
2015	6,817			30,971,367		
2016	6,886			30,140,268		
2017	6,815			29,413,903		
2018	6,635			29,737,622		
2019	6,383			27,045,696		
2020						
2021		6,868	7,980		27,504,247	31,530,713
2022		6,822	7,948		27,324,489	31,362,210
2023		6,828	7,976		27,320,322	31,364,344
2024		6,829	7,973		27,412,945	31,449,914
2025		6,832	7,959		27,338,954	31,373,142
2026		6,825	7,935		27,316,302	31,302,891
2027		6,817	7,934		27,256,560	31,282,127
2028		6,813	7,942		27,272,083	31,337,813
2029		6,817	7,966		27,216,515	31,274,588
2030		6,797	7,925		27,196,279	31,196,197
2015-2019 CAGR	(1.31%)			(2.67%)		
2021-2030 CAGR		(0.10%)	(0.07%)		(0.11%)	(0.11%)

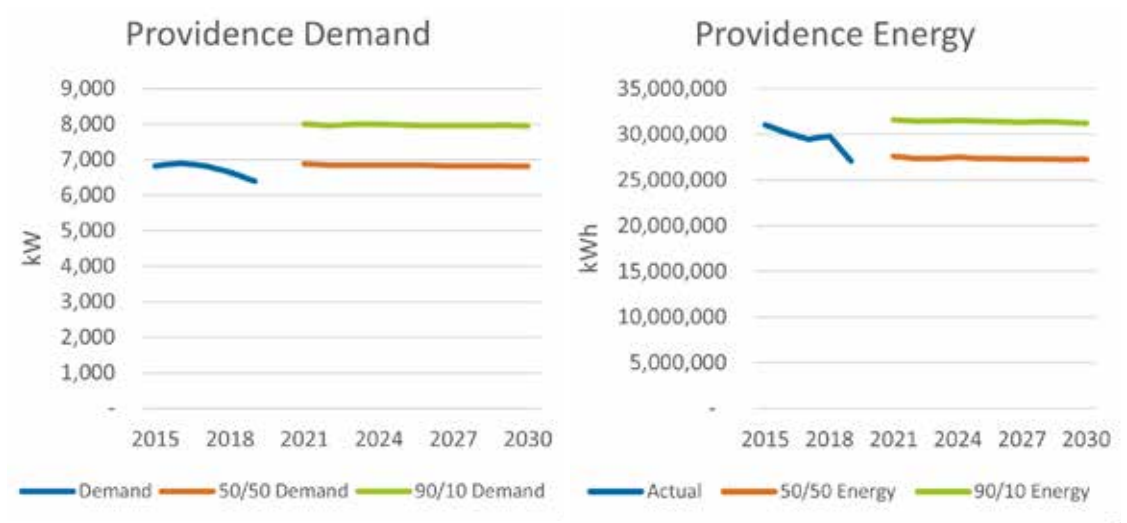


Figure 5.2-10: Providence – Forecast Graph

As the table and figure above demonstrate, the forecast projects a decrease to Providence’s demand and energy sales over the forecast period. This decrease results from a decrease in the proxy employment indicator derived from Woods & Poole’s economic data, which is forecast to decrease at -0.2% per year in Webster County between 2020-2032.



5.3 KYMEA Combined Member Forecasts

To prepare a forecast for all KYMEA member IRP2020 participants and for the AR Group, the forecast combined the member-level forecasts prepared for MOD-032 and then applied a three-year average historical diversity factor by month to calculate the coincident peak from the summed member non-coincident peaks. In each of the following subsections, the forecast presents the results of this combined forecast for the AR Group and for all KYMEA IRP2020 participants.

As described above, all load information presented herein is grossed up to generation voltage by applying a 1.02048 loss factor to load at transmission voltage. Further, 2021 is the first forecast year for MOD-032 and 2020 is a partial actual year; thus 2020 is blank in all forecasts.

AR Group – 50/50 and 90/10 Results

Table 5.3-1 provides the summary results for annual demand actuals for 2015-2019 and the 50/50 and 90/10 forecast results through 2030 for both summed NCP and for the combined CP of the AR Group.

Table 5.3-1: AR Group – Summed NCP and CP Annual Demand Actuals and Forecast Results

Year	AR Group Summed NCP (kW)			AR Group CP (kW)		
	Actuals	Forecast 50/50	Forecast 90/10	Actuals	Forecast 50/50	Forecast 90/10
2015	269,379			265,162		
2016	268,916			264,079		
2017	260,552			258,076		
2018	258,678			257,459		
2019	260,934			258,993		
2020						
2021		254,001	275,150		249,897	270,704
2022		258,480	280,138		254,303	275,611
2023		259,559	280,947		255,364	276,407
2024		260,537	282,106		256,327	277,547
2025		261,394	282,958		257,170	278,386
2026		262,175	284,033		257,938	279,443
2027		263,198	284,928		258,945	280,324
2028		263,950	286,067		259,685	281,444
2029		264,864	286,898		260,584	282,262
2030		265,388	287,515		261,100	282,869
2015-2019 CAGR	(0.64%)			(0.47%)		
2021-2030 CAGR		0.439%	0.441%		0.439%	0.441%

As the forecast indicates, the 50/50 and 90/10 forecasts for both the summed NCP and combined CP forecasts show a roughly 0.44% annual growth rate over the forecast period. This reverses the trend demonstrated in the compound annual growth rate (CAGR) during the 2015-2019 period. This forecast growth is a result of the economic data points discussed above as they are incorporated into each member forecast. Figure 5.3-1 provides a graphical representation of Table 5.3-1, presented above.

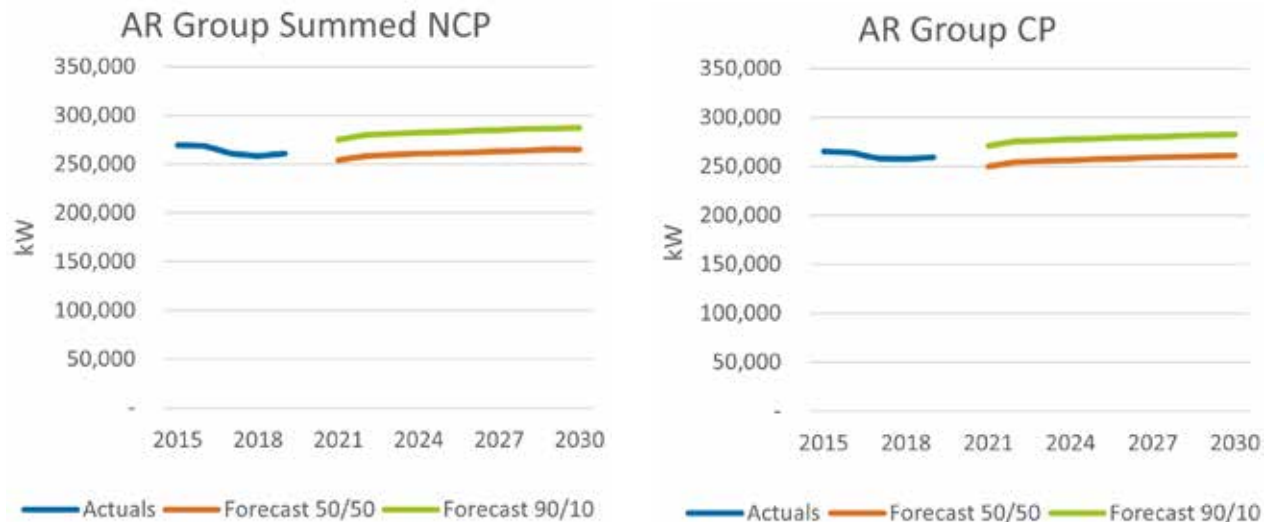


Figure 5.3-1: AR Group – Forecast Graph

As Table 5.3-1 and Figure 5.3-1 above show, the first years of the 50/50 forecast are below the peak KYMEA actually experienced in 2019, which was the last full year for which actual data is available. A portion of this difference in the lower peak demand in the forecast is driven by COVID-19 impacts forecast for KYMEA's largest members of Frankfort and Madisonville. To confirm the appropriateness of the starting point for the forecast, the forecast also conducted a weather normalization analysis on the AR Group's hourly system load between 2010 and 2020, a longest time period for which hourly load data for the combined AR Group is available.

The forecast performed a weather normalization analysis by first applying the Rank and Average method for determining normal weather. This approach involves ranking each hour of a given year in order of temperature and then taking an average over the first hottest hours, the second hottest hours, and so on. This results in a dataset of the average hottest temperatures through to the average coldest temperatures. These average temperatures are then applied to the year of interest aligning the average hottest temperature with the hottest of the year. The forecast then constructed a machine learning model to estimate hourly load as a function of descriptor variables including, but not limited to, temperature, cooling degrees, heating degrees, weekend indicators, and holiday indicators. Once the model is trained on the actual temperatures, the temperature profile is swapped out for the normalized weather profile and then the model is run again producing an estimate of weather normalized load. Weather normalized load typically shows a reduction compared to actuals when the actual temperature is above normal and vice versa an increase when the actual temperature is below normal.

The forecast found that the 2018 and 2019 peak events were largely the results of higher than average temperatures or weather that is more extreme than normal. In particular, the days leading up to the 2019 peak event saw a series of high temperatures, which drove the peak event. Based on the weather normalization analysis The forecast conducted, this series of high-temperature days produced CDD levels substantially higher than normal. Adjusting the actual load to reflect circumstances likely to have occurred under normal weather produces a lower peak event in 2019, more in line with our 50/50 forecast, as Figure 5.3-2 demonstrates.

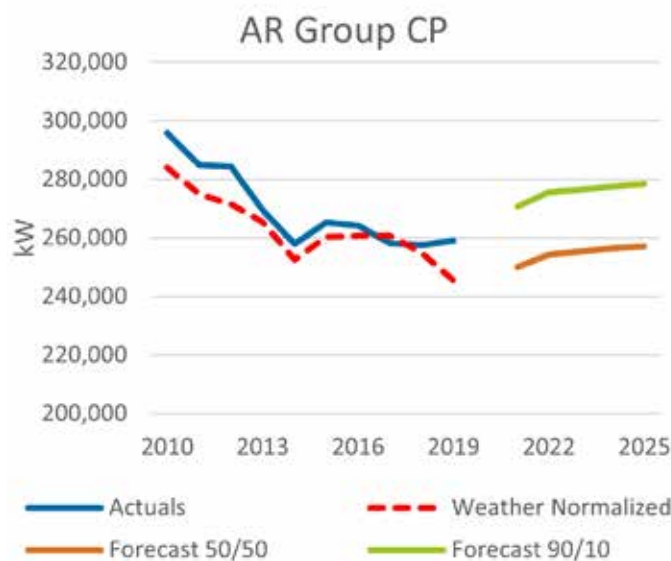


Figure 5.3-2: AR Group – Forecast Graph with Weather Normalized Actuals

Table 5.3-2 provides summary results for annual energy sales for actuals from 2015-2019 and for the forecast period through 2030 for the AR Group.

Table 5.3-2: AR Group – Annual and Forecast Energy Sales

Year	AR Group Summed Energy (MWh)		
	Actuals	Forecast 50/50	Forecast 90/10
2015	1,321,157		
2016	1,339,171		
2017	1,279,914		
2018	1,317,688		
2019	1,273,797		
2020			
2021		1,253,030	1,341,513
2022		1,281,483	1,370,761
2023		1,294,220	1,383,449
2024		1,303,280	1,393,260
2025		1,305,146	1,395,800
2026		1,309,990	1,400,868
2027		1,314,962	1,406,539
2028		1,322,595	1,415,112
2029		1,324,063	1,416,832
2030		1,328,404	1,421,542
2015-2019 CAGR	(0.73%)		
2021-2030 CAGR		0.59%	0.58%



Like the combined demand forecasts presented above, the energy forecast demonstrates a positive growth rate in the 2020-2030 CAGR. Figure 5.3-3 provides a graphical representation of Table 5.3-2 presented above.

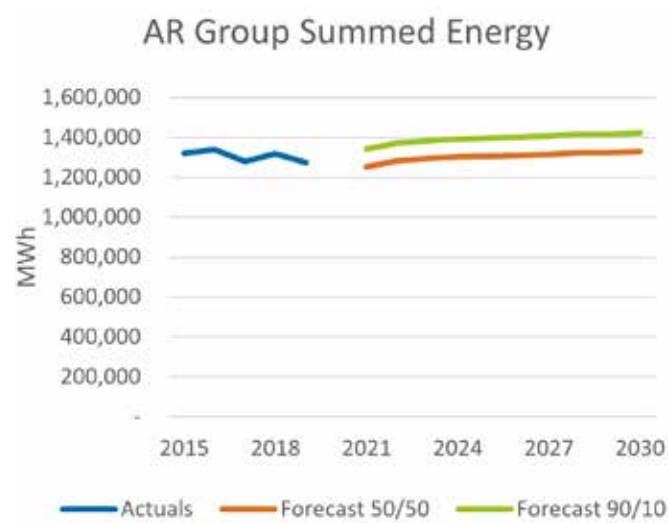


Figure 5.3-3: AR Group – Forecast Graph



IRP2020 Participants – 50/50 and 90/10 Results

Table 5.3-3 provides the summary results for annual demand actuals for 2015-2019 and the 50/50 and 90/10 forecast results through 2030 for both summed NCP and for the combined CP for all KYMEA IRP participants.

Table 5.3-3: IRP Participants – Summed NCP and CP Annual Demand Actuals and Forecast Results

Year	IRP Participants Summed NCP (kW)			IRP Participants CP (kW)		
	Actuals	Forecast 50/50	Forecast 90/10	Actuals	Forecast 50/50	Forecast 90/10
2015	308,115			313,604		
2016	292,875			299,434		
2017	287,527			290,345		
2018	286,952			289,132		
2019	287,981			291,408		
2020						
2021		278,571	302,096		283,660	307,614
2022		283,312	307,306		288,487	312,919
2023		284,342	308,126		289,537	313,755
2024		285,338	309,273		290,551	314,923
2025		286,181	310,079		291,409	315,744
2026		286,929	311,131		292,170	316,814
2027		287,957	312,005		293,218	317,704
2028		288,693	313,176		293,967	318,898
2029		289,584	313,958		294,874	319,694
2030		290,122	314,599		295,422	320,346
2015-2019 CAGR	(1.34%)			(1.46%)		
2021-2030 CAGR		0.407%	0.406%		0.407%	0.406%

Similar to the forecast results for the AR Group, the 50/50 and 90/10 forecasts for both the summed NCP and combined CP forecasts show a compound annual growth rate of roughly 0.4% over the forecast period. This forecast growth is a result of the economic and/or demographic data points discussed above incorporated into each member forecast. Figure 5.3-4 provides a graphical representation of Table 5.3-3, presented above.

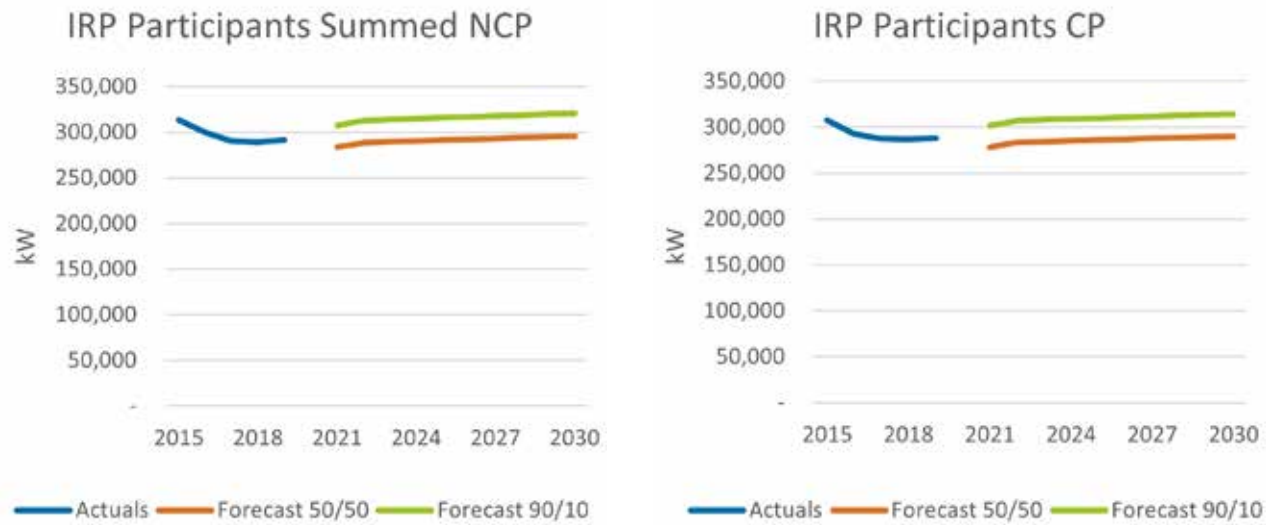


Figure 5.3-4: IRP Participant Forecast Graph

Table 5.3-4 provides summary results for annual energy sales for actuals from 2015-2019 and for the forecast period through 2030 for all KYMEA IRP participants.

Table 5.3-4: IRP Participants – Annual and Forecast Energy Sales

Year	IRP Participants Summed Energy (MWh)		
	Actuals	Forecast 50/50	Forecast 90/10
2015	1,478,366		
2016	1,498,650		
2017	1,432,022		
2018	1,483,431		
2019	1,434,864		
2020			
2021		1,408,352	1,511,940
2022		1,438,704	1,543,064
2023		1,452,300	1,556,629
2024		1,461,760	1,566,897
2025		1,463,281	1,569,089
2026		1,468,145	1,574,119
2027		1,473,140	1,579,780
2028		1,481,123	1,588,745
2029		1,482,253	1,590,179
2030		1,486,622	1,594,893
2015-2019 CAGR	(0.60%)		
2021-2030 CAGR		0.54%	0.54%



Like the combined demand forecasts presented above, the forecast period demonstrates a positive growth rate in the 2020-2030 CAGR. Figure 5.3-5 provides a graphical representation of Table 5.3-4 presented above.

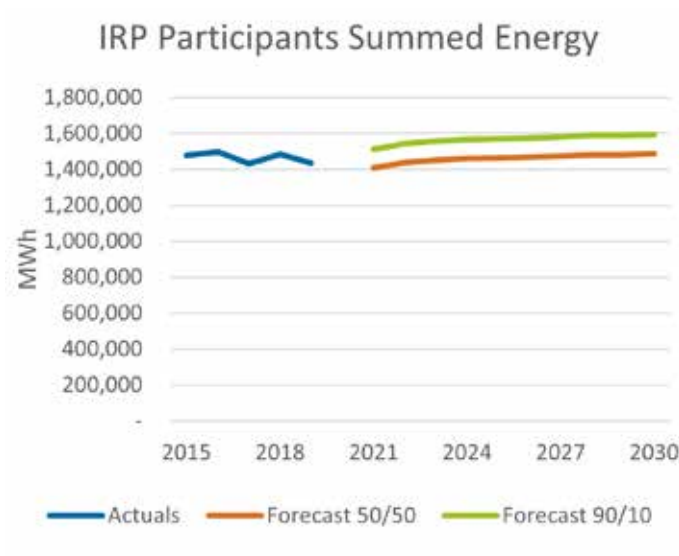


Figure 5.3-5: IRP Participant Summed Energy Forecast Graph



5.4 COVID-19 Pandemic

COVID-19 Load Impact

At the time the IRP2020 report was being prepared, the world was deeply immersed in the COVID-19 global pandemic. Prior to the pandemic, the U.S. economy was doing very well. Unemployment was at a 50-year low and inflation was below the Fed's target of 2.0%. Because the U.S. closed a significant portion of the U.S. economy, real GDP growth (i.e., the percent increase/decrease in economic growth compared to one year prior, net of inflation), fell during the second quarter by an astounding 31.40% and the unemployment rate skyrocketed to 14.8%. These are numbers not seen since the Great Recession, as represented in the Figure 5.4-1 unemployment rate graph.

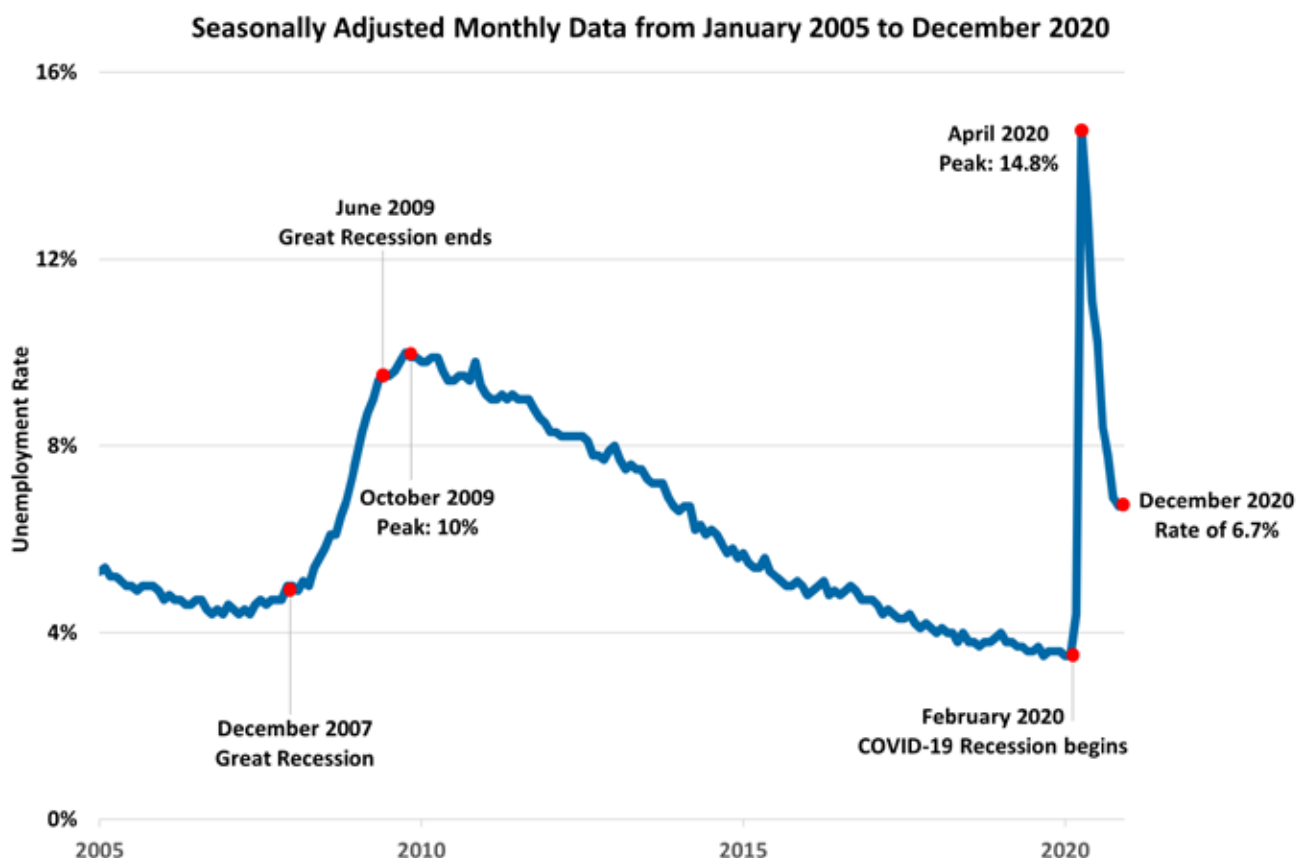


Figure 5.4-1: Unemployment Rate During COVID-19 Pandemic¹⁷

During the pandemic, a balance was drawn between the health of individuals and the health of the economy. In Kentucky, there has been an ebb and flow of the temporary closing of businesses and schools to slow the spread of the virus coupled with the reopening of these facilities to limit the devastating impact on the economy. The temporary closing of businesses and schools and the shift to remote offices has had a significant impact on KYMEA's loads.

For fiscal year 2021 (July 2020 through June 2021), KYMEA's loads are expected to be approximately 10% under budget. Figure 5.4-2 illustrates FY2021's projected shortfall using six months of actual data (July 2020 – December 2020) and six months of projected data (January 2021 – June 2021).

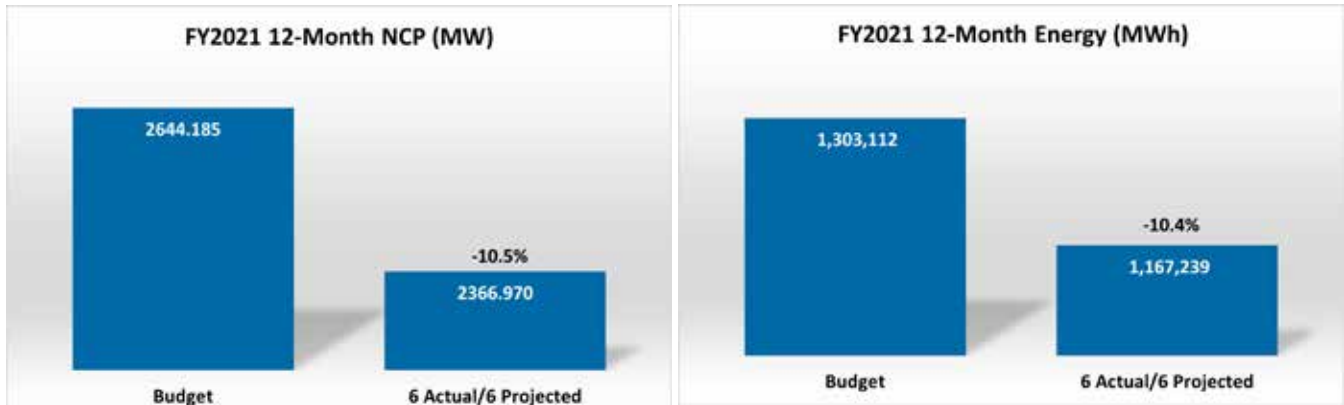


Figure 5.4-2: COVID-19 Load Impact – FY 2021 12-Month NCP and Energy

COVID-19 Load Destruction and Recovery

It is unclear how much of the lost load KYMEA experienced during the pandemic is going to be permanent load destruction. In December 2020, the U.S. Food and Drug Administration issued an emergency use authorization for two COVID-19 vaccines. Additional vaccines are under development at the time this report was written. States have begun distributing the vaccine; however, herd immunity is not expected to occur until sometime in 2022. Using the herd immunity estimate as a guide, KYMEA is projecting its load to recover by April 2022. KYMEA does not expect significant load destruction; however, it is likely that home offices and working remotely will become more prevalent which will likely cause a shift in usage behavior. KYMEA has projected load recovery shown in Figure 5.4-3.

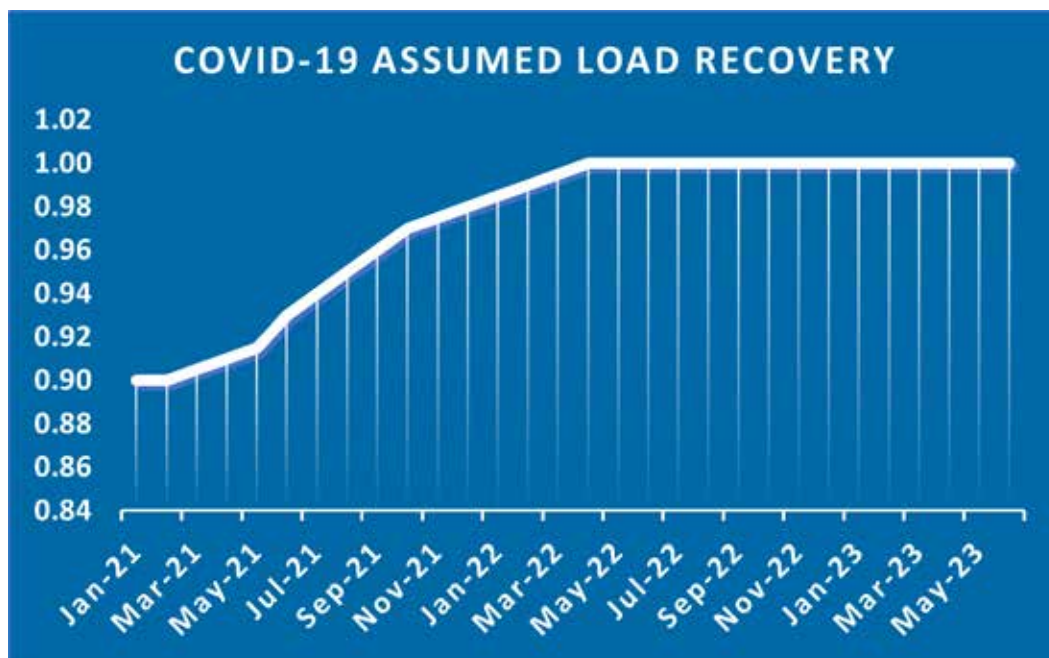


Figure 5.4-3: COVID-19 Assumed Load Recovery



5.5 Hourly Load Shapes

As described in Section 5.2, a load forecast of monthly peaks and energies was created for each member. Using a historical hourly load shape by member, the monthly peaks and energies are sculpted into an hourly load forecast. Shown in Figure 5.5-1, is the coincident transmission-level hourly load forecast for the KYMEA All Requirements Project members.

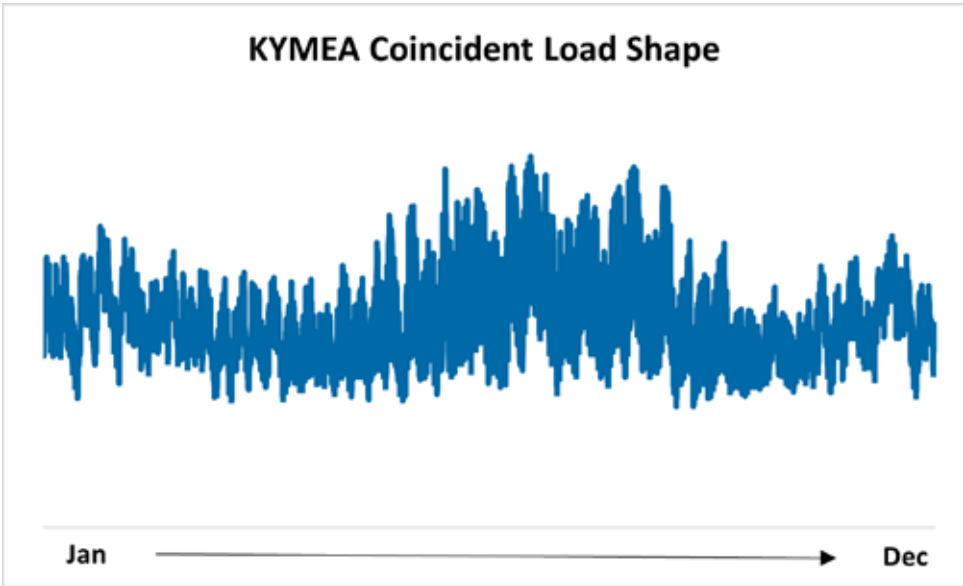


Figure 5.5-1: KYMEA AR Project Coincident Load Shape



5.6 Annual Load Forecasts

The forecast of KYMEA's 1-in-10 peak demand, 1-in-10 net peak demand, and its expected 50/50 peak demand and annual energy requirements by planning year (June-May) is shown in Table 5.6-1. The resulting long-term average growth rate is 0.27% for the peak demand and 0.56% for the annual energy. Over time, the differing growth rates produce a higher load factor. The forecast post-2030 data was extrapolated from the 10-year NERC MOD32 data. The load is reported at a generation level meaning a loss factor of 1.02048 is applied to the load located in the LKE transmission area.

Table 5.6-1: KYMEA Annual Load Forecast (MW and MWh)

	1-in-10 Coincident Peak Demand			Expected Peak and Energy		
	Summer Peak	Summer Net Peak	Winter Peak	Peak	Energy	Load Factor
PY22/23	279	246	231	257	1,281,078	56.9%
PY23/24	279	246	232	258	1,289,623	57.0%
PY24/25	280	247	232	259	1,292,058	56.9%
PY25/26	281	247	233	260	1,296,772	56.9%
PY26/27	282	247	234	261	1,301,537	57.0%
PY27/28	283	248	235	262	1,309,458	57.1%
PY28/29	284	250	235	263	1,310,721	57.0%
PY29/30	285	252	237	263	1,315,245	57.0%
PY30/31	286	251	237	264	1,319,382	57.0%
PY31/32	287	252	238	265	1,327,005	57.2%
PY32/33	287	253	238	265	1,336,232	57.5%
PY33/34	288	254	239	266	1,345,819	57.8%
PY34/35	289	256	240	267	1,355,505	58.0%
PY35/36	290	258	242	267	1,365,261	58.3%
PY36/37	291	259	242	268	1,375,091	58.6%
PY37/38	291	260	243	268	1,384,995	58.9%
PY38/39	292	261	243	269	1,394,974	59.2%
PY39/40	293	262	244	269	1,405,027	59.5%
PY40/41	294	265	245	270	1,415,158	59.8%
PY41/42	295	267	246	271	1,425,364	60.1%
CAGR %				0.27%	0.56%	

The lower long-term peak growth rate of 0.27% is driven by expected efficiency improvements in the air conditioning seasonal energy efficiency ratio (SEER) and other peak reduction technology advancements.



Summer Peak and Net Peak

The majority of KYMEA’s load (98.5%) is not in an open and competitive power market, but rather resides inside the LKE transmission area. As such, KYMEA must plan its system to not produce more energy than can be used for its native load requirements. In the absence of storage, KYMEA’s solar generation inside LG&E/KU is limited to approximately 105 MW. Quantities greater than 105 MW produce excess generation which KYMEA cannot sell since there is not a power market inside the LG&E/KU BA. In order to sell surplus energy to markets outside the LG&E/KU BA, KYMEA would need to purchase point-to-point transmission service on LKE, which would be subject to both availability and incremental costs. Further, KYMEA cannot dump the excess generation into the LG&E/KU system, as that violates the LG&E/KU imbalance energy tariff.

Assuming a maximum solar size of 105 MW, KYMEA calculates both its Summer Peak and its Summer Net Peak. The net load, or duck curve as coined by the California ISO (CAISO), refers to the hourly load after netting solar generation against the native load requirements. The net load produces a shape that resembles a duck as shown in Figure 5.6-1. The importance of calculating the net peak is to ensure KYMEA has adequate power and transmission resources to meet a demand that occurs later in the evening after the sun has set. Whereas the native load peak is likely to occur in July or early August between 2 pm and 4 pm, the net peak is more likely to occur in late August or early September between 6 pm and 9 pm, when the solar irradiance is diminished earlier in the evening hours due to the tilt of the earth relative to the position of the sun.

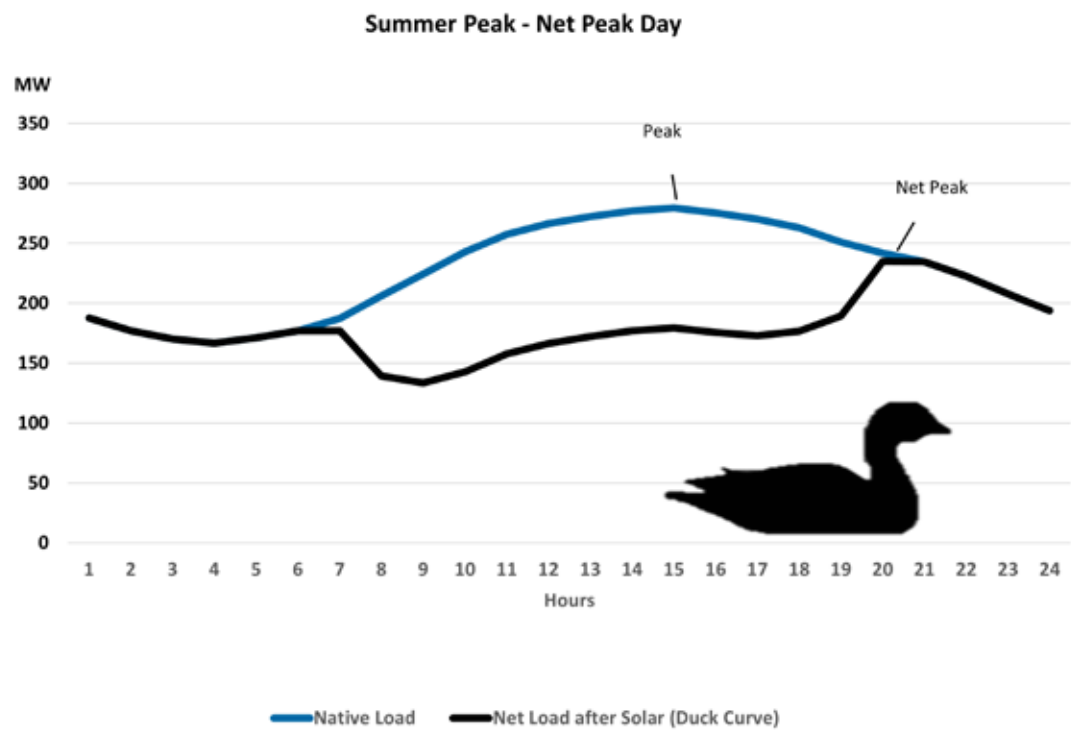
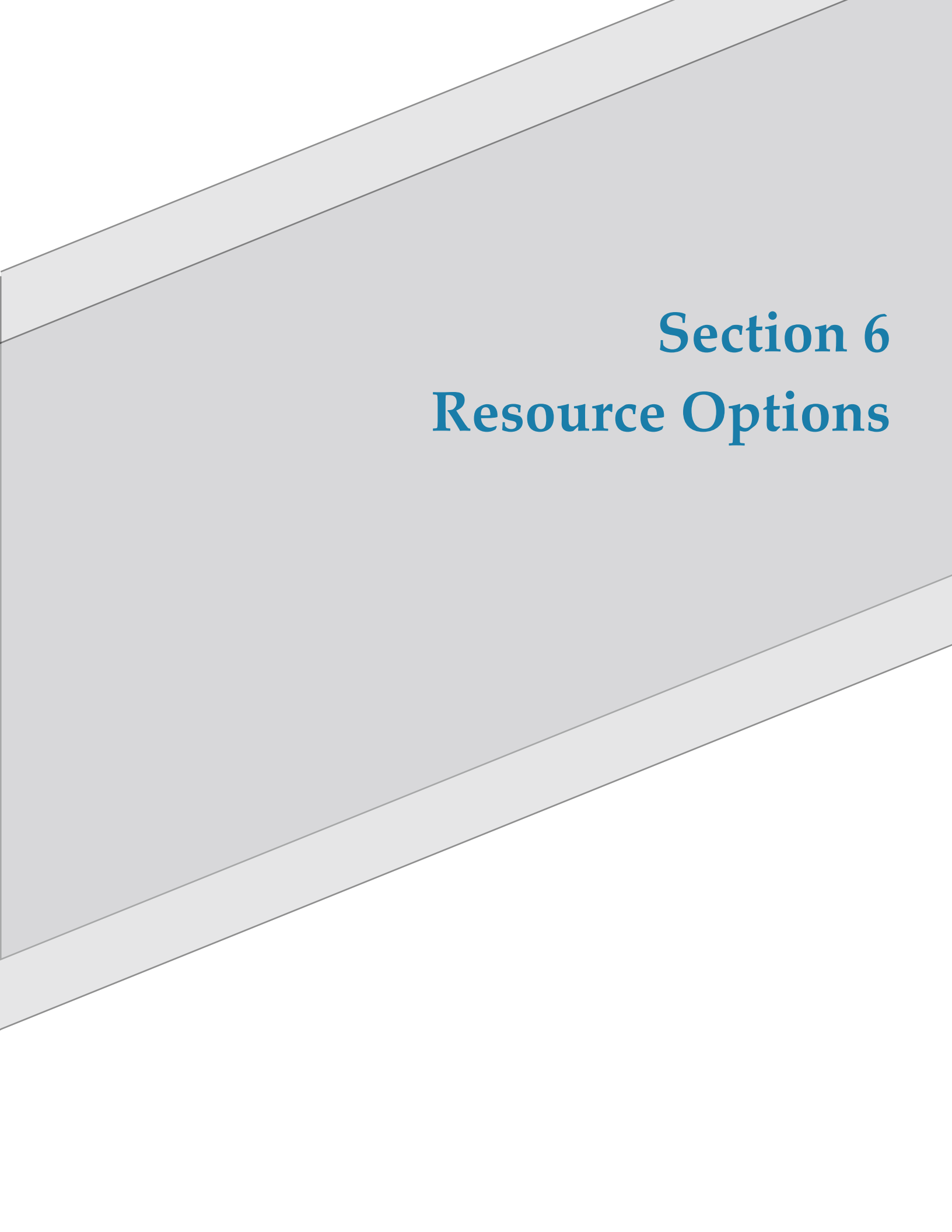


Figure 5.6-1: Summer Peak and Net Peak Day

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Section 6

Resource Options

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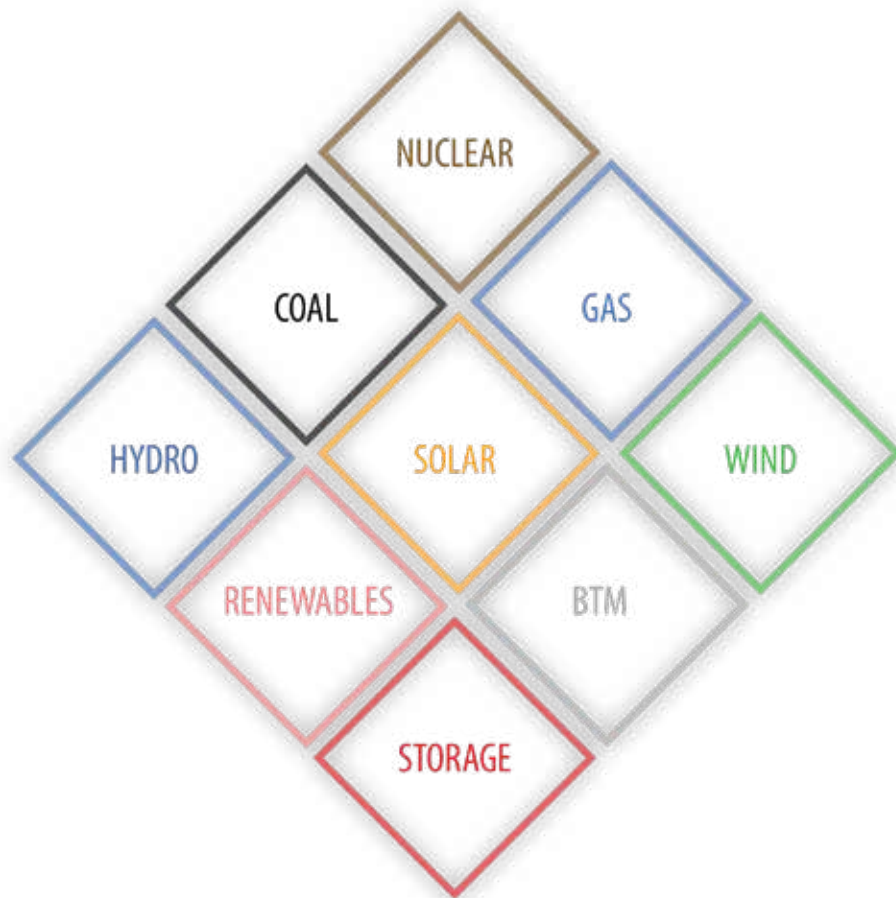


6. RESOURCE OPTIONS

KYMEA researched various types of supply-side and demand-side resources. The purpose of the research was to identify a wide range of resource options and determine which resources would be available to KYMEA, recognizing that some may not be practically accessible. For example, geothermal energy is located exclusively in the western continental United States, Alaska, and Hawaii and is not available in Kentucky or the surrounding states.

For KYMEA's near-term resource additions, as described in Section 13 (Plan Development), an indicative request for proposals (RFP2020) was issued in August 2020, to identify available resource options. Many of the resource options described in this section were not included in the portfolio analysis but are discussed here as potential resource options in the future. The resources may be used when developing expansion plans for Kentucky, MISO, and other markets, and therefore may have an indirect effect on the KYMEA power supply plan.

RESOURCE OPTIONS





6.1 Analysis of U.S. & Kentucky Resources

2020 U.S. Electricity Generation

In 2020, approximately 4 trillion kWh of electricity was generated in the United States. Fossil fuels accounted for 60.3% of energy production, with natural gas topping the list at 40.3% of all generation. Coal-fired plants provided most of the remainder of the fossil fuel energy by contributing 19.3%. Nuclear energy made up another 19.7% of the U.S. total. Renewable resources as a whole contributed 19.8% of electricity generation, with most coming from wind (8.4%), hydropower (7.3%), and solar (2.3%). Shown in Table 6.1-1 is a comprehensive list of energy production by fuel source.

Table 6.1-1: U.S. Utility-Scale Electricity Generation by Source, Amount, and Share of Total in 2020¹⁸

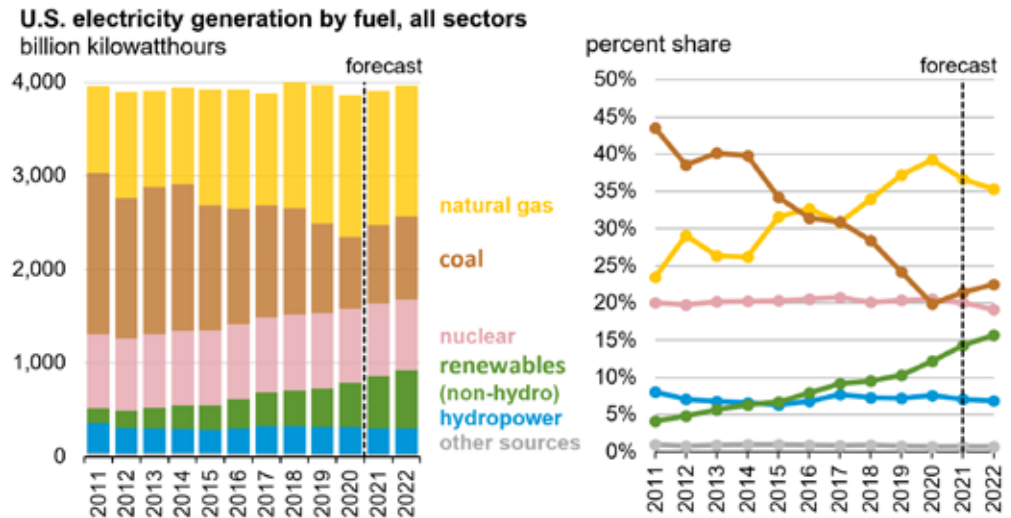
U.S. Utility-Scale Electricity Generation by Source, Amount, and Share of Total in 2020		
Energy Source	Billion kWh	Share of Total
Total- all sources	4,009	
Fossil Fuels (total)	2,419	60.3%
Natural Gas	1,617	40.3%
Coal	774	19.3%
Petroleum (total)	17	0.4%
Petroleum Liquids	10	0.2%
Petroleum Coke	8	0.2%
Other Gases	11	0.3%
Nuclear	790	19.7%
Renewables (total)	792	19.8%
Wind	338	8.4%
Hydropower	291	7.3%
Solar (total)	91	2.3%
Photovoltaic	88	2.2%
Solar Thermal	3	0.1%
Biomass (total)	56	1.4%
Wood	37	0.9%
Landfill Gas	10	0.3%
Municipal Solid Waste	6	0.2%
Other Biomass Waste	2	0.1%
Geothermal	17	0.4%
Pumped Storage Hydropower	-5	-0.1%
Other Sources	13	0.3%

18

What is U.S. electricity generation by energy source? (2021, February). Retrieved April 21, 2021, from <https://www.eia.gov/tools/faqs/faq.php?id=427&t=3>



KYMEA reviewed all generating units in the U.S., which include planned retirements and additions. Figures 6.1-1 and 6.1-2 provide a look at those units.



Source: U.S. Energy Information Administration, Short-Term Energy Outlook, February 2021



Figure 6.1-1: U.S. Electricity Generation by Fuel, All Sectors¹⁹

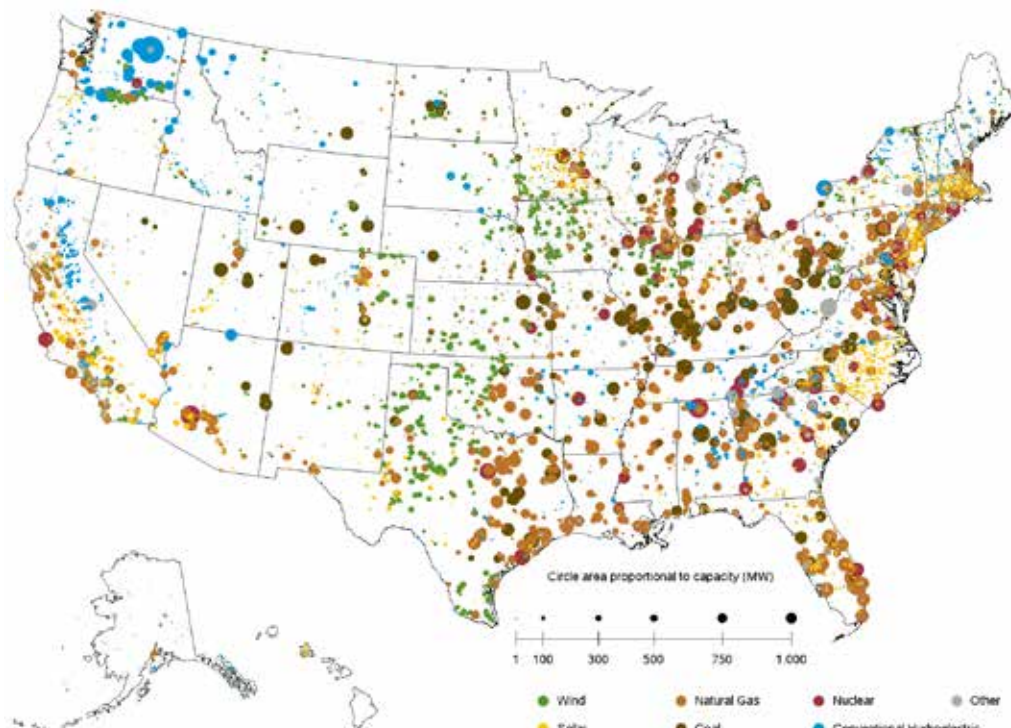


Figure 6.1-2: Operable Utility-Scale U.S. Generating Units as of November 2020



U.S. Additions

The U.S. Energy Information Administration (EIA) estimates that almost 40 gigawatts (GW) of new electric generating capacity will come online in 2021. As shown in Figure 6.1-3, utility-scale solar facilities comprise the largest portion (15.4 GW or 39%) of the new construction, with wind generation a close second at 12.2 GW (31%). Plants using natural gas as a fuel will add an additional 6.6 GW (16%) of capacity. Battery storage (4.3 GW or 11%) and nuclear (1.1 GW or 3%) make up the remainder of the 2021 new generation.

Most projects are concentrated within five states: California, Texas, North Carolina, Oklahoma, and Virginia. It is important to note that capacity ratings for solar and wind resources depict the nameplate capacity for these resources; firm capacity available to serve peak demands will typically be measured at a lower value, indicative of the temporal and intermittent nature of these resources.

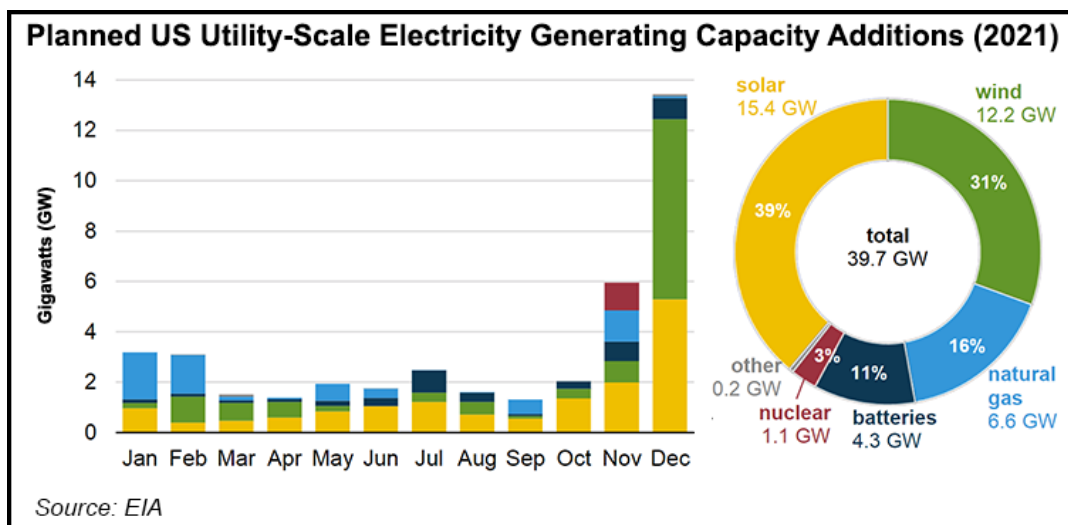


Figure 6.1-3: Planned U.S. Utility-Scale Electric Generating Capacity Additions (2021)²⁰

²⁰ Renewables account for most new U.S. electricity generating capacity in 2021. (2021, January 11). Retrieved April 21, 2021, from <https://www.eia.gov/todayinenergy/detail.php?id=46416>



Solar Photovoltaics. Developers and plant owners expect the addition of utility-scale solar capacity to set a new record by adding 15.4 GW of capacity to the grid in 2021.

Wind. The largest wind project coming online in 2021 will be the 999 MW Traverse wind farm in Oklahoma.

Offshore Wind. The 12 MW Coastal Virginia Offshore Wind (CVOW) pilot project, located 27 miles off the coast of Virginia Beach, is scheduled to start commercial operation in early 2021.

Natural Gas. For 2021, planned natural gas capacity additions are reported at 6.6 GW. Combined-cycle generators account for 3.9 GW, and combustion-turbine generators account for 2.6 GW. More than 70% of these planned additions are in Texas, Ohio, and Pennsylvania.

Battery Storage. The world's largest solar-powered battery (409 MW/900-MWh 2.2-hour battery) is under construction at Manatee Solar Energy Center in Florida; the battery is scheduled to be operational by late 2021.

Nuclear. Plant Vogtle units 3 & 4 are in Waynesboro, Georgia. As of October 2020, unit 3 construction is approximately 96% complete, with the total Vogtle 3 & 4 expansion project approximately 88% complete. Georgia Power continues to expect to meet the November 2021 and November 2022 regulatory-approved in-service dates for Units 3 and 4, respectively.

Figure 6.1-4 illustrates the projected U.S. electric generating capacity additions for 2021.

U.S. electric generating capacity additions (2021)

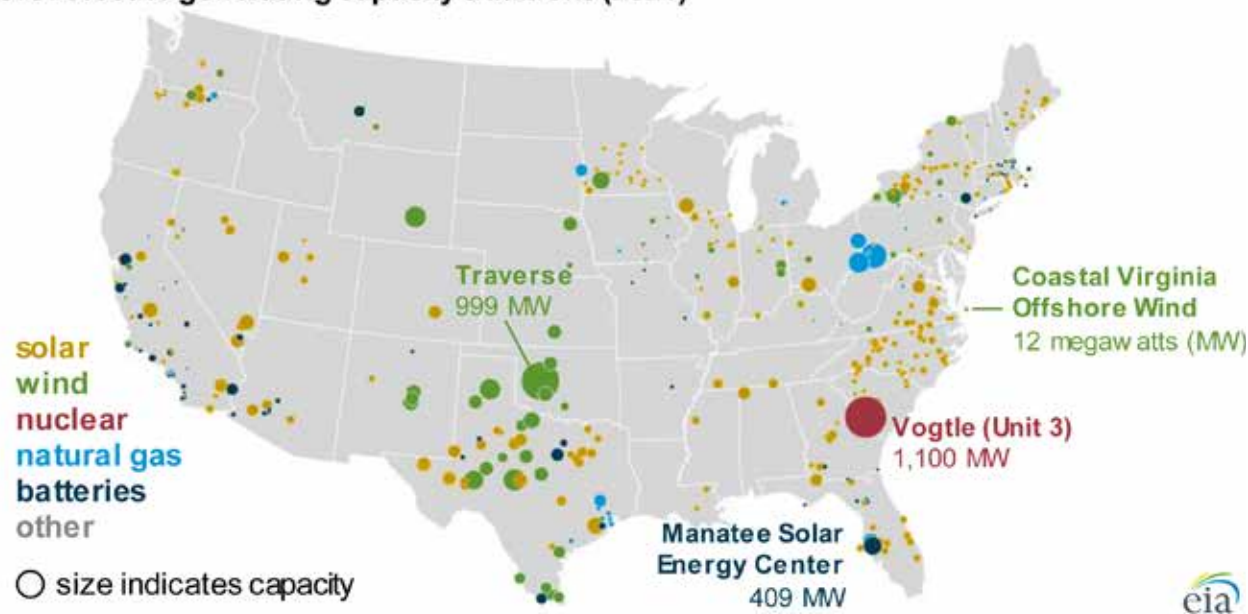


Figure 6.1-4: Map of U.S. Electric Generating Capacity Additions (2021)²¹

21 Renewables account for most new U.S. electricity generating capacity in 2021. (2021, January 11). Retrieved April 21, 2021, from <https://www.eia.gov/todayinenergy/detail.php?id=46416>



Analysis of Kentucky Resources

The Commonwealth of Kentucky ranks 5th in states with estimated coal reserves and 5th in coal production. It is therefore not surprising that Kentucky relies heavily on coal as its primary electricity generation source. While coal-fired plants provided 73% of Kentucky electricity production in 2019, the 4th largest share in the nation, this percentage has decreased in the last decade as coal-powered plants were converted to use natural gas or retired completely. Natural gas electricity production represented 20% of Kentucky's supply in 2019. Hydropower makes up the majority of the remaining generation, along with very small contributions from solar, biomass, and petroleum.

Figure 6.1-5 illustrates the planned and operating power plants in Kentucky as of May 21, 2021.

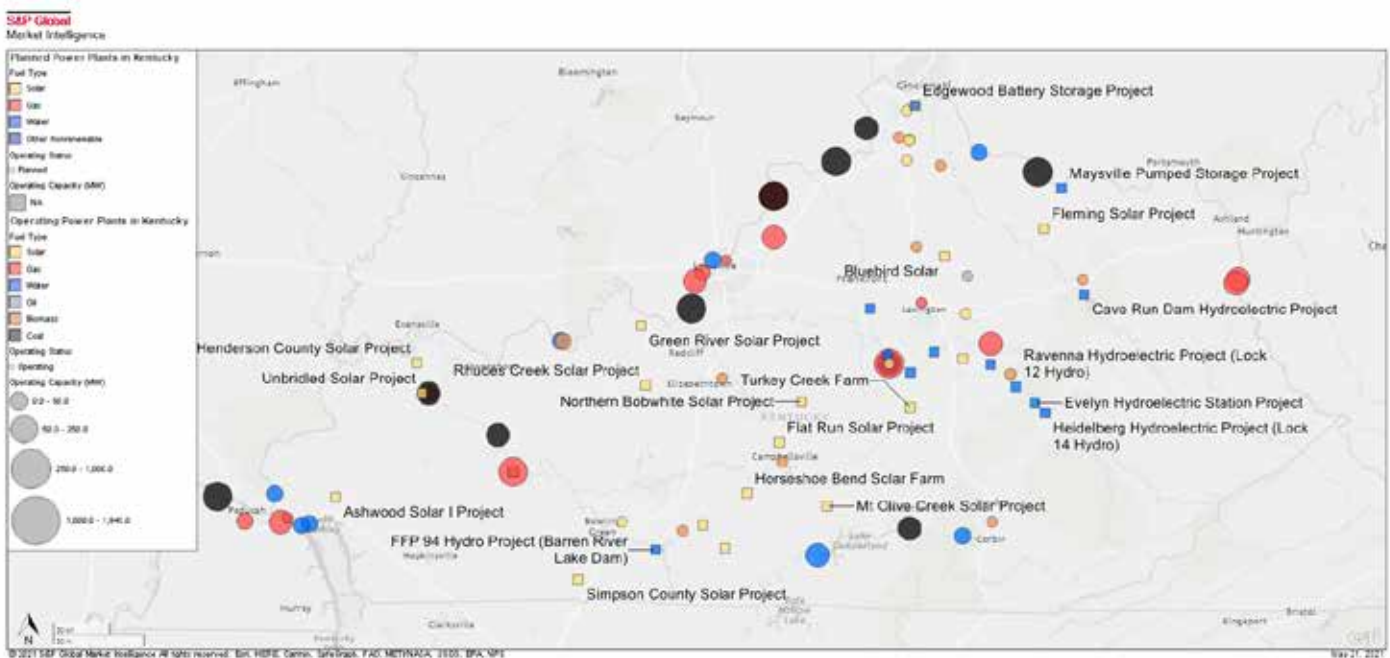


Figure 6.1-5: Power Plants in Kentucky²²



6.2 Coal Generation

- Illinois Power Marketing Company and KYMEA entered into a three-year power supply contract for 100 MW of capacity and energy from three units of the Joppa Power Station. Joppa Power Station, located in southern Illinois, is a 1,002 MW subcritical coal-fired power plant consisting of six generating units. The first unit reached commercial operation in August 1953, and the newest unit reached commercial operation in August 1955. Service under the contract commenced on June 1, 2019.
- Big Rivers Electric Corporation and KYMEA entered into a ten-year power supply contract for firm capacity and energy. The contract entitles KYMEA to 100 MW of base capacity, plus associated planning reserves, sourced from the Big Rivers generating fleet. Service under the contract commenced on May 1, 2019. D.B. Wilson power plant, located in western Kentucky, is a single-unit, 417 MW subcritical coal-fired steam power plant. The plant reached commercial operation in September 1984.



Illinois Power Marketing Company - Joppa Power Station

Location: Metropolis, IL

Type: Subcritical coal-fired steam plant

History: The first unit reached commercial operation in August 1953, and the newest unit reached commercial operation in August 1955.

PPA Expiration: May 31, 2022

Capacity: 100 MW



Big Rivers Electric Corporation - D.B. Wilson

Location: Centertown, & Sebree, KY

Type: Coal-fired steam plant

History: In 2015, Navigant recognized Wilson Station as the Runner-Up with the GKS Fossil Plant Operational Excellence Award.

PPA Expiration: May 31, 2029

Capacity: 100 MW

Overview

Coal came into use as a major energy source during the Industrial Revolution and has been the mainstay of the electric generating fleet in the United States ever since. In 2005, electricity generation from coal accounted for over half of U.S. power generation; however, these plants have been retiring in record numbers over the past several years. The future of coal is questionable. By 2020, due to regulatory burdens, financial incentives to switch fuels, declining capital costs for solar PV and wind, and low natural gas prices due to the abundance of shale natural gas, coal slipped in rank to the second-largest fuel source for U.S. electricity production – approximately 20%. Coal's contribution to the electricity generation mix in 2019 is somewhat higher in the MISO footprint (37.4%)²³ and Kentucky (73%) than in the rest of the U.S. In 2019, the PJM market's reliance on coal-fired generation was 23.8% and more closely reflects the U.S. as a whole. The EIA expects electric power generated with coal to increase slightly to 21% in 2021 and 22% in 2022; a result of rising natural gas prices.



Technologies

Most coal-fired power plants use steam turbines to produce electricity. A conveyor belt carries the mined coal to a pulverizer, where it is ground to the fineness of talcum powder. The powdered coal is then blown into a combustion chamber of a boiler, where it is burned at around 2,550°F. Surrounding the walls of the boiler room are pipes filled with water. Due to intense heat, the water vaporizes into superheated (2,000°F) high-pressure (1,000 psi) steam. The steam passes through a turbine connected to a generator. The incoming steam causes the turbine to rotate, creating a magnetic field inside wire coils in the generator. This pushes an electric current through the coils out of the power plant through transmission lines. After the steam passes through the turbine chamber, it is cooled down in cooling towers; and it again becomes part of the water/steam cycle.

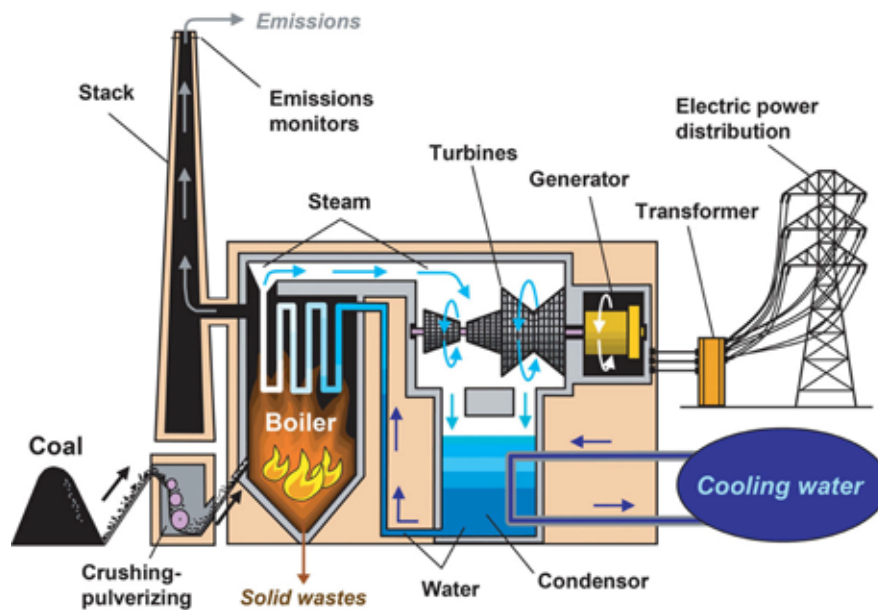


Figure 6.2-1: Illustration Coal-Fired Power Plant²⁴

24

Coal for electricity Generation, Kentucky Geological SURVEY, University of Kentucky. (n.d.). Retrieved April 21, 2021, from <https://www.uky.edu/KGS/coal/coal-for-elec.php>



Emissions Control

Several principal emissions result from coal combustion:

- Sulfur dioxide (SO₂), which may lead to acid rain and respiratory illnesses
- Nitrogen oxides (NO_x), which promote smog and respiratory illnesses
- Particulates, which add to smog, haze, and may cause respiratory illnesses and lung disease
- Carbon dioxide (CO₂), which is the primary greenhouse gas resulting from burning fossil fuels (coal, oil, and natural gas)
- Mercury and other heavy metals, which may contribute to both neurological and developmental damage in humans and other animals
- Fly ash and bottom ash, which are waste materials created when power plants burn coal

In the past, fly ash was released into the air through the smokestack; but current laws require most emissions of fly ash to be captured by pollution control devices. In the United States, fly ash and bottom ash are generally stored near power plants or placed in landfills.

Environmental Constraints

Since 1970, while coal consumption has risen 146%, U.S. emissions from coal have been reduced 82%. The Clean Air Act (CAA) and the Clean Water Act (CWA) require industries to reduce pollutants released into the air and water. In response, coal power generation plants have adopted several ways to reduce sulfur and other impurities from coal. The industry has developed more effective ways of cleaning coal after it is mined, and some coal consumers use low sulfur coal. Power plants also utilize scrubbers to clean sulfur from the smoke before it leaves their smokestacks. In addition, the coal industry and the U.S. government have partnered to develop technologies that remove impurities from coal, increasing the efficiency of coal and reducing the amount of coal needed per unit of energy produced.

Carbon Capture and Sequestration

Carbon dioxide emission from coal combustion is also being addressed. Carbon Capture and Sequestration (CCS) separates CO₂ from emissions sources, transports it to a storage location which is typically deep underground and isolates it in a concentrated stream.

There are three main technologies for removing CO₂ from a coal-fired plant: post-combustion, pre-combustion and oxy-fuel combustion.

- Post-combustion carbon capture grabs CO₂ after the coal is burned. Burning coal produces flue gases which include CO₂, water vapor, sulfur dioxides, and nitrogen oxides. The post-combustion process involves separating carbon dioxide and capturing it from the flue gases. This technology is applicable for installation in older power plants and achieved by adding a solvent that absorbs the CO₂ as it travels up a smokestack. The solvent is then heated, releasing water vapor and leaving a concentrated stream of CO₂. Although, post-combustion carbon capture can reduce emissions by as much as 80-90%, the process requires a large amount of energy to compress the gas enough for transport.
- In the pre-combustion carbon capture process, CO₂ is trapped before the coal is burned and diluted by other flue gases. Pre-combustion carbon capture produces a higher concentration of CO₂ than post-combustion. The pre-combustion process is lower in cost but is difficult to employ in older power plants. As with post-combustion, pre-combustion carbon capture can prevent 80-90% of a power plant's emissions from entering into the atmosphere.



- Oxy-fuel combustion carbon capture technology involves the power plant burning coal in oxygen, creating a gas mixture comprising steam and CO₂. The steam and carbon dioxide is cooled and compressed into a gas stream. The oxygen needed in this technique increases costs, but new research is still underway. Oxy-fuel combustion can eliminate 90% of a power plant's emissions.

After CO₂ is captured, it must be transported through a pipeline to an underground storage site. Storage involves injecting CO₂ into underground rock formations in order to let it seep into spaces in porous rock. Rocks overlying the storage site create a seal to keep the gas contained.

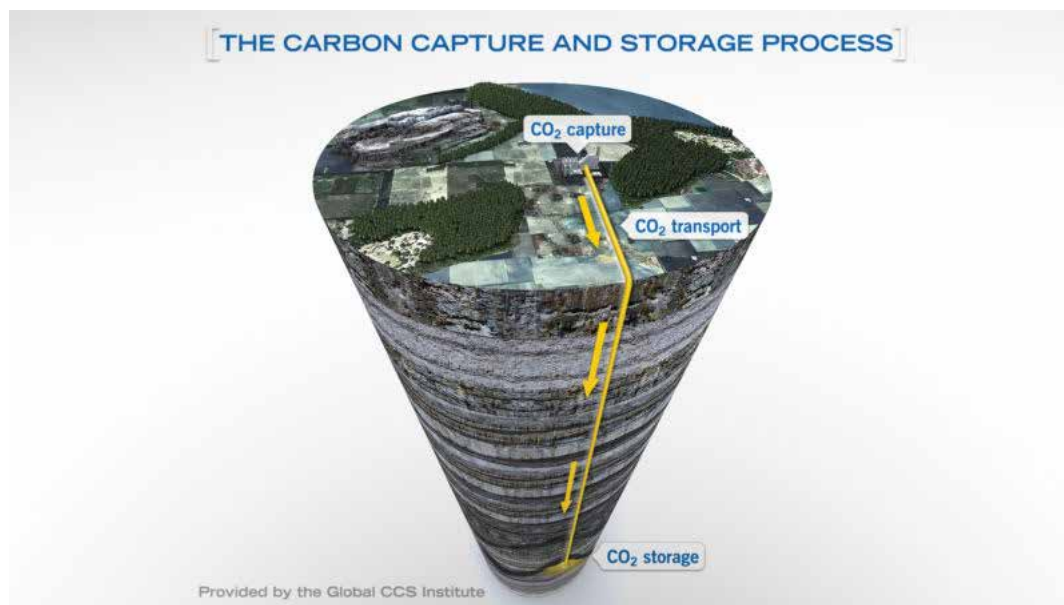


Figure 6.2-2: Carbon Capture and Storage Process²⁵

Carbon capture and storage do not come without risks. The long-term effects of CO₂ seeping into the ground and ground water are not known. Many questions remain on the ultimate viability and the effect these technologies can have on total CO₂ emissions.

Currently, there are not any U.S. coal-fired power plants with CCS technology. On May 11, 2021, City Water, Light, and Power (CWLP) of Springfield, Illinois, announced a 10 MW research project led by the University of Illinois at CWLP's Unit 4.²⁶ Construction is set to begin in June 2021, with operations by 2025.

²⁵ The Carbon Capture and Storage Process [Digital image]. (n.d.). Retrieved April 21, 2021, from <https://www.globalccsinstitute.com/about/what-is-ccs/>

²⁶ Clarion Energy Content Directors - (2021, May 11). Illinois Utility Working with University on DOE-FUNDED Carbon Capture Research Project. Retrieved May 19, 2021, from <https://www.power-eng.com/coal/clean-coal-technologies/illinois-utility-working-with-university-on-doe-funded-carbon-capture-research-project/>



Retirements

As utilities address climate change as part of their long-term planning, the decision of whether or not to reduce reliance on coal is multifaceted. Low-cost renewables and gas, coupled with state and federal regulations, provide strong incentives to mothball coal facilities. Pressured by various stakeholders, many with environmental concerns associated with burning coal, power generators continue to turn to natural gas and renewable energy in the transition to lower-emission fuels. Power generators with plans to retire coal capacity say they are sticking to those plans now more than ever, considering the 2020 election change in the Executive and Congressional branches of the U.S. government.

“Retirement of this generation is going to be needed anyway. Most of these coal plants we’re talking about are going on 60-plus years old. They’re becoming obsolete, and they’re not economic,” Vistra Energy Corp. President and CEO Curtis Morgan said in November 2019. “I think any business that is a capital-intensive business, whether it’s airlines or chemicals or refining or whatever, have to replace their hardware at some point in time. The question is going to be, what kind of hardware are we going to replace it with? I think it’s going to be renewables.”

After a large number of retirements of coal-fired energy plants representing 48 GW in the previous 5-year span, coal retirements are expected to slow in the current year and then steadily increase. As Mr. Morgan alluded to, these retirements generally represent older units with an average age of 51 years. Forecasts for 2022 and beyond show an increased retirement rate, and some services project that coal could make up as little as 8% -11% of the U.S. power generation by 2030. The projected annual coal retirements due to age and economics is shown in Figure 6.2-3, from the Horizons Energy Spring 2020 Status Quo scenario.

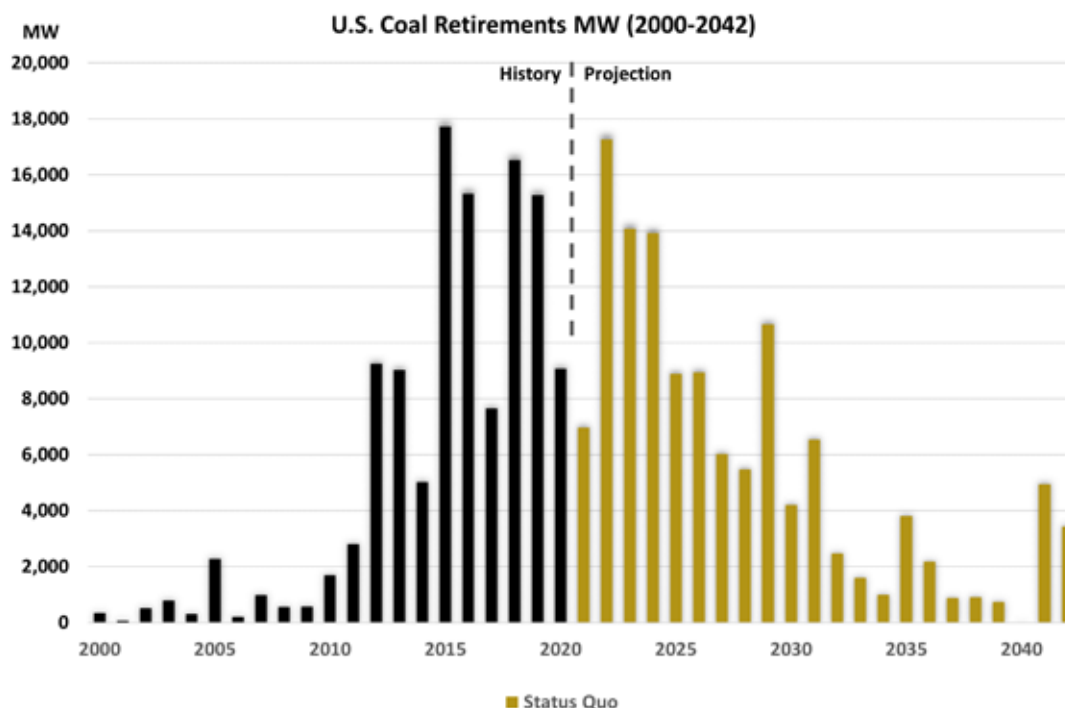


Figure 6.2-3: U.S. Coal Plant Retirements MW (2000-2042)



The projected U.S. coal capacity is shown in Figure 6.2-4, from the Horizons Energy Spring 2020 Status Quo scenario.

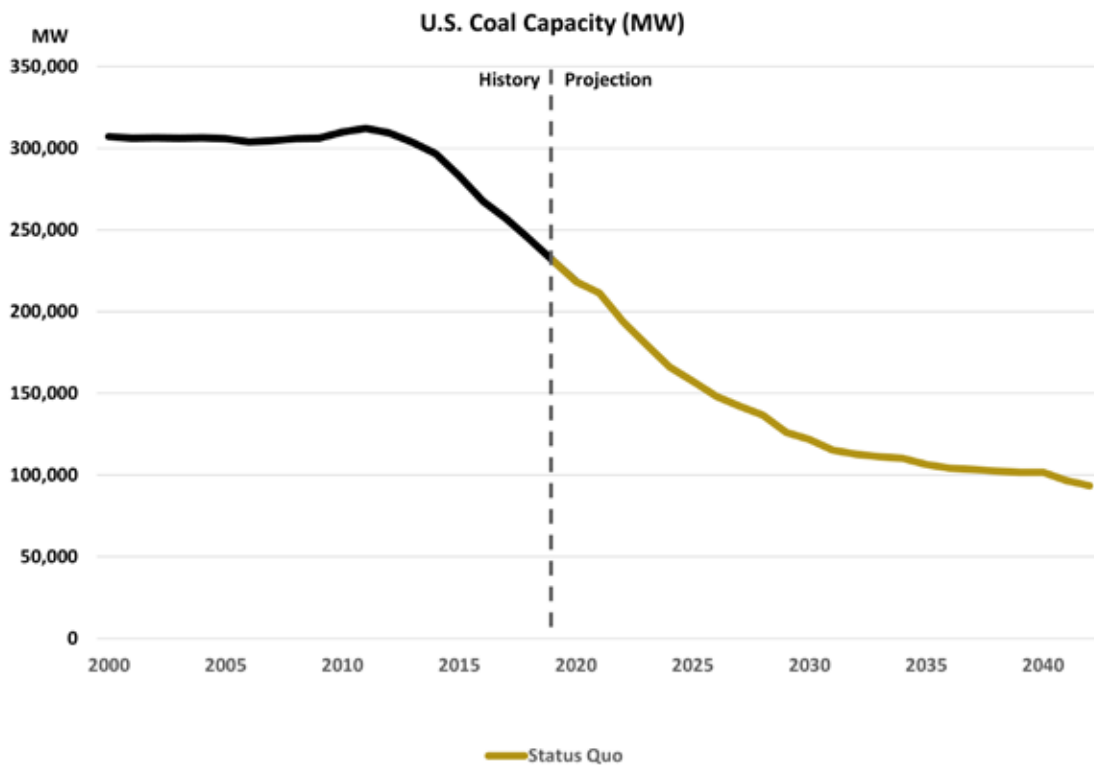


Figure 6.2-4: U.S. Coal Capacity MW

Future of Coal in Kentucky

Despite coal's seemingly bleak future, many generators currently see value in the coal-fired generation still in service. "There's no question that at certain times of the year, the fossil generation fleet is what carries the day," AEP Chairman, President and CEO Nicholas Akins said in a November 2019 interview with S&P Global Market Intelligence. "If the wind's not blowing, there's the need for these types of resources. They will be there as more of an insurance policy." Until battery and renewable technology mature and storage costs decrease, these options do not have the capabilities to replace coal generation in its entirety.

Local pressures also weigh heavily into utility decisions. Coal-fired generation plants provide very significant economic impact to the surrounding communities. Coal power plants employ large number of workers whose wages, in the energy and electricity generation sector, are often higher than the average wage in the communities where they are located. Additionally, these power plants often operate for decades, providing relatively stable employment opportunities for the citizens.

The removal of stable, high-paying jobs can potentially have large impacts on communities and workers. The depth of those economic impacts depends at least in part on the specific characteristics of the plant and the community, including the size of the plant, the number of workers furloughed, and the community's economic characteristics. Many of replacement energy facilities and jobs will locate in different communities from where coal-fired plants are shuttered, and the communities where coal jobs are lost will face significant economic hardship.



6.3 Nuclear Generation

KYMEA does not currently have nuclear in its power supply portfolio.

Overview

A nuclear reactor is the centerpiece of a nuclear power plant. The reactor is where atoms are split in a process called nuclear fission. The subsequent heat that is produced is used to produce steam and eventually spin a turbine to generate electricity. The reactor itself controls the fission process. The fuel, small uranium pellets, are sealed inside metal rods. The fuel rods are immersed in water inside the reactor vessel. The water acts as both a coolant and a moderator. Moderation is done by inserting the control rods into the reactor core to reduce the reaction rate or withdrawn to increase it.

As of April 2020, there were 440 operable nuclear reactors globally, with 95 located in the United States and 19 located in Canada. Since 1990, nuclear reactors have provided roughly 20% of the energy produced in the U.S. As shown in Figure 6.3-1, the United States generates nearly as much nuclear energy as the next three countries combined.

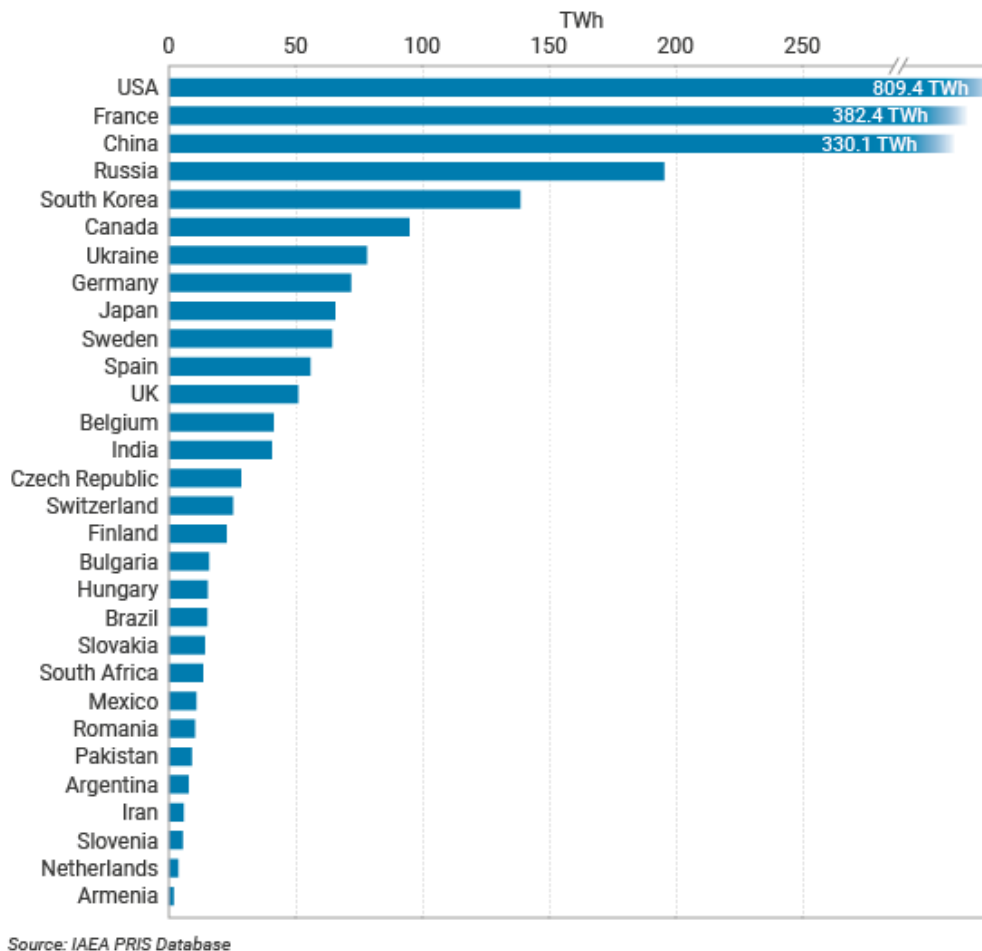


Figure 6.3-1: Nuclear Generation by Country 2019²⁷

²⁷ World Nuclear Association, & IAEA PRIS Database. (2021, March). [Digital image]. Retrieved April 26, 2021, from <https://world-nuclear.org/information-library/current-and-future-generation/nuclear-power-in-the-world-today.aspx#:~:text=%20Nuclear%20Power%20in%20the%20World%20Today%20,in%20about%2020%20research%20reactors.%20In...%20More%20>



Figure 6.3-2 depicts the location, number of units, and NRC jurisdiction region for the U.S. operating commercial nuclear power reactors.

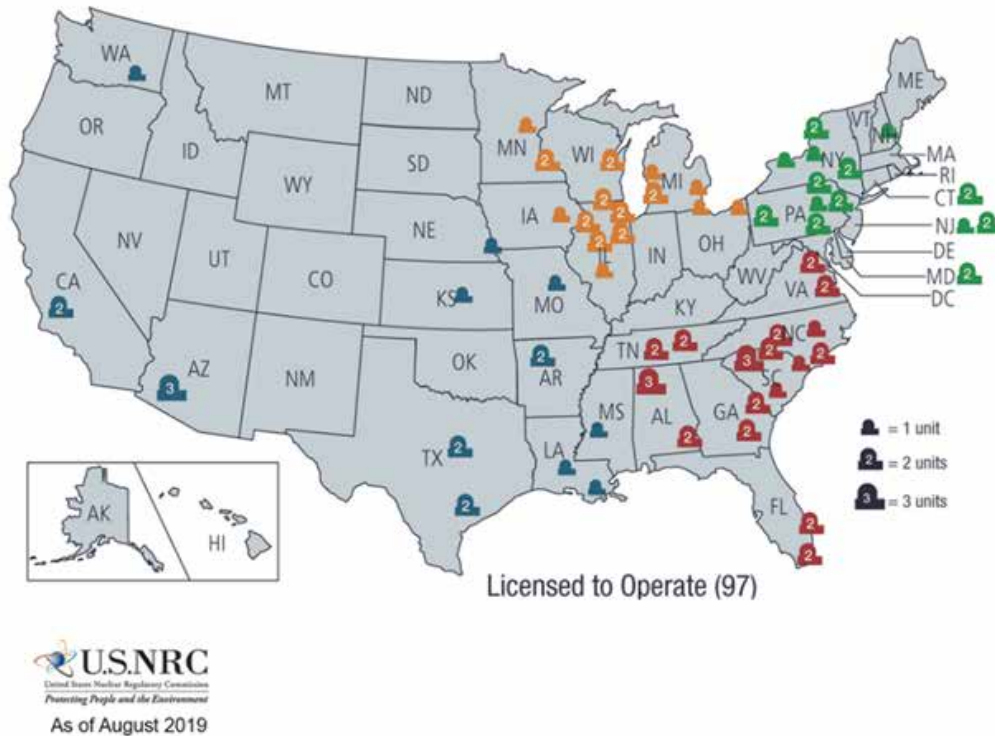


Figure 6.3-2: U.S. Operating Commercial Nuclear Power Reactors²⁸

Nuclear Reactors in the United States

All commercial nuclear reactors in the United States are light-water reactors, either pressurized or boiling reactors. As of June 2019, the Nuclear Regulatory Commission (NRC) has issued 94 license renewals, five of which have subsequently permanently shut down. The U.S. could lose more than 5 GW of nuclear capacity in the near term at the following locations:

Indian Point, NY – 1 unit

Byron, IL – 2 units

Dresden, IL – 2 units

Southern Nuclear Operating Company's Vogtle Electric Operating Plant Unit 3 is on track to come online in November 2021 and will be the first new unit to go online in the U.S. in the last 30 years. Unit 4 will follow shortly.

28 Map of Power Reactor Sites [Digital image]. (2019, August). Retrieved April 21, 2021, from <https://www.nrc.gov/reactors/operating/map-power-reactors.html>



Pressurized Water Reactors

More than 65% of the commercial reactors in the United States are pressurized-water reactors or PWRs. High-pressure water is pumped into the reactor core and is heated by the nuclear fission process. This heated water is used to heat a separate water source via a heat exchanger. This separate water source creates steam which is used to spin a turbine and ultimately produces electricity. The core water cycles back to the reactor and the process is repeated.

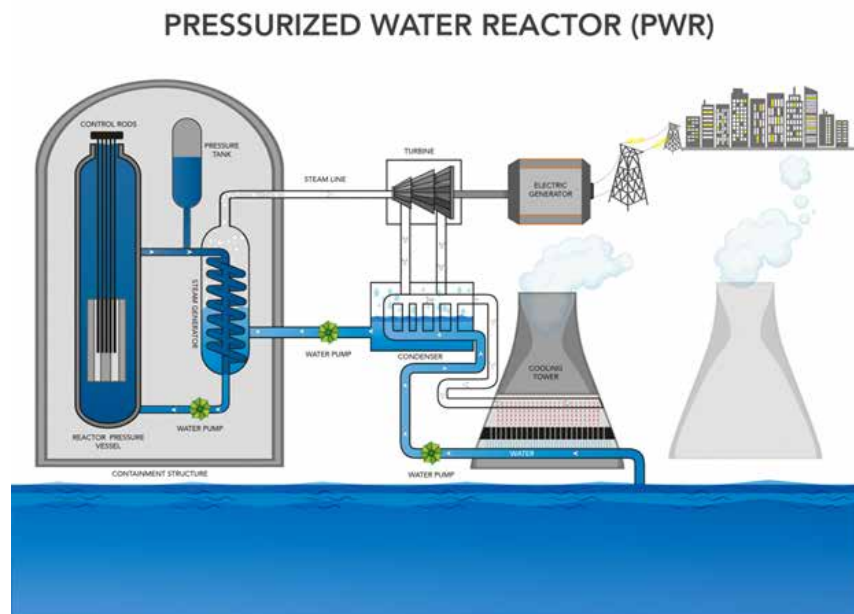


Figure 6.3-3: Pressurized Water Reactor (PWR) Diagram²⁹

29 NUCLEAR 101: How does a nuclear Reactor Work? (2021, March 29). Retrieved April 21, 2021, from <https://www.energy.gov/ne/articles/nuclear-101-how-does-nuclear-reactor-work>



Boiling Water Reactors

Roughly a third of the reactors operating in the United States are boiling water reactors or BWRs.

Unlike PWRs, BWRs produce steam directly inside the reactor vessel. The steam spins the turbine to create electricity, and the unused steam is then condensed back to water and reused in the heating process.

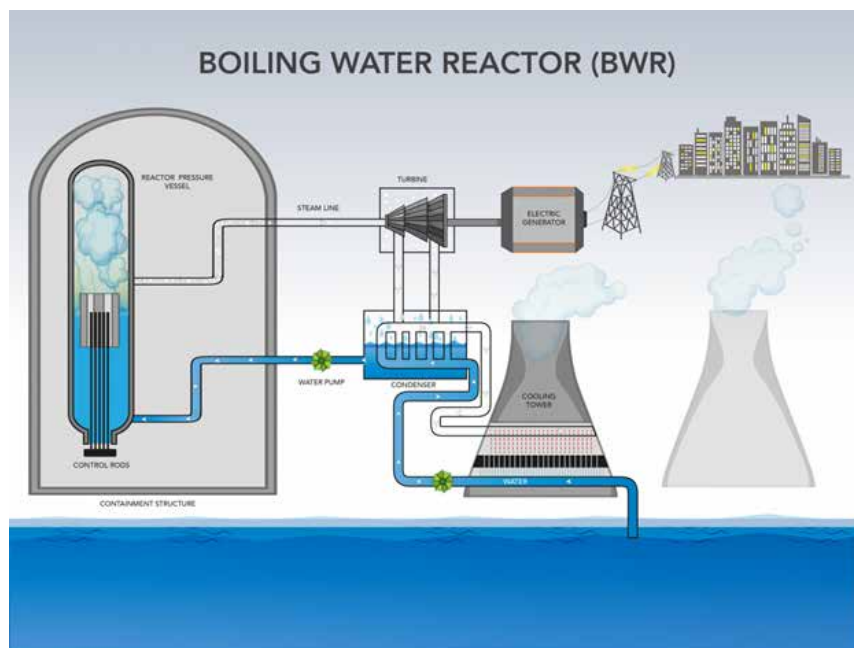


Figure 6.3-4: Boiling Water Reactor (BWR) Diagram³⁰

30 NUCLEAR 101: How does a nuclear Reactor Work? (2021, March 29). Retrieved April 21, 2021, from <https://www.energy.gov/ne/articles/nuclear-101-how-does-nuclear-reactor-work>



Relicensing and Retirements

The Atomic Energy Act of 1954 authorizes the NRC to issue 40-year initial licenses for commercial power reactors. The NRC also has the authority to renew licenses for 20 years at a time. Applications are reviewed for safety and environmental impacts. The NRC can also issue subsequent license renewals that push the operational life of a reactor to 80-years. The renewal process is shown in Figure 6.3-5.³¹

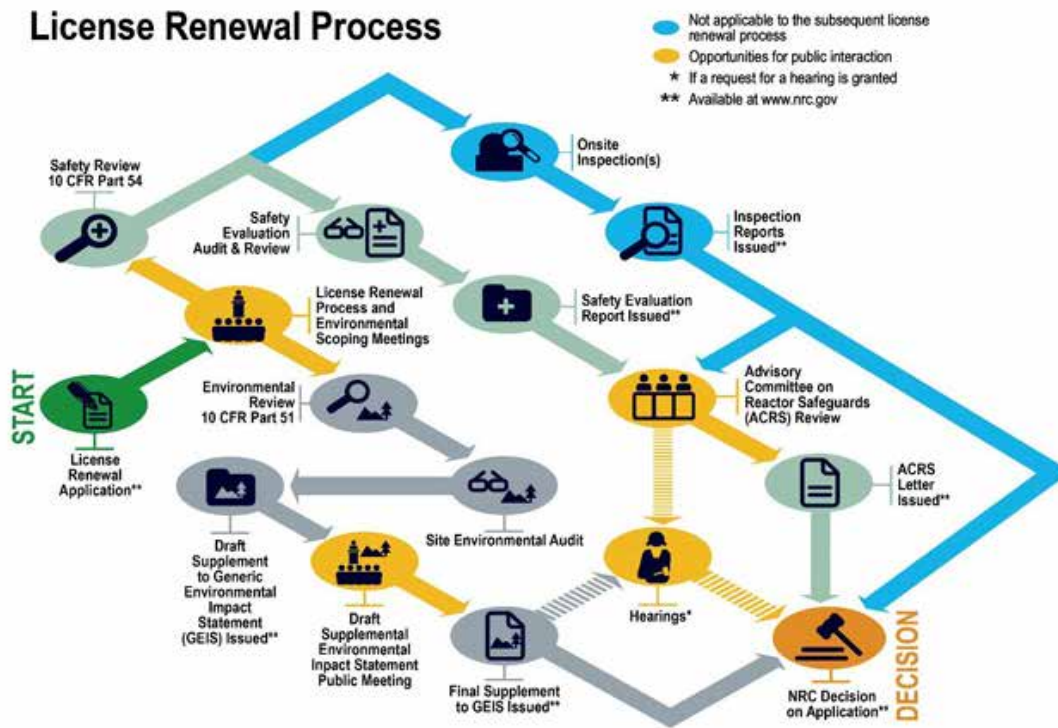


Figure 6.3-5: License Renewal Process Flowchart³²

³¹ Retrieved April 21, 2021, from <https://www.nrc.gov/>

³² Backgrounder on Reactor License Renewal. (2018, October 1). Retrieved April 21, 2021, from <https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/fs-reactor-license-renewal.html>



Figure 6.3-6 details the operational age of the U.S. nuclear power reactor fleet.

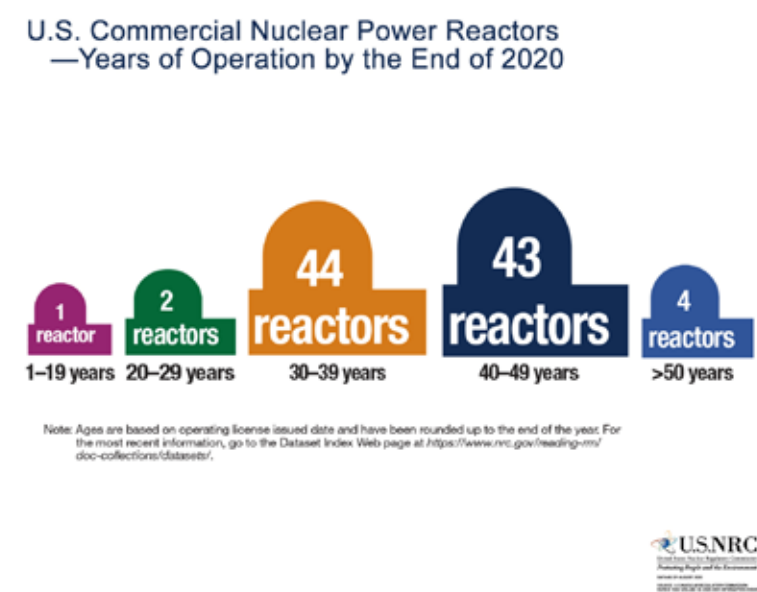


Figure 6.3-6: U.S. Commercial Nuclear Power Reactors - Yrs of Operation by End of 2020³³

33 U.S. Commercial Nuclear Power Reactors - Years of Operation by End of 2020 [Digital image]. (2000, August). Retrieved April 21, 2021, from <https://www.nrc.gov/reading-rm/doc-collections/infographics/commercial-reactors-years-of-operation-end-of-2020.png>



Nuclear generation does provide for a carbon-free energy source directly in the form of produced electricity, but nuclear reactors can also provide carbon-free processed heat for other industrial applications. Hydrogen production is one of those applications. Hydrogen is being tested as an alternative fuel for gas turbines and will be discussed later in this report. Based upon Horizons Energy Spring 2020 Scenarios, the Status Quo scenario has nuclear capacity in the U.S. declining, as shown in Figure 6.3-7.

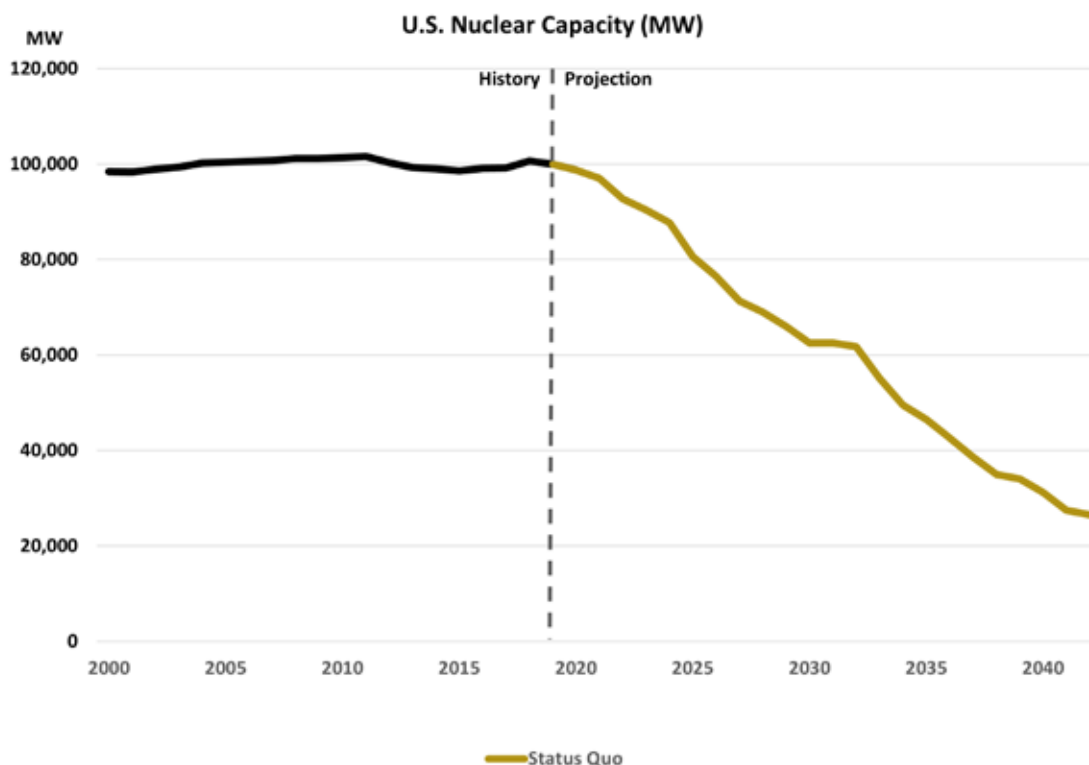


Figure 6.3-7: U.S. Nuclear Capacity

Risk Considerations

Cost: Nuclear construction is very capital intensive and is subject to overruns due to compliance hurdles and oversight.

Environmental: Spent nuclear fuel is radioactive and requires thousands of years to stabilize. There have been recent strides taken in reusing spent fuel where the radioactivity has been reduced.

Security: Nuclear reactors are potential targets for terrorist activities.

Accidents: Natural disasters, as well as human error, can cause accidents at nuclear facilities. The most recent accident involving a natural disaster was seen at Japan's Fukushima Plant in 2011, caused by a massive tsunami. Human error caused the Chernobyl accident in the Ukraine in 1986.

Siting: Given the public perception of nuclear reactors and the potential for the release of deadly radioactive fallout, siting of new plants can become highly contested.



Future of Nuclear in Kentucky

Small Modular Reactors

Conventional nuclear reactors require large capital investments, large physical footprints, a long lead-time for construction, and large output sizing. Nuclear construction is also subject to negative pressures due to public perception that they are not safe. In looking to the future, the Department of Energy (DOE) has been in the process of studying Advanced Small Modular Reactors (SMRs) as a way to develop safe, clean, and affordable nuclear power options. These SMRs can range in sizes from 10 MW up to 300 MW. They can be used to produce nuclear power, process heat, desalination, and other industrial uses. Current designs use a myriad of coolants, such as light water, gas, liquid metal, or molten salt.

SMRs require a small footprint and have less capital investments than traditional nuclear sites. They are flexible in siting and sized to fit the needs of the communities they serve. They can be built in factories, which reduces cost, while maintaining stringent construction design criteria.

The DOE has provided substantial support to light water-cooled SMRs, which are under review by the NRC with a hopeful deployment in 2029. In FY 2019, the DOE initiated an Advanced SMR R&D program. Significant hurdles remain in bringing SMRs to market, and government support will be required. Through the Advanced SMR R&D program, the DOE has partnered with NuScale Power and Utah Associated Municipal Power Systems to unveil this technology at the Idaho National Laboratory later this decade. The NRC is expected to certify NuScale's design in August 2021. This partnership will provide benefits to other reactor developers by resolving many licensing issues and technical problems. The DOE's plan is to promote U.S. energy independence by providing a future supply of clean and reliable baseload power.

Fusion energy

Fusion energy developments recently appeared in an article in Popular Mechanics Magazine. Fusion is a nuclear reaction that occurs when nuclei smash together to form a heavier nucleus. It is the same reaction that the sun and other stars use to create energy. General Fusion (a Canadian company backed by Jeff Bezos and Tobias Lutke) and Commonwealth Fusion Systems (an American company backed by Bill Gates) announced that their technologies will be ready for demonstration as early as 2025 with online operations in 2035. The technology is based upon magnetized target fusion, which dates back to the 1970s.

Fusion reactors produce helium, an inert gas, as a waste product and produces and consumes small amounts of tritium within the plant. Tritium is radioactive, but unlike nuclear waste from a fission plant, the half life is short as opposed to the millions of years required for radioactive nuclei.

KYMEA did not receive any nuclear resource options in response to its RFP2020. Additionally, Kentucky does not have any nuclear resources located in the Commonwealth.



6.4 Geothermal Generation

KYMEA does not currently have geothermal energy in its power supply portfolio.

Overview

Geothermal reservoirs are naturally occurring areas of hydrothermal resources. These reservoirs are deep below the earth at depths exceeding one mile and are largely undetectable above ground. They are visibly shown as volcanoes, hot springs and geysers. Most geothermal resources are near the boundaries of the earth's tectonic plates. Most U.S. resources exist in the western states. Figure 6.4-1 shows a map of geothermal resource sites in the United States.

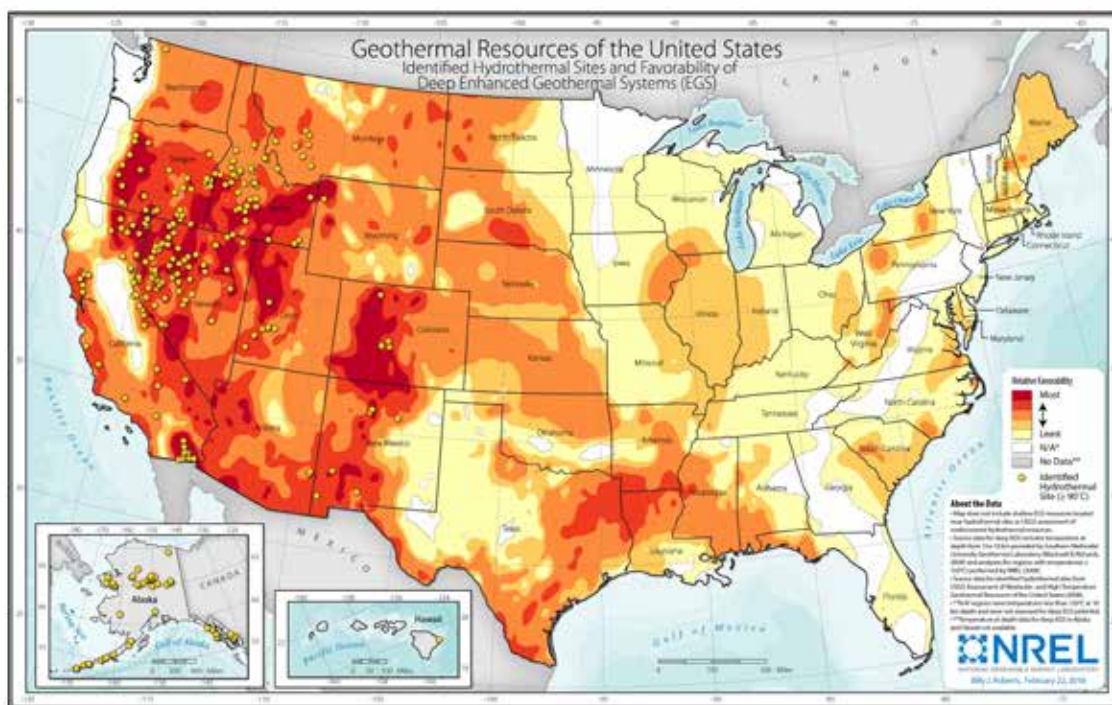


Figure 6.4-1: Geothermal Resource Sites of the U.S.³⁴

Geothermal power plants use hydrothermal resources that have both water and heat. Geothermal power plants require high-temperature (300°F to 700°F) hydrothermal resources that come from either dry steam wells or from hot water wells. People access these resources by drilling wells into the earth and then piping steam or hot water to the surface. The hot water or steam powers a turbine that generates electricity. There are three basic types of geothermal power plants:

34 Geothermal Resources of the United States [Digital image]. (2018, February 22). Retrieved April 21, 2021, from <https://www.nrel.gov/gis/assets/images/geothermal-identified-hydrothermal-and-egs.jpg>



Dry Steam Plants

These plants use steam directly from a geothermal reservoir to turn generator turbines. The first geothermal power plant was built in 1904 in Tuscany, Italy, where natural steam erupted from the earth. Figure 6.4-2 shows the basic framework of a dry steam power plant.

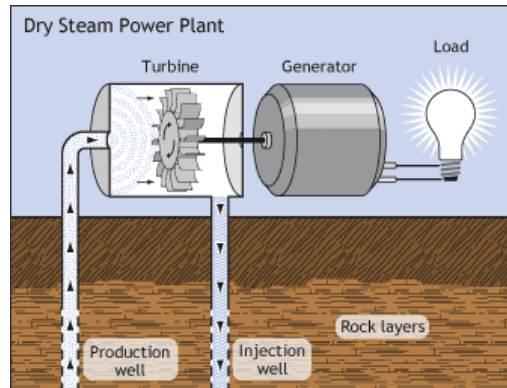


Figure 6.4-2: Dry Steam Power Plant³⁵

Flash Steam Power Plant

These plants take high-pressure hot water from deep inside the earth and convert it to steam to drive generator turbines. When the steam cools, it condenses to water and is injected back into the ground to be used again. Most geothermal power plants are flash steam plants. Figure 6.4-3 shows the basic framework of a flash steam power plant.

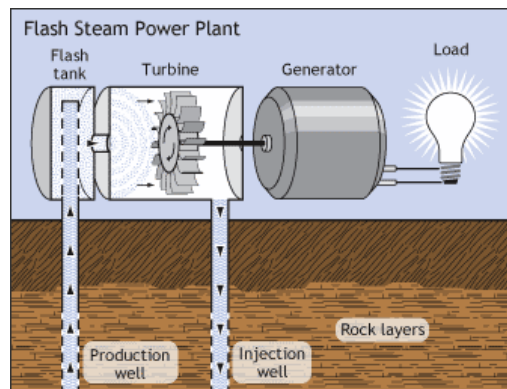


Figure 6.4-3: Flash Steam Power Plant

Binary Cycle Power Plant

These plants transfer the heat from geothermal hot water to another liquid. The heat causes the second liquid to turn to steam, which is used to drive a generator turbine.

The output of these plants is carbon-free and considered baseload generation as the rate of energy extraction can be balanced with each reservoir's rate of heat recharge. Figure 6.4-4 shows how a binary cycle power plant operates.

35 Electricity generation-Geothermal. (n.d.). Retrieved April 26, 2021, from <https://www.energy.gov/eere/geothermal/electricity-generation>

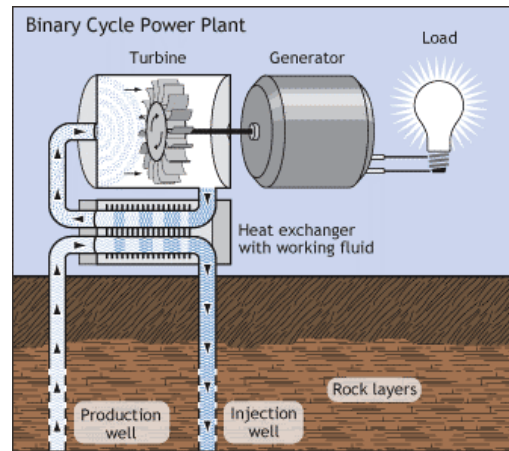


Figure 6.4-4: Binary Cycle Power Plant

Risk Considerations

Earthquakes: Drilling miles into the earth and removing material can cause the surrounding ground to shift.

Location: As shown in Figure 6.4-5, geothermal energy is limited to the western part of the U.S., Alaska, and Hawaii.

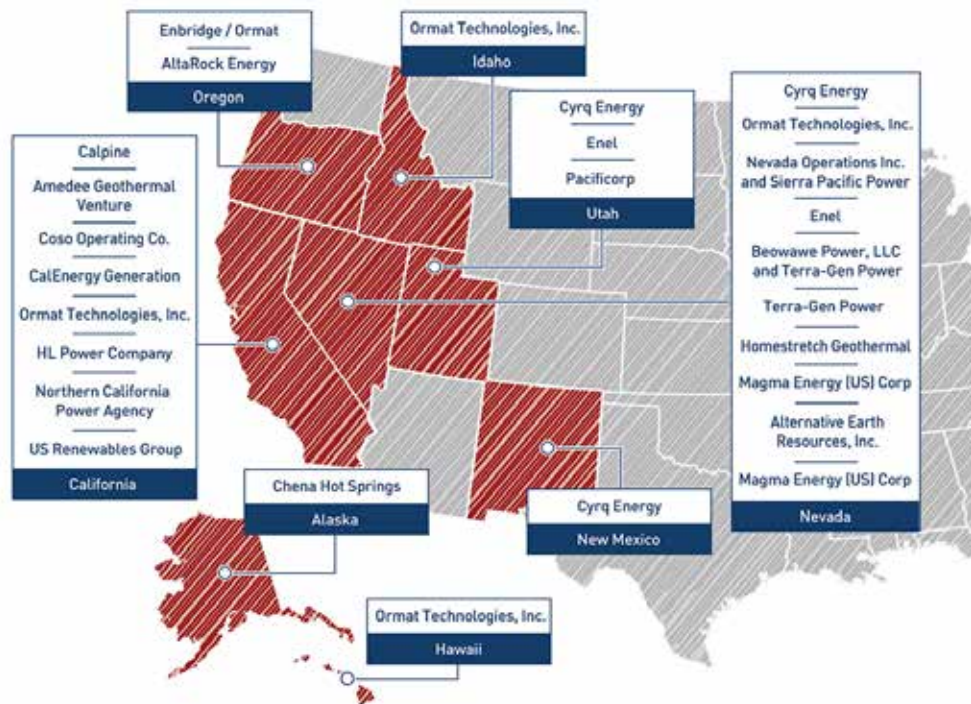


Figure 6.4-5: Existing Geothermal Energy in the U.S.³⁶

³⁶ Smith, F. M., & Rozansky, R. (2020, April 3). Existing Geothermal Industry in the United States [Digital image]. Retrieved April 21, 2021, from <https://clearpath.org/our-take/harnessing-heat-how-the-federal-government-can-advance-geothermal-energy/#essential-facility>



Future of Geothermal Energy in Kentucky

Figure 6.4-4 shows historical and projected geothermal capacity in the U.S. from the Horizons Energy Spring 2020 Status Quo scenario.

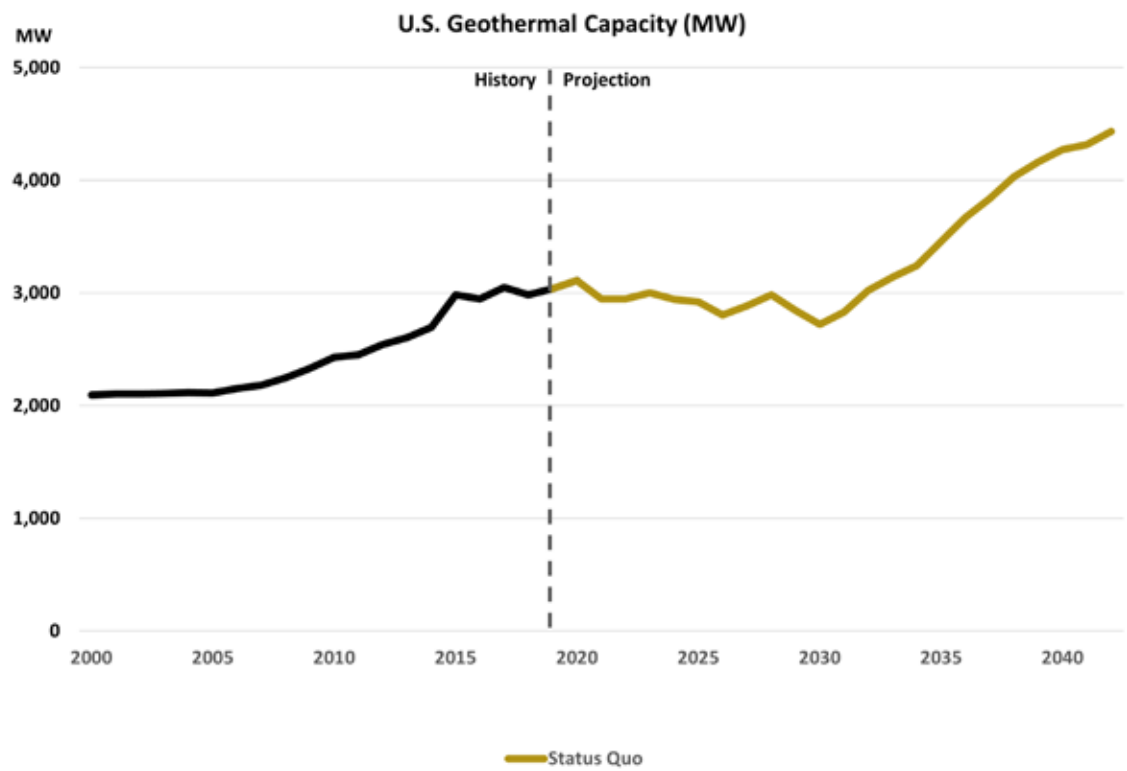


Figure 6.4-6: U.S. Geothermal Capacity (MW)

Given the lack of geothermal sites in close proximity to Kentucky, the feasibility of utilizing a geothermal power plant is very low.



6.5 Natural Gas Generation

Paducah Power System and KYMEA entered into a ten-year power supply contract for 90 MW of capacity and energy from the PPS Power Plant No 1.

PPS Power Plant No 1, located in western Kentucky, is a 124 MW natural gas-fired power plant consisting of two 62 MW combustion turbines. The power plant reached commercial operation in June 2010. Service under the contract commenced on May 1, 2019.



Paducah Power System - PPS Power Plant No. 1

Location: Paducah, KY

Type: Natural gas fired combustion turbine plant

History: The power plant reached commercial operation in June 2010. PPS Power Plant No 1 consists of two 62 MW combustion turbines.

PPA Expiration: May 31, 2029

Capacity: 90 MW

Overview

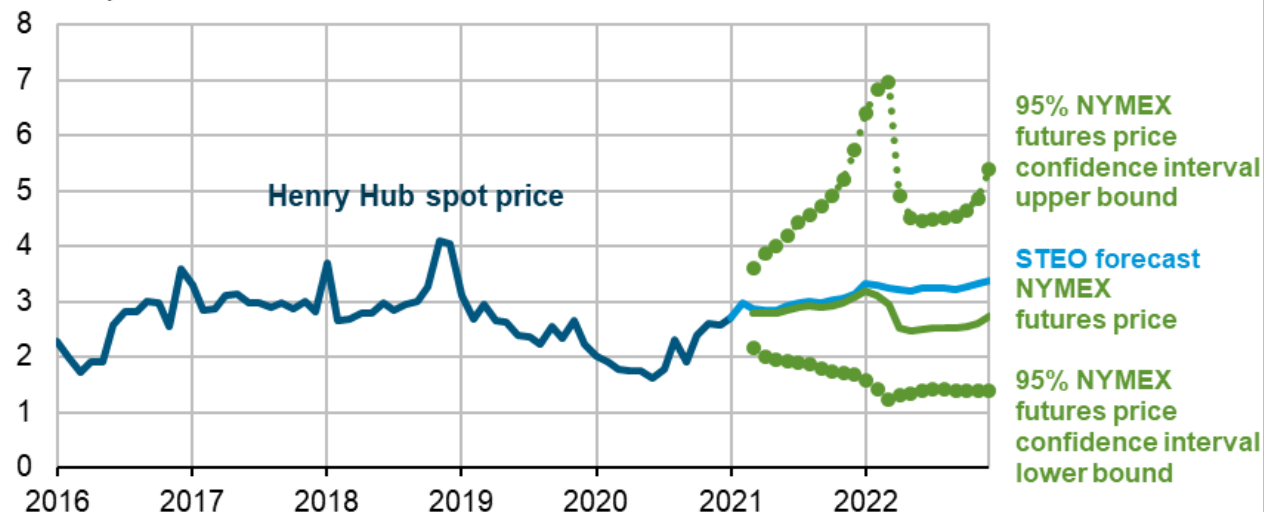
Natural gas is a popular fuel source for electricity generation for a number of reasons. It is reliable, affordable, produced domestically, and produces significantly less harmful emissions than other traditional fossil fuel energy sources. Natural gas plants can be started up in a very short amount of time, enabling them to support peak load periods and act as back-up for renewable sources of power. In 2020, natural gas generation comprised 40% of total U.S. electricity generation, but this share is expected to decline slightly in 2021 (37%) and 2022 (35%) due to rising natural gas commodity prices.³⁷

37 SHORT-TERM ENERGY OUTLOOK. (2021, February). Retrieved February 2021, from <https://www.eia.gov/outlooks/steo/report/electricity.php>



Henry Hub natural gas price and NYMEX confidence intervals

dollars per million Btu



Note: Confidence interval derived from options market information for the five trading days ending Feb 4, 2021. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Sources: U.S. Energy Information Administration, Short-Term Energy Outlook, February 2021, and CME Group



Figure 6.5-1: Henry Hub Natural Gas Price and NYMEX Confidence Intervals³⁸

Gas-fired power plants are comprised of:

- An air compressor that compresses air which is then moved at a very high speed into the combustion chamber.
- A combustion system which includes various fuel injectors that inject fuel into the combustion chamber that is already filled with air, causing high temperature and a high pressure gas stream to enter and expand through the turbine.
- A turbine that has both stationary and rotating blades that are driven by the hot gas stream. The rotating blades run the compressor and spin the generator producing electricity.

38 SHORT-TERM ENERGY OUTLOOK. (2021, February). Retrieved February 2021, from <https://www.eia.gov/outlooks/steo/report/electricity.php>



Simple Cycle Units

Simple cycle gas plants, shown in Figure 6.5-2, also known as combustion turbines, are a type of natural gas power plant which operates by propelling hot gas through a turbine to generate electricity. Simple cycle gas plants can respond to the fluctuating demands for electricity and have great operational flexibility, which means they can be started up quickly to meet these needs; however, this comes at the cost of a higher heat rate of 9,725 Btu/kWh (35% efficiency). Since they have relatively lower efficiency, simple cycle power plants are typically not run for many hours in a year.

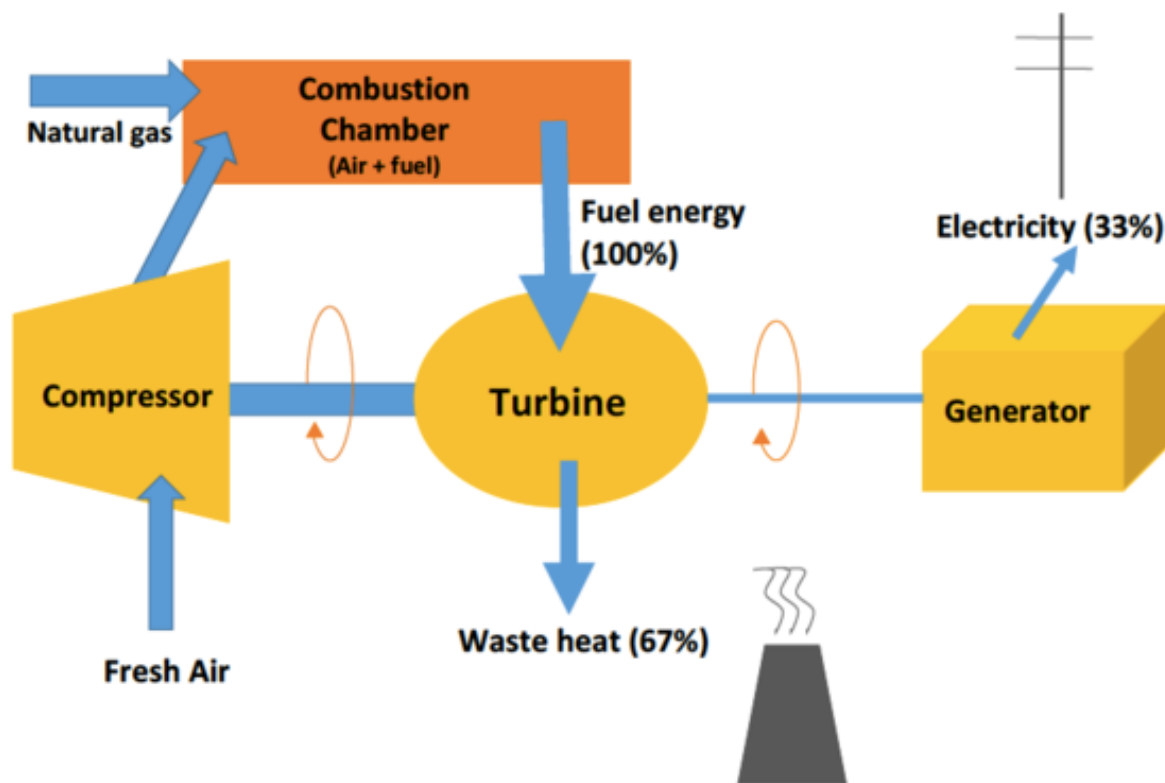


Figure 6.5-2: Simple Cycle Gas Plant Diagram³⁹

39 Schematic Diagram of a Simple Gas Plant [Digital image]. (2018, September 3). Retrieved April 21, 2021, from https://energyeducation.ca/encyclopedia/Simple_cycle_gas_plant



Combined Cycle Units

A combined cycle unit, shown in Figure 6.5-3, utilizes electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or a heat recovery steam generator for utilization by a steam turbine in the production of electricity. The most efficient combined cycle units have a 5,500 Btu/kWh heat rate (62% efficiency). Coupled with low natural gas prices, the combined cycle units are becoming the workhorse for the nation's baseload generation needs, displacing nuclear and coal units.

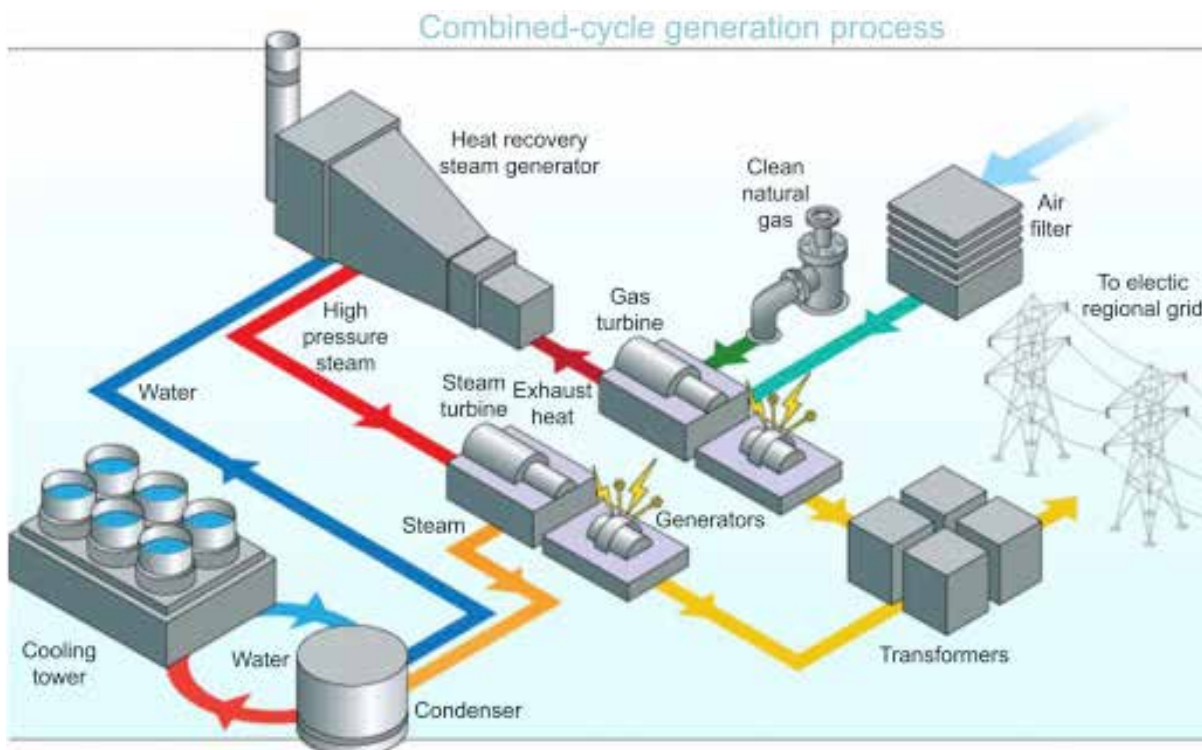


Figure 6.5-3: Combined Cycle Gas Plant Diagram⁴⁰

40 Combined Cycle Generation Process [Digital image]. (2014). Retrieved April 22, 2021, from <https://ars.els-cdn.com/content/image/3-s2.0-B9780081008041000128-f12-10-9780081008041.jpg>



Reciprocating Engines

Reciprocating internal combustion engines (RICE) are becoming increasingly popular for larger utility-scale power generation applications, especially in areas with high levels of electricity generation from intermittent sources such as wind and solar. The recent increase in natural gas or dual-fuel capable RICE units has been driven in part by advancements in engine technology that increase operational flexibility. Reciprocating engines tend to be smaller than other types of natural gas-fired electricity generators, which allows for quick operation to deploy a single unit or multiple units to meet the energy needs. The RICE unit average heat rate in simple cycle operation is 8,000 Btu/kWh (43% efficiency), which falls between the combined cycle and simple cycle units⁴¹.

The reciprocating engine gas plant diagram shown in Figure 6.5-4 includes a heat recovery system generator (HRSG). The HRSG adds additional efficiency to the plant by using waste heat to either generate electricity or supply steam for heating load. The operation is referred to as combined heat and power (CHP).

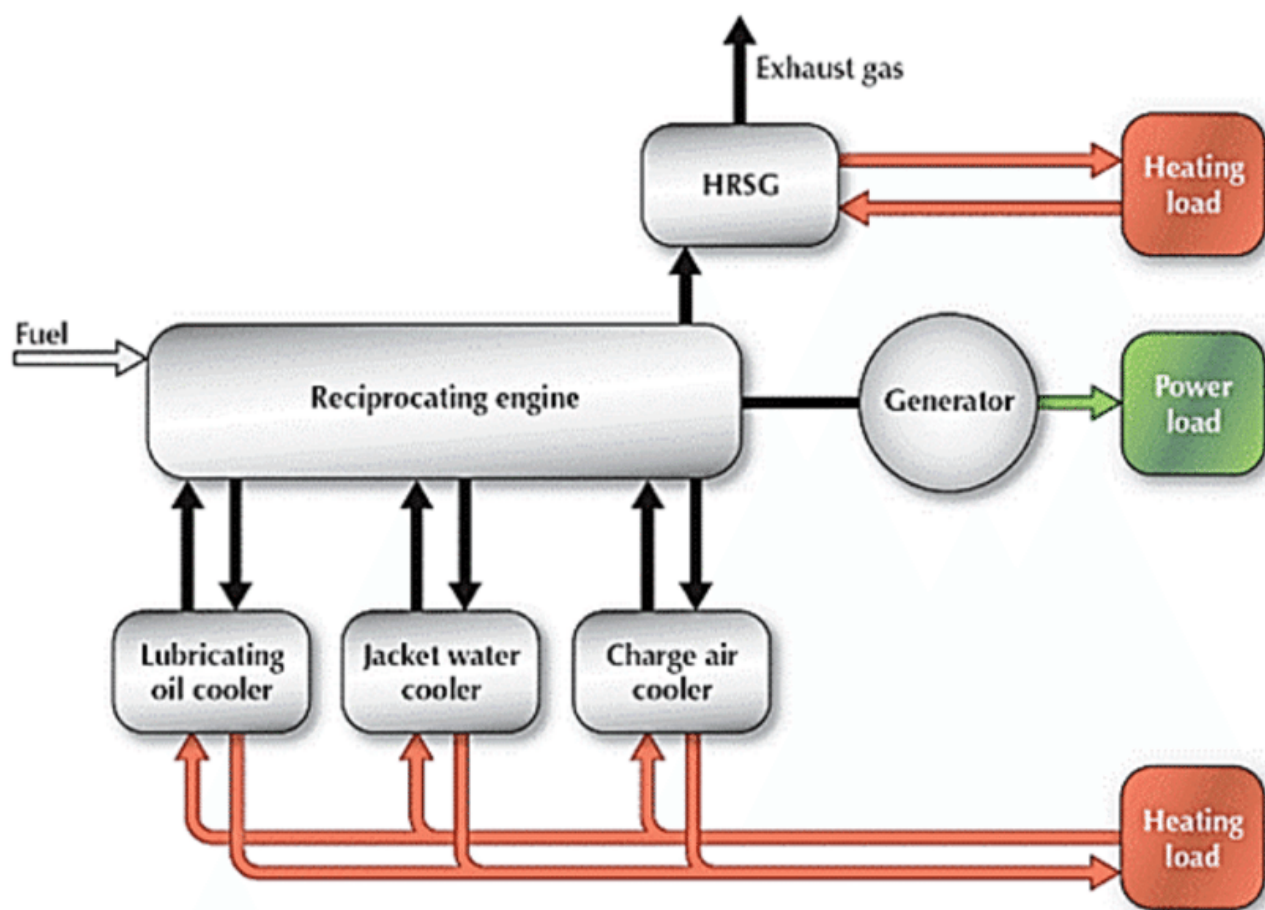


Figure 6.5-4: Reciprocating Engine Gas Plant Diagram⁴²

⁴¹ How gas turbine power plants work. (n.d.). Retrieved April 22, 2021, from <https://www.energy.gov/fe/how-gas-turbine-power-plants-work>

⁴² Apunda, Moses & Benard, Oloo & Nyangoye, Benard & Otieno, Moses. (2017). Selection of a Combined Heat and Power (CHP), and CHP Generation Compared to Buying of Electrical Power from the National Grid and Separate Thermal Heat Production. Open Science Journal. 2. 10.23954/osj.v2i3.1170.



Risk Considerations

Natural gas commodity price volatility represents the primary risk associated with all natural gas combined cycle technology. Hydraulic fracking technology and the ensuing upward amount of available shale gas have the effect of stabilizing these commodity price levels, but the fact remains that natural gas prices remain near all-time lows and have nowhere to go but up.

Potential compliance liabilities associated with fracking and increased demand for U.S. exports of natural gas are risk considerations. Current administration regulations on fracking at the federal level could also have an effect on future gas prices and should be considered when analyzing natural gas resources.

The risk of delivering the gas commodity to a gas facility is something that needs to be accounted for. Firm gas supply contracts provide a hedge against commodity availability disruptions but do not guarantee delivery from the source to the gas facility. Much like the risk of not being able to deliver energy from a gas plant to load due to transmission issues, there exists the same risk of not being able to transport fuel to the plant to produce the energy. In order to hedge gas transportation risk, gas plant off-takers can procure non-interruptible firm transportation. This service will add incremental production costs but will alleviate supply interruption risks during high usage. Firm transportation hedging is well suited for highly efficient, baseload natural gas combined cycle facilities. However, absorbing those costs for peaking facilities with lower capacity factors is not a cost-effective solution. In order to hedge against commodity delivery interruptions for peaking facilities, dual fuel strategies can be employed. This can be done via fuel oil or LNG stored locally at the actual facility in tanks.



Future of Natural Gas in Kentucky

Kentucky relies heavily on natural gas for its electricity needs. Gas-fired generation produced 14.8 million MWh in 2019 and accounted for 20% of the Commonwealth's electric generation. Historically, Kentucky relied on receiving natural gas via pipelines from the U.S. Gulf Coast; but, recently, it began receiving additional natural gas from the Marcellus and Utica shale formations in West Virginia, Ohio, and Pennsylvania. Kentucky has 22 underground storage facilities for natural gas, which can contain 222 billion cubic feet of gas (approximately 2.4% total U.S. storage capacity).⁴³

Figure 6.5-5 shows historical and projected natural gas capacity in the U.S. from the Horizons Energy Spring 2020 Status Quo scenario.

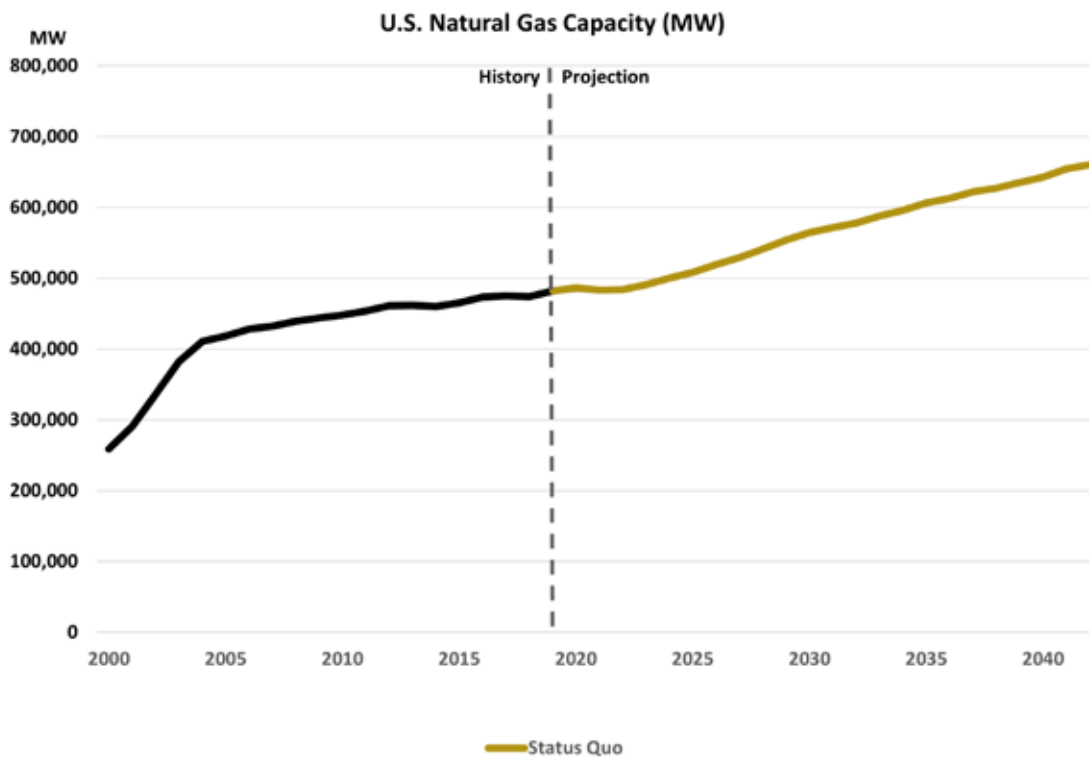


Figure 6.5-5: U.S. Natural Gas Capacity (MW)

43 Kentucky State Profile and Energy Estimate. (2020, June 18). Retrieved April 22, 2021, from <https://www.eia.gov/state/analysis.php?sid=KY>



6.6 Biomass Generation

KYMEA does not currently have biomass energy in its power supply portfolio.

Overview

Biomass is simply renewable energy from plants and animals. Up until the mid-1800's, biomass was responsible for the largest source of energy consumption in the U.S. The energy in biomass material is created from the sun through photosynthesis and is stored as chemical energy. The sources include:

- Wood and wood processing wastes
- Agricultural crops and waste materials
- Food, yard, and wood waste in garbage
- Animal manure and human sewage

Figure 6.6-1 shows types of biomass.

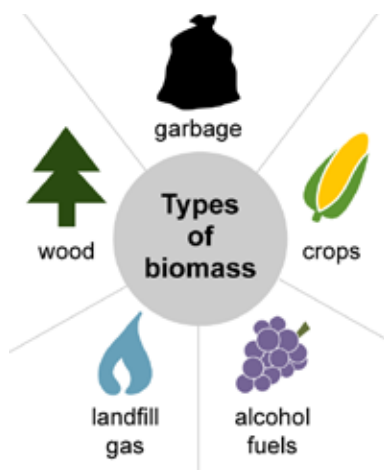


Figure 6.6-1: Types of Biomass⁴⁴

⁴⁴ U.S. energy Information administration - Biomass Explained. (2020, August 28). Retrieved April 22, 2021, from <https://www.eia.gov/energyexplained/biomass/>



Energy is created from biomass via:

- Direct combustion to produce heat (most common)
- Thermochemical conversion
- Chemical conversion
- Biological conversion

According to the EIA, in 2019, biomass provided nearly five quadrillion BTUs of energy from the following sources:

- 46% from wood and wood-derived biomass
- 45% from biofuels, mainly ethanol
- 9% from municipal waste

The breakdown of consumption is shown in Figure 6.6-2.

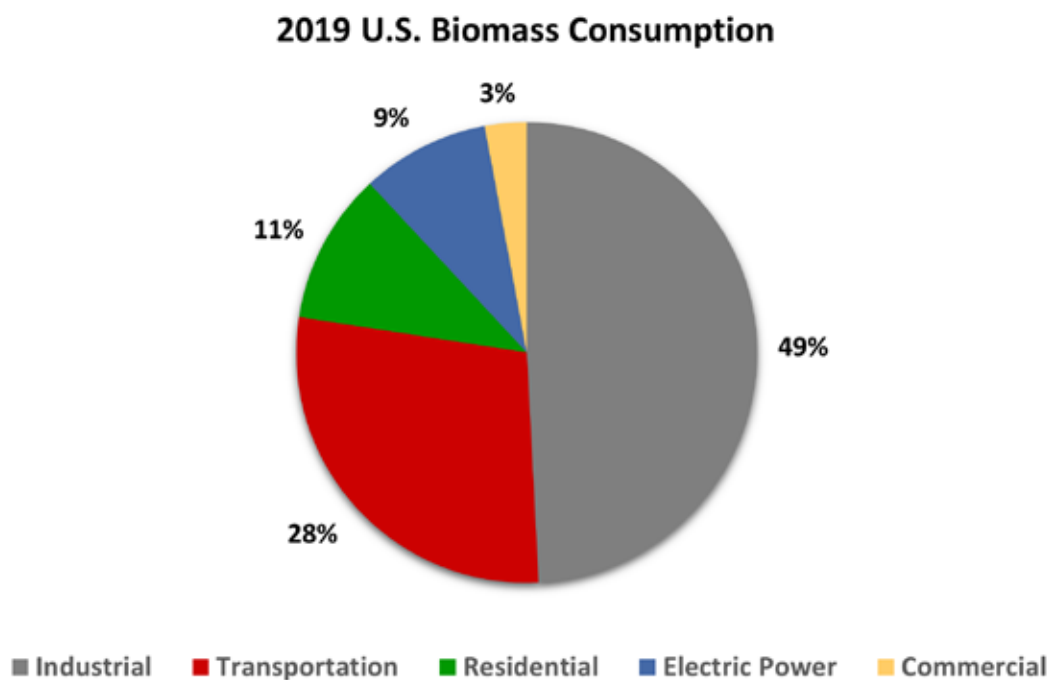


Figure 6.6-2: 2019 U.S. Biomass Consumption



The electric industry uses wood primarily via direct combustion in a boiler to produce steam which spins a turbine and eventually generates electricity. Biomass can also be converted to a gaseous or liquid fuel, where it can be burned in a conventional boiler or a gas turbine.

Figure 6.6-3 shows the U.S. biomass capacity projections from the Horizons Energy Spring 2020 Status Quo scenario.

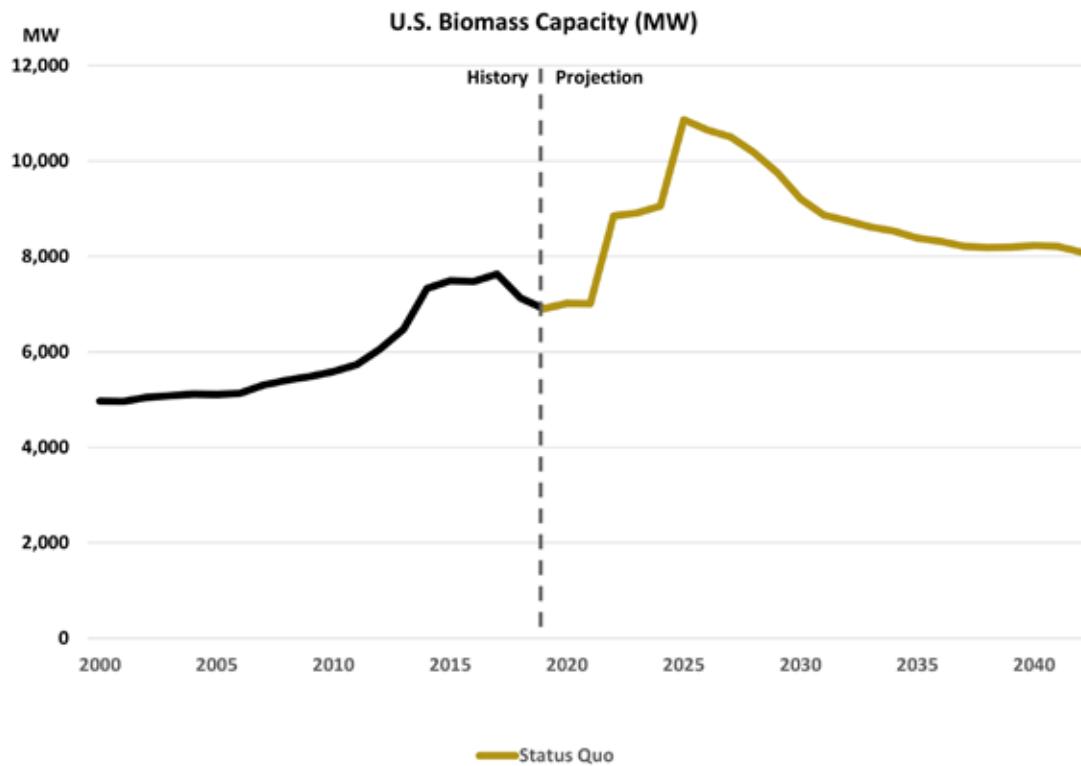


Figure 6.6-3: U.S. Biomass Capacity (MW)



Figure 6.6-4 shows locations of solid biomass resources in the U.S. The feedstock includes forest and primary mill residues, secondary mill residues, and urban wood waste.

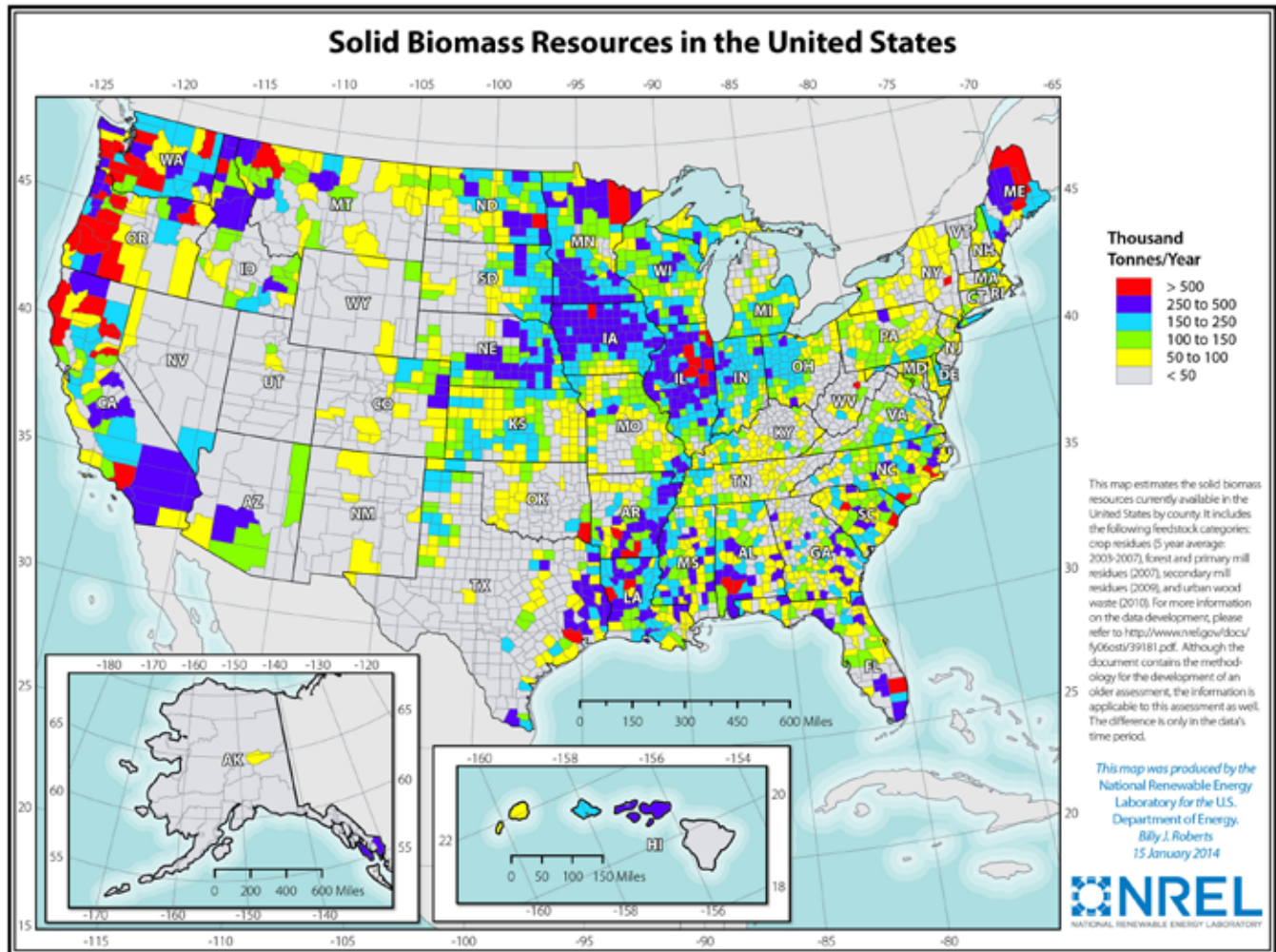


Figure 6.6-4: Solid Biomass Resources in the U.S.⁴⁵

Risk Considerations

Risks associated with biomass center around access to reliable dedicated fuel sources. As most power production is done by combusting wood products, having contracts with multiple fuel suppliers would be a large hurdle to clear.

45 Solid Biomass Resources in the United States [Digital image]. (2014, January 15). Retrieved April 22, 2021, from <https://www.nrel.gov/gis/assets/images/national-biomass-total-2014-01.jpg>



Future of Biomass in Kentucky

According to the EIA, roughly 0.6% of Kentucky's electricity generation came from biomass, as shown in Figure 6.6-5. Most biomass facilities in Kentucky are fueled by landfill gas, but the largest is fueled by wood. Kentucky has the infrastructure to support biogas as an energy resource, but the economics compared to other options make feasibility a challenge. According to the National Renewable Energy Laboratory's (NREL) 2020 Annual Technology Baseline, a dedicated biogas plant has a CAPEX of \$4.348/kW with a fuel cost of \$42/MWh.



Figure 6.6-5: Kentucky Biomass Generation⁴⁶



6.7 Hydrogen Generation

KYMEA does not currently have any hydrogen in its power supply portfolio.

Overview

Hydrogen, the lightest element in the periodic table, is the most abundant chemical substance on earth. Hydrogen is not normally found by itself in nature; it must be produced from other compounds containing it. Hydrogen can deliver and store energy, although it is not an energy carrier. Hydrogen's uses include petroleum refining, fertilizer production, transportation, and fuel cells to produce electricity. Of the nearly ten million metric tons of hydrogen that are produced annually in the U.S., 95% is produced by centralized reforming of fossil fuels, primarily natural gas. Other production techniques include photoelectrochemical cells, solar thermochemical systems, and electrolysis. When hydrogen is produced via electrolysis from zero carbon emitting resources, the resulting fuel is carbon-free. The process of electrolysis uses electricity to split water into hydrogen and oxygen in an electrolyzer unit. The basic principle of hydrogen production electrolysis is shown in figure 6.7-1.

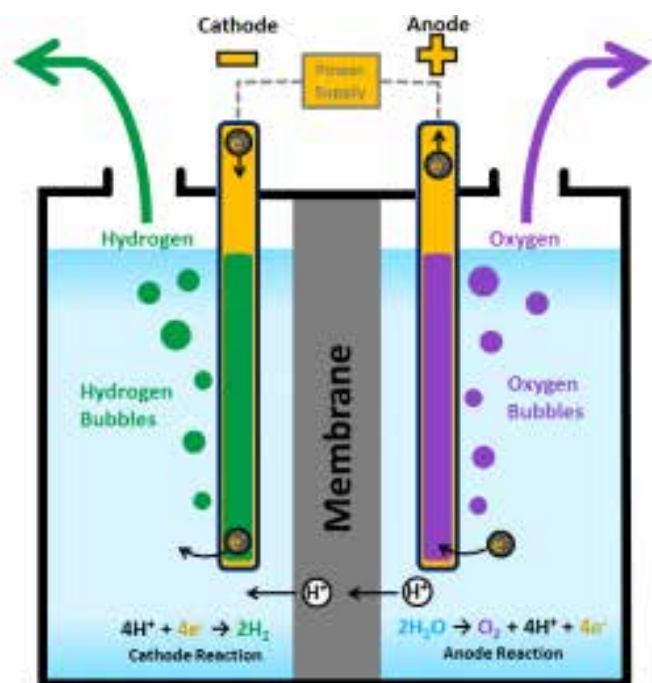


Figure 6.7-1: Hydrogen Production Electrolysis⁴⁷



The challenge for hydrogen production is making it cost competitive with other fuels. Most hydrogen in the U.S. is produced close to where it is used. Hydrogen contains less energy per unit of volume compared to other fuels, so transporting and storing is an expensive endeavor. Producing hydrogen at locations where it is used increases capital costs. Production of hydrogen at a remote location is cheaper up front, but more expensive to transport. Storage of hydrogen can be done as a liquid or a gas. In a gaseous state, hydrogen can be stored in high-pressure tanks or in subterranean caverns, such as salt mines for larger volumes. Storing hydrogen as a liquid requires cryogenic temperatures due to hydrogen's boiling point.

Ammonia, which is made up of hydrogen and nitrogen, may be a viable way to transport hydrogen as it is easier to liquify. New environmentally friendly techniques of producing hydrogen from ammonia have been developed and may provide for an easier path to a hydrogen fueled carbon-free future.

As the world continues its march towards zero-carbon emitting resources, hydrogen presents itself as a potential solution when produced from zero carbon emitting resources such as solar or wind. Existing high efficient gas turbines can burn small amounts of hydrogen, and newer turbines are being developed and tested that can burn 100% hydrogen as a fuel. The byproduct of burning hydrogen in such engines is water and heat, a zero-carbon footprint. NOx is a byproduct of burning any fuel and will still have to be dealt with as a pollutant.

Risk Consideration

Price: Storage and transportation must be cost competitive with alternate fuels.

Novelty: Creating carbon-free hydrogen is new on the radar, and testing is in the initial stages of execution.

Terrorism: Hydrogen is a very flammable gas and, as such, could be targets for terroristic plots.

Future of Hydrogen in Kentucky

Using hydrogen as a carbon-free surrogate fuel for gas is in the initial stages of development. It is a technology that will be continued to be monitored to ascertain its potential in portfolio development.



6.8 Hydroelectric Generation

The KYMEA AR Project members entered into agreements for KYMEA to integrate their entitlements to hydroelectric power from the Southeastern Power Administration (SEPA) as part of the AR Project power supply portfolio.

The SEPA entitlements are derived from nine hydroelectric plants of the U. S. Army Corps of Engineers’ Cumberland System of Projects located in Kentucky and Tennessee, which totals 927 MW of nameplate capacity. The first unit reached commercial operation in December 1948, and the newest unit reached commercial operation in November 1977. Service under the contracts commenced on May 1, 2019.



Southeastern Power Administration

Location: Kentucky and Tennessee

Type: Hydroelectric Power

History: The first unit reached commercial operation in December 1948, and the newest unit reached commercial operation in November 1977.

Member Generation Expiration: No expiration

Capacity: 32 MW

Southeastern Power Administration (SEPA)

The Southeastern Power Administration (SEPA) was founded in 1950 and is responsible for marketing electric power and energy generated at reservoirs operated by the United States Army Corps of Engineers. The electricity is marketed to utilities throughout the southeast United States. Kentucky greatly benefits from this extremely low cost power produced by SEPA facilities throughout the Commonwealth and received 6% of its energy from 9 hydroelectric dams shown in Figure 6.8-1.



Sustainable Sources of Power

HYDROELECTRICITY

The nine hydroelectric plants of the Cumberland River system consist of 28 generators with a total generating capacity of more than 914 megawatts. Power from these plants is sold at cost to KYMEA members through the Southeastern Power Administration.

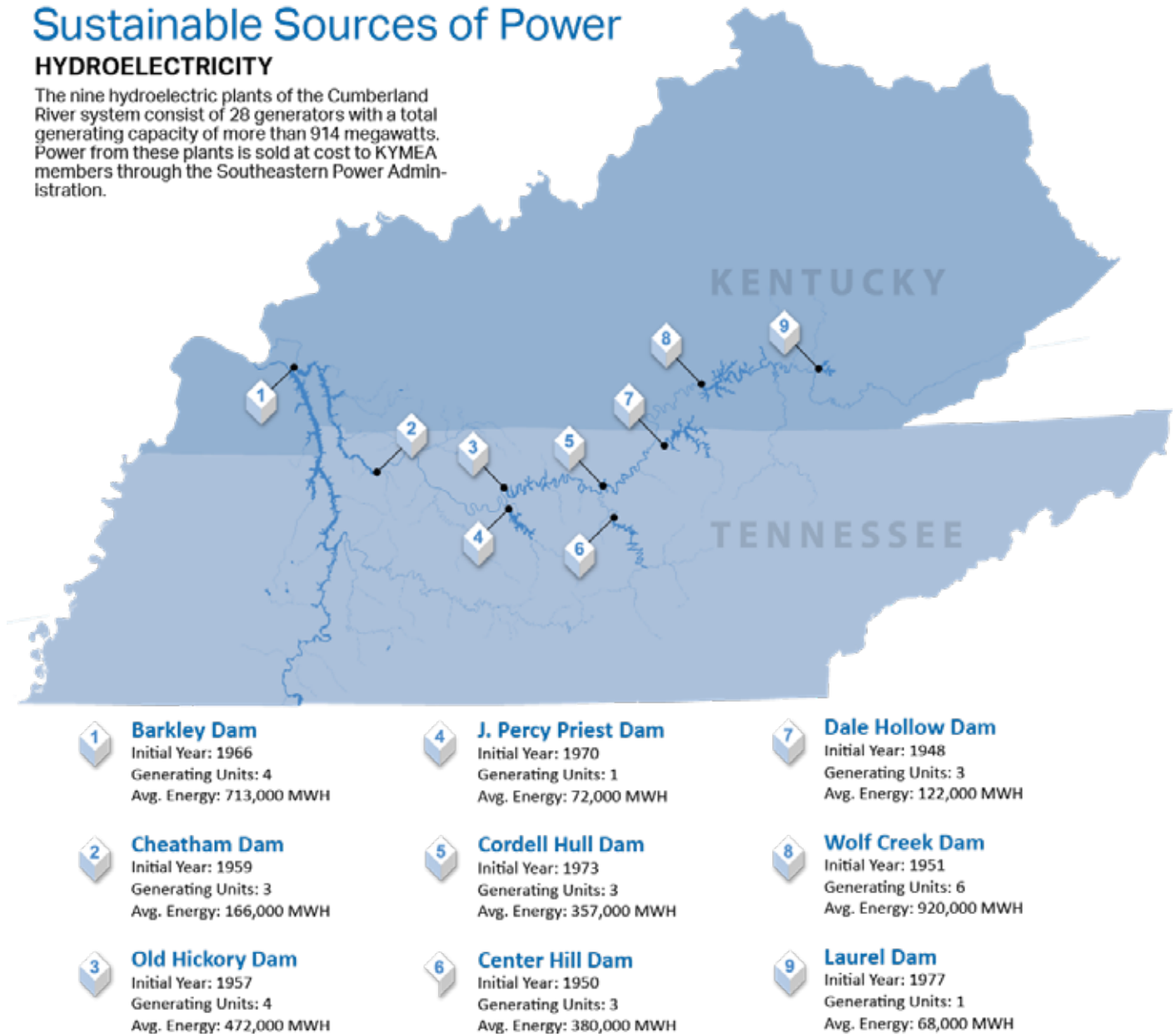


Figure 6.8-1: SEPA Cumberland River System Map



Overview

The U.S. has a long history of using the force of water flowing in streams and rivers to produce mechanical energy. This is due to hydropower being the U.S.'s most available, reliable, and sustainable energy resource. Hydropower was one of the first sources of energy used for electricity generation and, until 2019, it was the largest source of total annual U.S. renewable electricity generation. In 2020, hydropower was second only to wind as a renewable energy source and provided 7.3% of all electric generation in the U.S.⁴⁸

The proven reliability benefits of hydropower support other renewable energy technologies, stabilize the energy grid, and offer a way to store electricity for future use. It is not only a low cost renewable energy source, but it is among the least cost energy sources overall. As hydropower gets its fuel from waterways, it is not subject to volatile fuel commodity price fluctuations and can offer relative certainty about its operating costs. Hydropower has added benefits of providing flood control, navigation, irrigation, and water supply as well as recreational opportunities. These characteristics make hydropower an attractive power supply option.

Technology

Because the source of hydroelectric power is water, hydroelectric power plants are usually located on or near a water source. The volume of the water flow and the change in elevation—or fall, and often referred to as head—from one point to another determine the amount of available energy in moving water. In general, the greater the water flow and the higher the head, the more electricity a hydropower plant can produce.

At hydropower plants, water flows through a pipe, or penstock, then pushes against and turns blades in a turbine to spin a generator to produce electricity.

Conventional hydroelectric facilities include:

- Run-of-the-river systems, where the force of the river's current applies pressure on a turbine. The facilities may have a weir in the water course to divert water flow to hydro turbines.
- Storage systems, where water accumulates in reservoirs created by dams on streams and rivers and is released through hydro turbines as needed to generate electricity. Most U.S. hydropower facilities have dams and storage reservoirs depicted in Figure 6.8-2.

48

EIA. What is U.S. electricity generation by energy source? (2021, February). Retrieved April 21, 2021, from <https://www.eia.gov/tools/faqs/faq.php?id=427&unit=t=3>

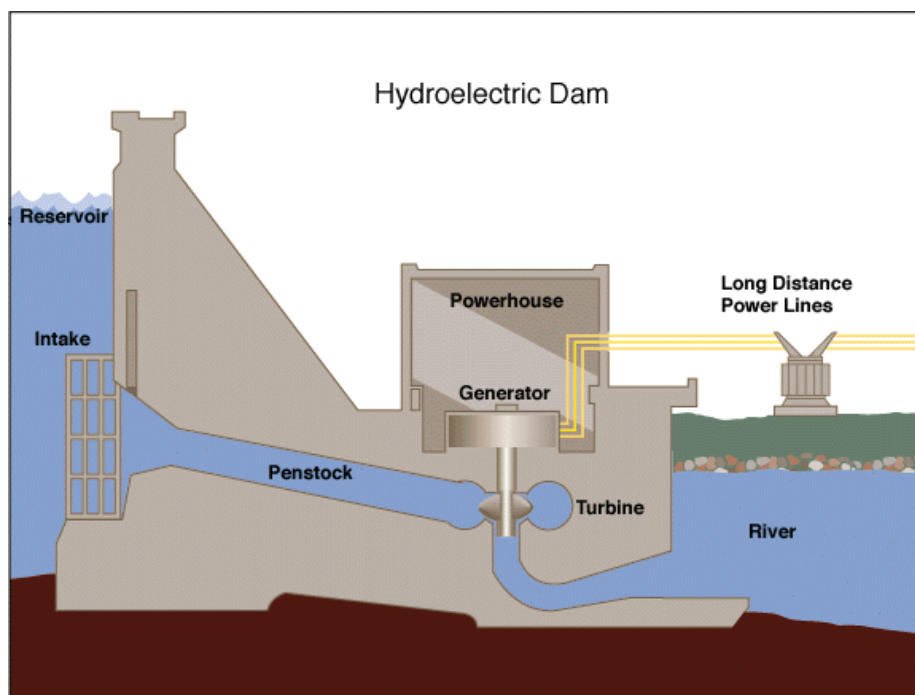


Figure 6.8-2: Illustration Hydroelectric Dam⁴⁹

Risk Considerations

Hydroelectric generation facilities have the benefits of a renewable, low cost energy resource; but they also come with risks. Damages to wildlife and its habitats, decreased water quality, obstructed fish migration, and decreased recreational benefits of some rivers need to be considered when assessing a hydropower site. Hydropower plants can also affect land as reservoirs are created covering homes and agricultural land.

While the ongoing fuel costs are low, initial costs to construct hydropower plants are high. These fixed costs are amortized over the life of the dam and represent the vast majority of the \$/MW cost to produce electricity.

Hydroelectric dams are extremely dependent on precipitation levels which vary from year to year. Both droughts and floods negatively affect the amount of energy these facilities can produce.

49

TVA. How hydroelectric power works. (n.d.). Retrieved April 22, 2021, from <https://www.tva.com/Energy/Our-Power-System/Hydroelectric/How-Hydroelectric-Power-Works>



Future of Hydropower in Kentucky

While the majority of hydroelectricity is produced in the western United States, as one can see from Figure 6.8-3, nearly every state has some form of hydropower facilities.



The 2020 National Hydropower Map

A Visualization of the Geospatial Distribution and Characteristics of Operational Hydropower Plants in the United States in 2020.

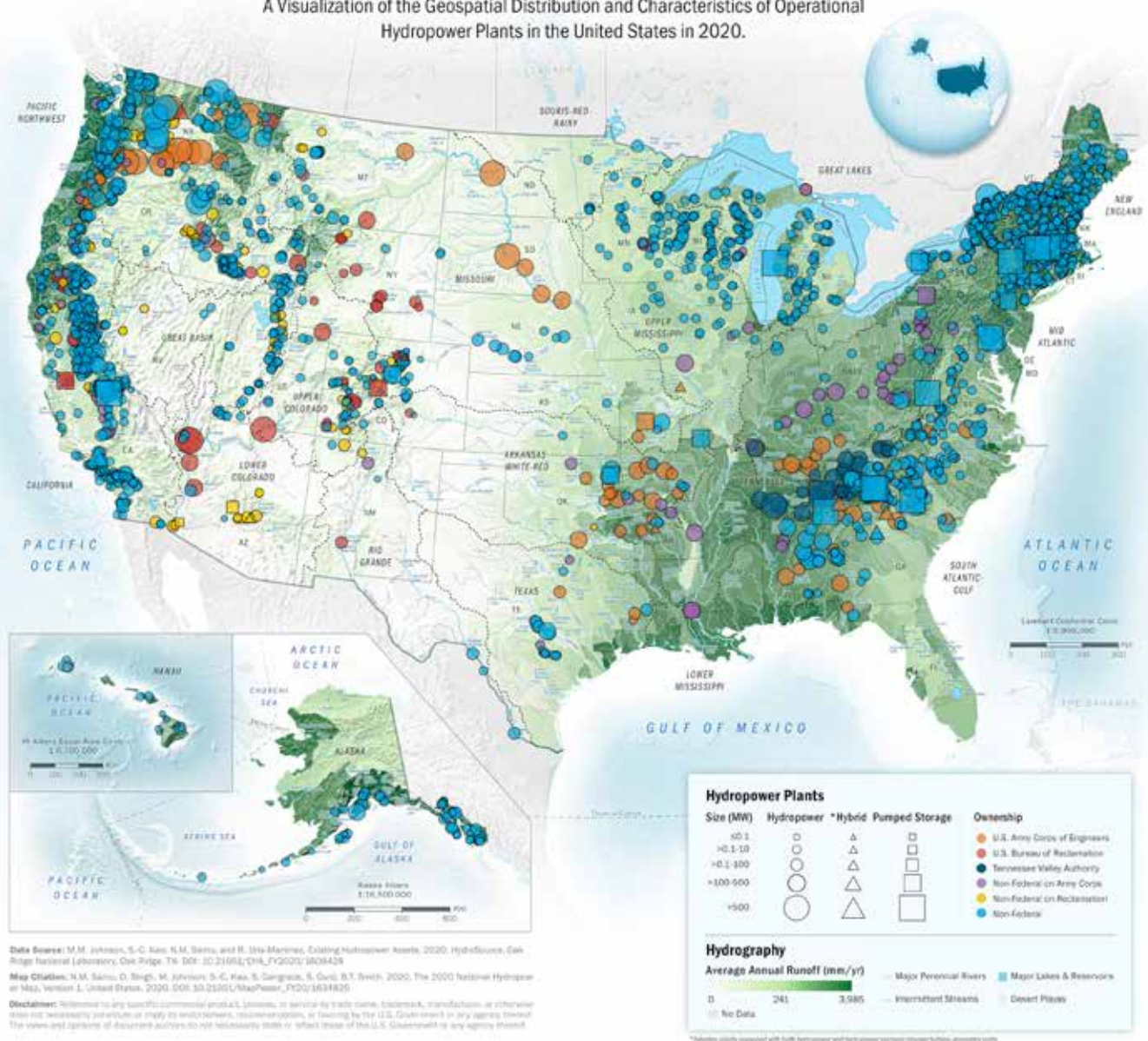


Figure 6.8-3: 2020 National Hydropower Map⁵⁰

50 Samu, N.M., D. Singh, M. Johnson, Kao, S.-C., Gangrade, S., Curd, S., and B.T. Smith. 2020. The 2020 National Hydropower Map. HydroSource. Oak Ridge National Laboratory, Oak Ridge, TN. DOI: 10.21951/NationalHydropowerMap_FY20/1634829



Figure 6.8-4 Shows the historical and projected U.S. hydro capacity projections from the Horizons Energy Spring 2020 Status Quo scenario.

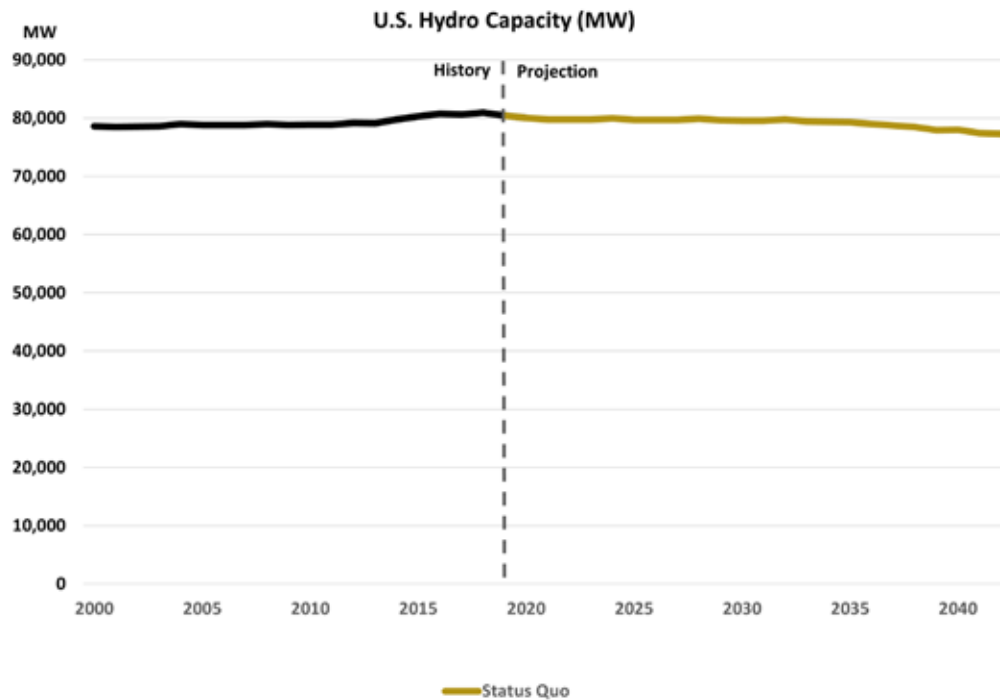
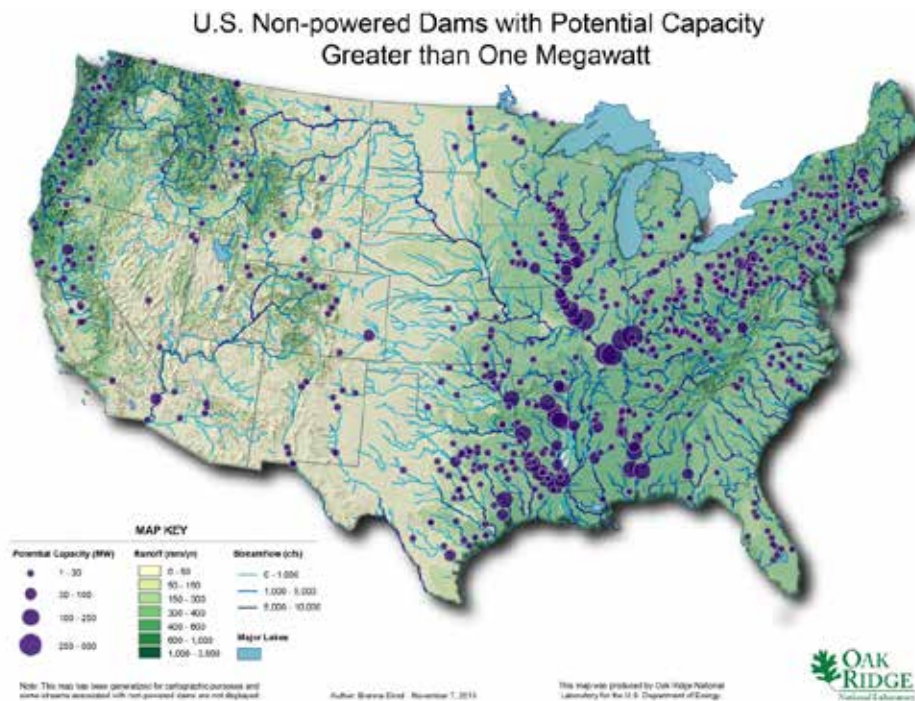


Figure 6.8-4: U.S. Hydropower Capacity (MW)

Figure 6.8-5 identifies potential new hydroelectric plants where a dam already exists.





6.9 Wind Generation

KYMEA does not currently have wind energy in its power supply portfolio.

Overview

From sailing, grinding grain, pumping water, and simply flying kites, mankind has harnessed the motion energy of wind throughout history. Using this motion energy to create electricity is no exception. As the world looks to further decarbonize its energy footprint, wind turbines will continue to be a part of the solution. Wind energy spins the rotor blades which, are connected to a generator via a driveshaft. The turning of the electric generator creates electricity. The spinning of the rotor blades is accomplished by lift and drag, much like an airplane wing. Different pressures across the rotor blades make the blades spin. There are two types of wind turbines, horizontal-axis (the most common) and vertical-axis. Horizontal-axis turbines pivot the rotor blades into the wind for maximum production; whereas, vertical-axis turbines are omnidirectional and do not require movement of the blades. Figure 6.9-1 shows a horizontal-axis wind turbine. Wind turbines are either land-based or offshore, and each is subject to permitting hurdles. The allure of offshore projects is that they have higher capacity rates than on-shore projects as they are able to harness the powerful ocean winds.

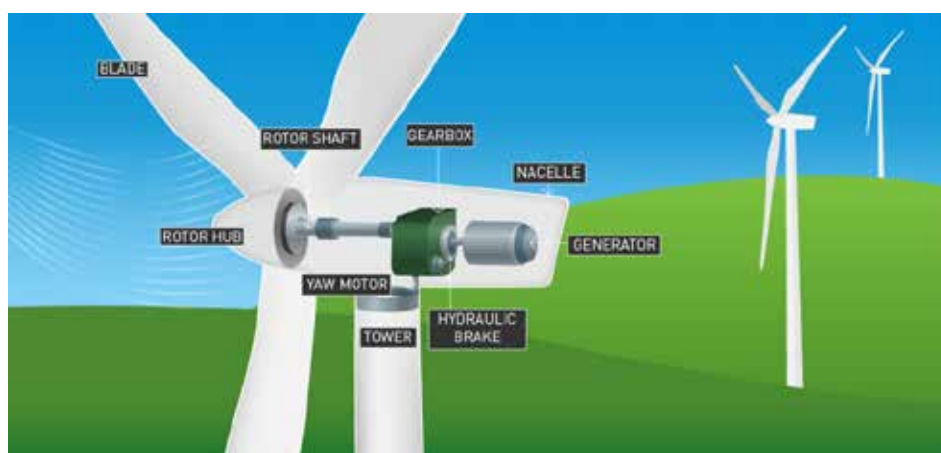


Figure 6.9-1: Illustration Wind Turbines⁵²

According to the EIA, 21 GW of wind capacity came online in 2020, bringing the total capacity of wind in the U.S. to 122 GW. The expectation is for another 12.2 GW to come online in 2021. The Traverse wind farm in Oklahoma (999 MW) is the largest project coming online in 2021. Dominion Energy's Coastal Virginia Offshore Wind (CVOW) pilot project is also slated to come on-line the same year. CVOW is comprised of two turbines totaling 12 MW off the coast of Virginia Beach.

Department of Energy, DC.

52 Innergex. How a wind turbine works [Digital image]. (n.d.). Retrieved April 22, 2021, from <https://www.innergex.com/energies/wind-energy/>



Figure 6.9-2 shows the projected U.S. wind capacity from the Horizons Energy Spring 2020 Status Quo scenario.

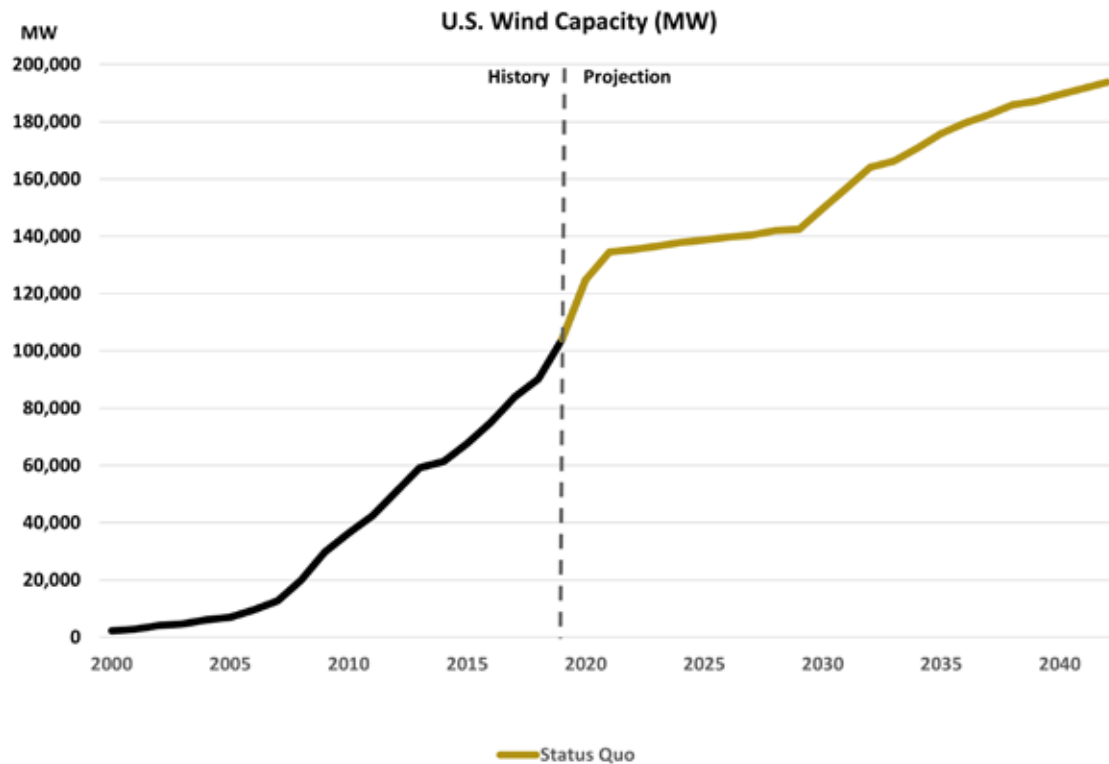


Figure 6.9-2: U.S. Wind Capacity (MW)

Production and Investment Tax Credits

Tax incentives have been a major driver of wind turbine installations in the U.S. The U.S. Production Tax Credit (PTC) was first enacted in 1992 and has been modified and extended since. The PTC is a credit for electricity generated by renewable resources and is computed on a per-kilowatt-hour basis for the first 10 years of operation. The credit is adjusted for inflation the year electricity is produced. Projects must enter service within four years of construction to qualify. Certain wind projects can make an irrevocable election to claim Investment Tax Credits (ITC) instead of PTC. The ITC is a benefit for more capital-intensive projects. The PTC was extended in 2019 as part of the Taxpayer Certainty and Disaster Relief Act of 2019. In May 2020, the IRS extended the four-year in-service deadline to five years for projects that began construction in 2016 or 2017 due to construction delays related to COVID-19.

The most recent extension was given as part of a stimulus bill in December 2020, when the PTC was set at 60% of the full credit or \$0.018 per kWh. In order to qualify for the extension, projects must begin construction by December 31, 2021. Off-shore wind projects can utilize a 30% ITC as part of the December 2020 stimulus bill. Under the ITC election, a project must begin construction prior to 2026, and it's not subject to any phase down.

Risk Considerations

Like any energy resource, wind comes with its own bundle of risks. Certain risks such as construction risk, financing, terrorism, etc., are not unique to a particular technology. Risks that are more unique to wind are:



Intermittency – Wind resource output is dependent upon its fuel source, the wind. This can create large variations in output from 0% up to 100%, and these variations must be balanced on a real-time basis. This risk can be mitigated by pairing wind projects with dispatchable resources.

Siting – Land-based projects are often developed in remote locations, increasing electric distances from resources to load. This can create pockets of congestion that can significantly impact the value proposition of a project. In order to mitigate this risk, transmission lines can be developed to deliver energy to the load centers. Land that is suitable for wind development must also compete with potentially more profitable uses of that land.

Pollution – Wind projects are not immune to pollution concerns; some of which are centered around noise and aesthetics. These risks can be greatly mitigated by siting the wind project in a remote location.

Environmental Impact – Birds and bats have been killed by spinning turbine blades. Wind projects can also potentially impact the suitability of habitats for other species. These risks have been reduced through technology developments and siting decisions.

Figure 6.9-3 illustrates the wind speed in the U.S. at 100 meters.

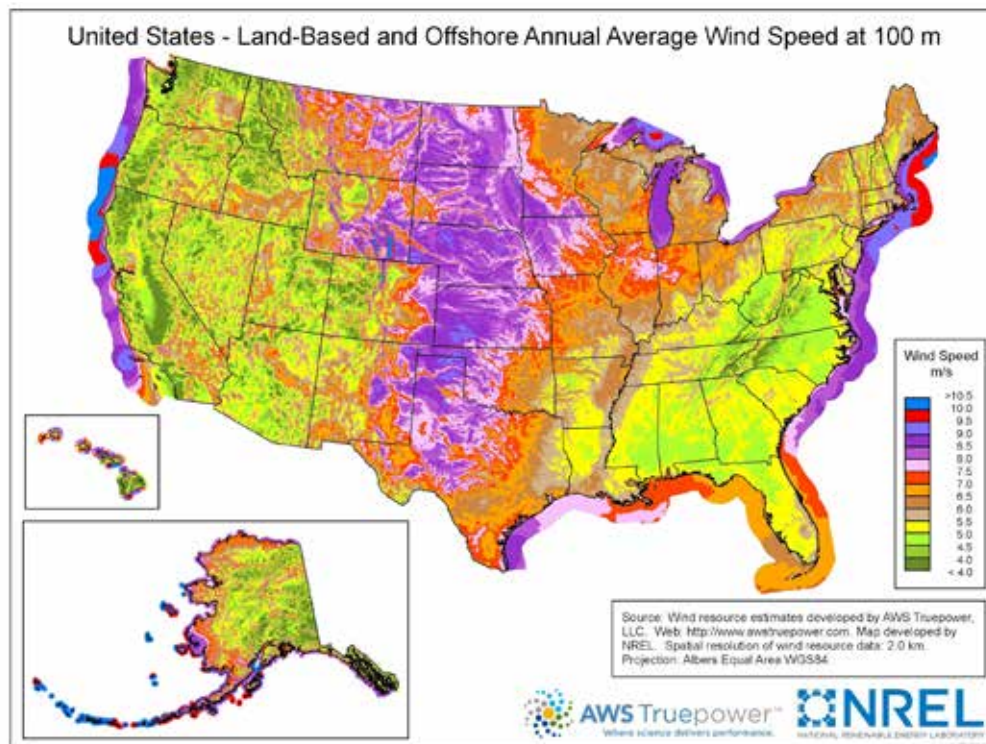


Figure 6.9-3: NREL U.S. Wind Prospector⁵³

Future of Wind in Kentucky

KYMEA did not receive proposals for wind projects in its RFP2020. In the development of the long-term plans, KYMEA assumed wind projects would be located in Indiana (MISO). Wind projects located in MISO require firm transmission to export the power into the LG&E/KU balancing authority. Given the electric distance and siting of these proposals, there exists significant congestion basis risk.

⁵³ NREL. United States - Land Based and Offshore Annual Average Wind Speed at 100 Meters [Digital image]. (n.d.). Retrieved April 22, 2021, from <https://www.energy.gov/eere/wind/downloads/united-states-land-based-and-offshore-annual-average-wind-speed-100-meters>



As shown in Figure 6.9-4, there is no wind generation installed in Kentucky.

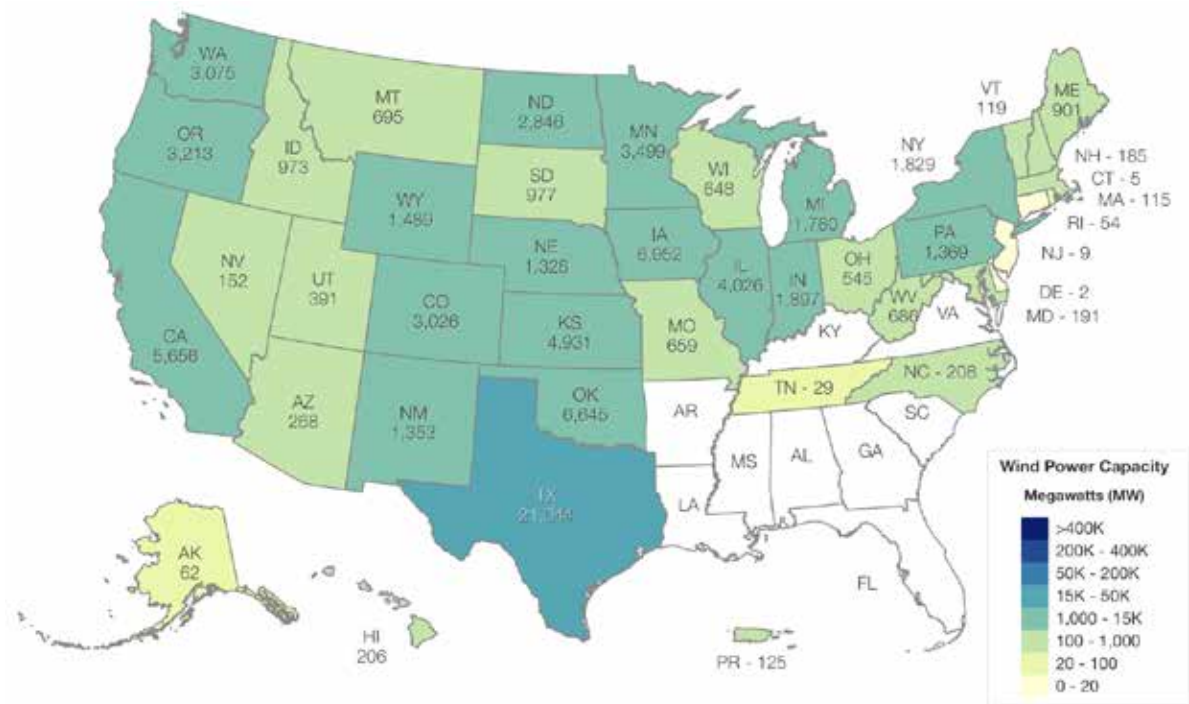


Figure 6.9-4: U.S. Wind Power Capacity⁵⁴

54 American Clean Power Association. (n.d.). U.S. Installed and Potential Wind Power Capacity and Generation [Digital image]. Retrieved April 22, 2021, from <https://windexchange.energy.gov/maps-data/321>



Kentucky Wind Potential

As illustrated by the NREL map in Figure 6.9-5, the U.S. land area, which currently sustains a stable wind supply at a capacity factor of greater than 30%, is highlighted by the dark blue area. With today's technology, wind is uneconomical in Kentucky due to the low-capacity factor in the southeast.

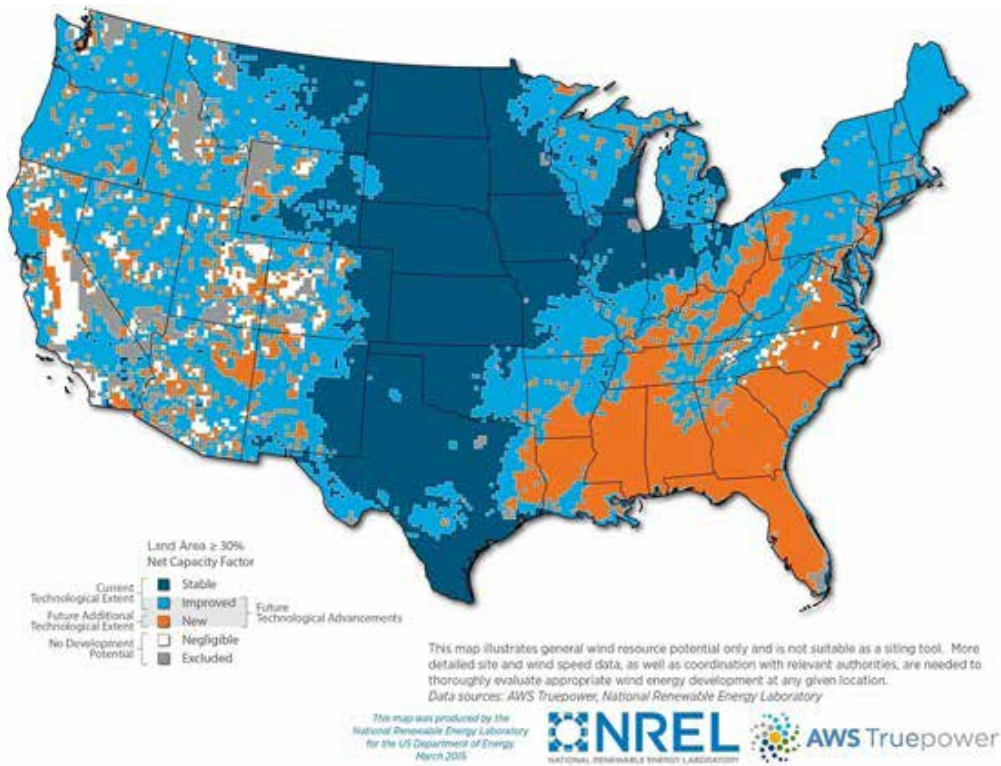


Figure 6.9-5: U.S. Wind Potential⁵⁵

55 NREL. (2015). U.S. Wind Potential. Enabling Wind Power Nationwide. <https://www.energy.gov/eere/wind/downloads/enabling-wind-power-nationwide>.



Wind Turbine Evolution

As wind technology grows in scale and productivity, researchers continue to look for ways to boost the energy captured while driving down costs.

The technological advancement of wind turbines to 140-meters can access stronger wind resources that exist at higher altitudes, beyond the reach of today's typical turbines. Taller wind turbine hubs also reduce interference from trees and buildings; and provides clearance necessary for longer blades, which increases energy capture per turbine.

In Kentucky, with taller wind turbine technology advancements, a 140-meter turbine has the potential for a higher gross capacity factor, as shown in Figure 6.9-6. Wind turbines of this height are rare in the U.S., but strides continue to be made to make them more cost-competitive and common place.

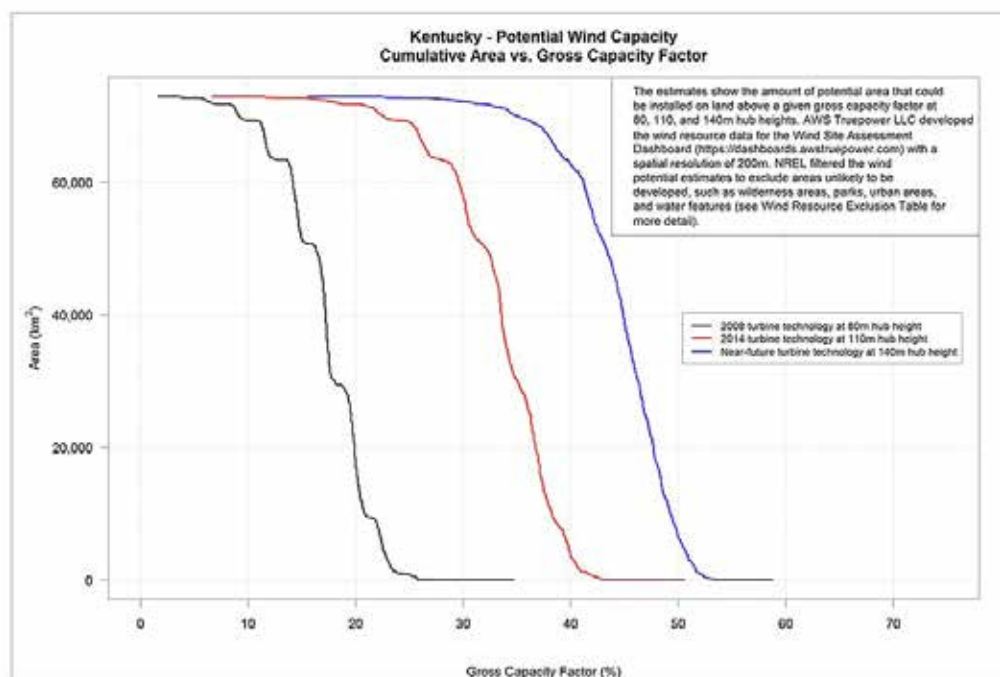


Figure 6.9-6: Kentucky Potential Wind Capacity



As wind technology progresses, it is expected that the hub height may be approaching 115 meters with an output of 3.25 MW in 2030, as illustrated in Figure 6.9-7. If hub heights approach 140 meters and wind costs continue to fall, it may be possible for economic wind in Kentucky by 2035. KYMEA will continue to monitor the cost and benefits of potential wind resources located within Kentucky.

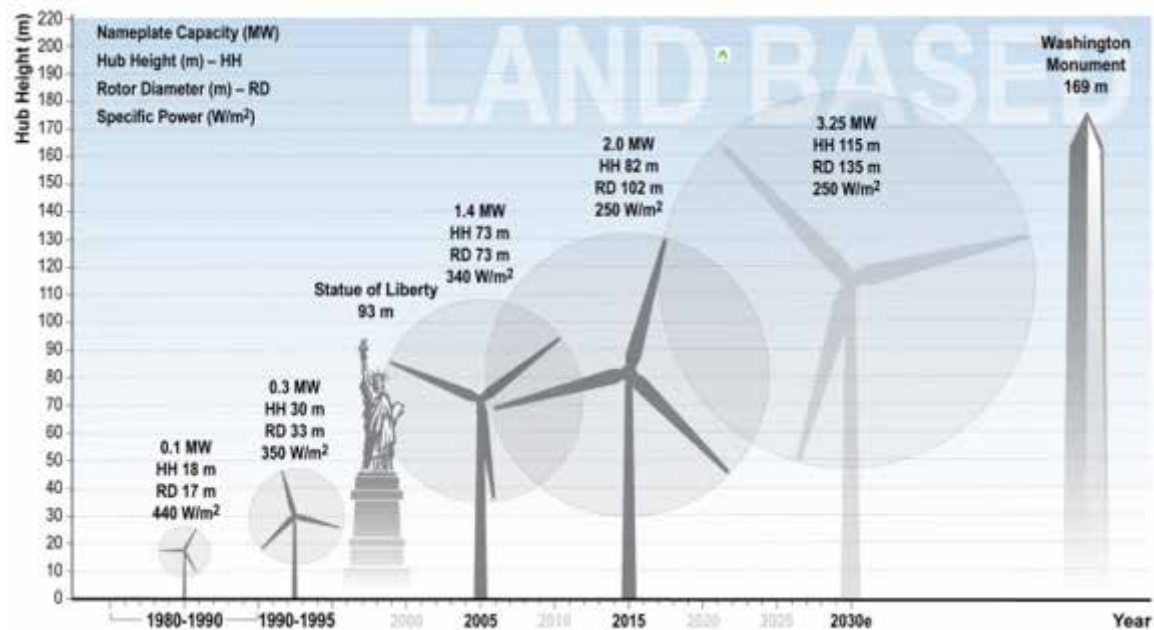


Figure 6.9-7: Wind Turbine Evolution in Land-Based Turbines⁵⁶

56 Berkeley Lab. (2016, November 1). Expected Growth in Land-Based Turbine Size in North America [Digital image]. Retrieved April 30, 2021, from <https://emp.lbl.gov/news/future-wind-energy-part-3-reducing-wind>



6.10 Utility-Scale Solar Generation

KYMEA entered into a twenty-year power supply contract for 53.75 MW of solar electric capacity and energy with Ashwood Solar I Project, an RWE Renewables Americas, LLC project.

Ashwood is developing an 86 MW single-axis tracking photovoltaic solar facility in western Kentucky. Service under the contract begins no later than December 1, 2022, or the facility's commercial operation date.

COMING ONLINE IN 2022

Ashwood Solar I Project

Location: Lyon & Caldwell counties, Kentucky

Site: Leases executed on 1,680 acres of previously disturbed agricultural parcels that are currently row cropped and have been in agricultural production for many years.

Technology: Bi-facial panels, single-axis tracker, central inverters

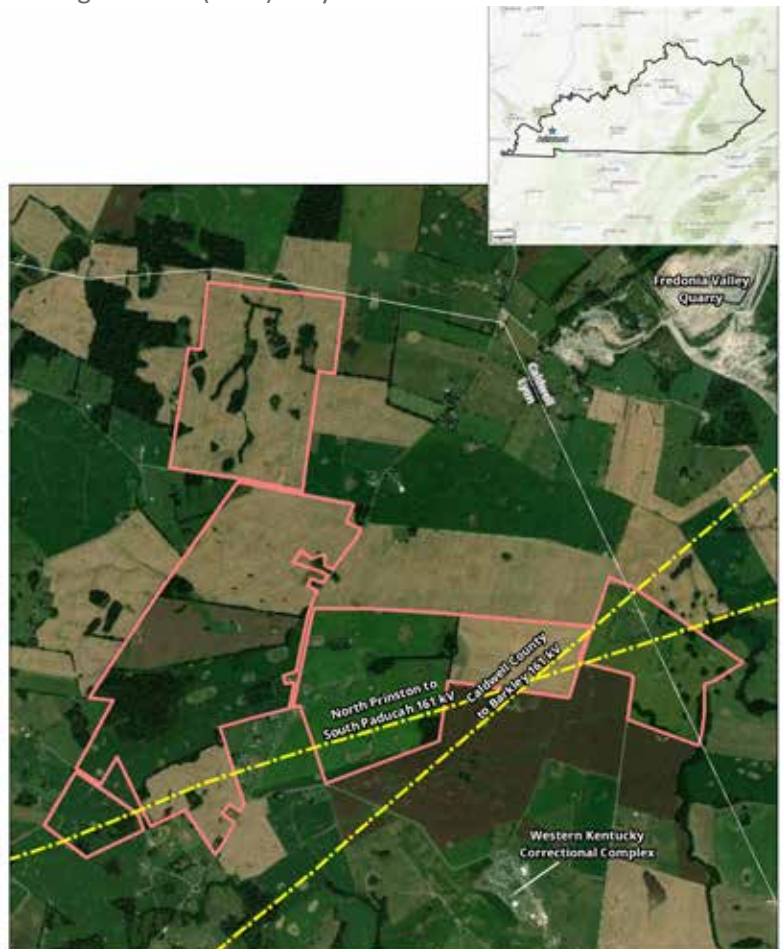
Balancing Authority: LG&E/KU

Interconnection Status: Large Generator Interconnection Agreement (LGIA) fully executed

PPA Expiration: December 2042

Target Notice To Proceed: January 2022

Target Commercial Operation Date: December 2022





Key Benefits

Renewable Energy: Ashwood will deliver clean, renewable energy for approximately 9% (54 MW) of the KYMEA load.

Direct Jobs: The project will create approximately 200-250 local construction jobs during the 9-to-12 month construction phase

Local Tax Revenue: The project will implement a local Industrial Revenue Bond (“IRB”) to ensure tax revenue flows to the local community.

Long Term Lease Revenue: The project will provide a stable income for up to 40 years to local Kentucky families participating in the project.

Indirect Impacts: The local community will benefit from the increased spending that will flow from construction activities to the local restaurants, gas stations, hotels, and other businesses.

Special Considerations

- RWE intends to use native seeding as part of its erosion control plan.
- A Decommissioning Bond will be put in place to ensure land is restored at the end of project life.
- RWE will pursue local partnerships with colleges and universities to support Science, Technology, Engineering, and Math (STEM) programs.





Overview

The sun has produced energy since the earth's creation and is the ultimate source for all energy sources and fuels that we use today. Over time, technologies have been developed to harness solar energy for heat and to convert it into electricity.

Solar power offers great promise as an energy source. The technology for reliably converting sunlight to electricity emerged from Bell Labs in the 1950s, but the expense of manufacturing photovoltaic, or PV, cells confined them to high-value uses such as remote radio transmission and the space program. As the price of silicon PV cells dropped dramatically, widespread use has emerged as people begin to utilize non-carbon energy alternatives.

According to the Solar Energy Industries Association (SEIA), U.S. solar companies installed 3.8 GW of new solar PV capacity in Q3 2020, a 9% increase from Q2 installations as the industry experienced a recovery from the worst impacts of the COVID-19 pandemic. According to the U.S. Solar Market Insight Q4 2020 report done by SEIA and Wood Mackenzie, solar accounts for 43% of all new electric generating capacity additions through Q3 2020, more than any other electricity source. Approximately 70% of installed capacity in that quarter was derived from the utility segment. The report also projects a record 19 GW of new solar capacity installations in 2020, marking a 43% year-over-year growth from 2019, and positioning it as the third-largest year ever. As a result of this progress, solar energy represents approximately 2.3% of energy production in the U.S. Figure 6.10-1 shows the projected U.S. solar capacity from the Horizons Energy Spring 2020 Status Quo scenario.

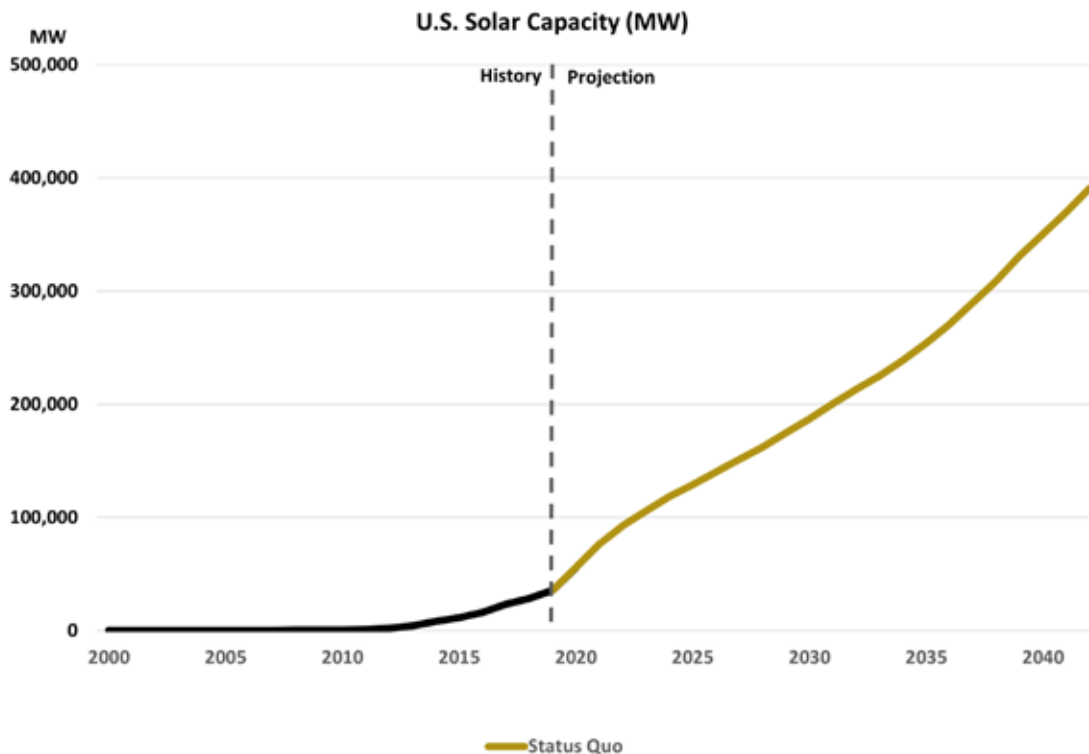


Figure 6.10-1: U.S. Solar Capacity (MW)



Figure 6.10-2 shows solar irradiance hot spots throughout the U.S.

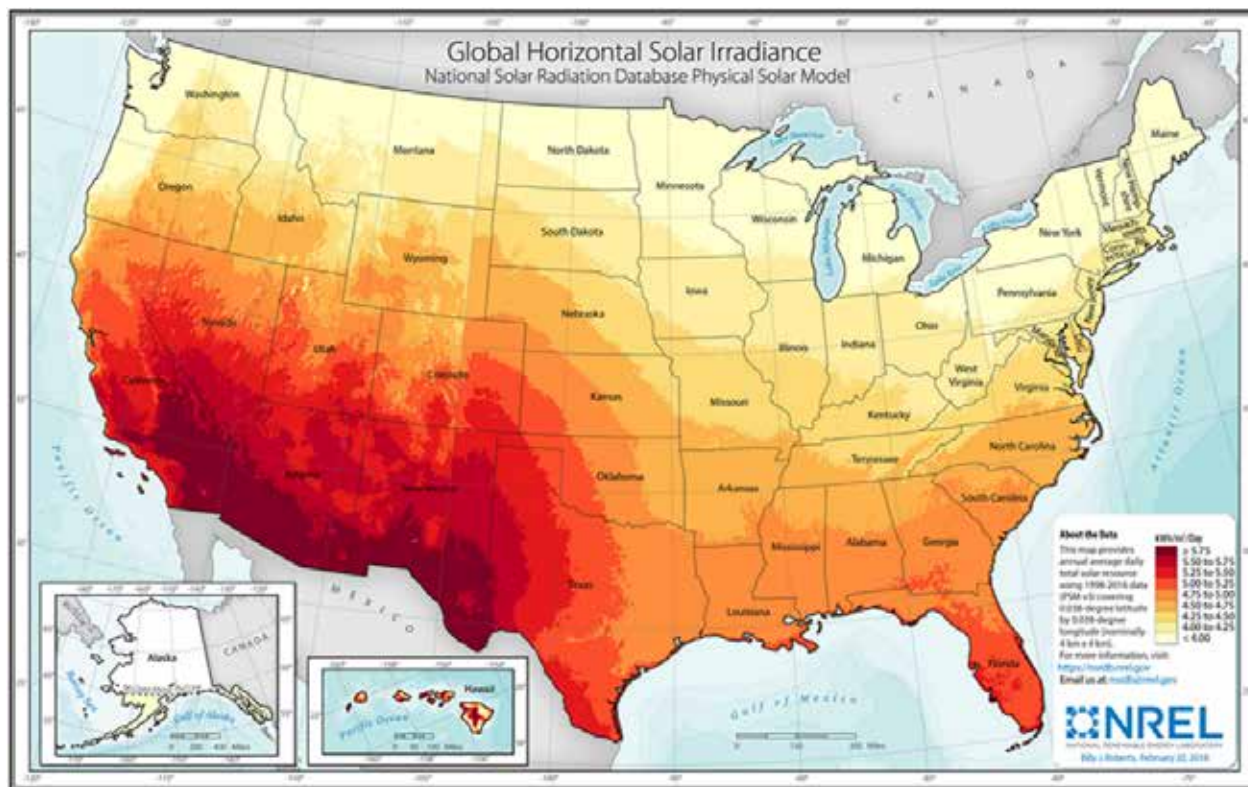


Figure 6.10-2: U.S. Horizontal Solar Irradiance⁵⁷

Pandemic Effects

Despite the coronavirus pandemic bringing with it increased financial risk and more challenging market conditions for developers, the utility solar market has survived these uncertainties and sustained growth. In fact, the 2020-2025 forecast has increased by 8.6 GWdc. This increase is due to 9.5 GWdc of new capacity installation announcements in the latter part of 2020, several utilities announcing carbon reduction and renewable energy targets, and increased confidence in project buildout.

The pandemic has caused virtually no delays in utility project construction. The pandemic has also caused little to no slowdown in new project announcements. By and large, utilities have continued ramping up solar procurement in anticipation of the ITC project completion deadline on December 31, 2023.

Despite the renewed confidence in the market, there are some risks. Insufficient tax equity financing for all projects is one concern. While this is a risk, it is possible that impacted projects will not see cancellations but incur delays instead. Developers continue to report increased difficulty securing engineering, procurement, and construction (EPC) contracts for projects. As the number of developers seeking construction firms to complete projects prior to 2024 rises, EPCs have been reported as increasingly selective regarding which projects they select. They tend to favor large firms over smaller companies with the hope of repeat business.

⁵⁷ NREL. (2018, February 22). Global Horizontal Solar Irradiance [Digital image]. Retrieved April 22, 2021, from <https://www.nrel.gov/gis/assets/images/solar-annual-ghi-2018-usa-scale-01.jpg>



Potential Impacts of the Election

While the Biden administration has signaled the intention to encourage more solar, there are numerous political uncertainties that render meaningful quantitative market analysis speculative at this point. Potential policies regarding tax credits, trade tariffs, decarbonization targets, and research and development spending could materially support solar market growth, but market outcomes cannot be forecasted without additional clarity regarding the scope of upcoming policy changes.

Investment Tax Credit

The impact of the solar investment tax credit (ITC) on the industry cannot be understated. The ITC is an extremely important federal policy mechanism to incentivize investment in solar generation. Since its implementation in 2006, the credit has propelled the solar industry to a growth rate of more than 10,000%, with an annual growth rate of 50% in the last decade. In the December 23, 2020 COVID-19 relief package, Congress passed a two-year delay in the ITC phasedown providing certainty to long-term investments by developers. The increased competition and innovation deriving from these investments support a decrease in solar energy products.

The ITC functions as a dollar-for-dollar reduction in income tax for taxable entities or individuals and is based on the investment in solar fixed assets. The credit provides a reduction of 26% for projects that begin construction in 2021 and 2022 and 22% for projects that begin construction in 2023, if they are placed in service prior to 2026. Figure 6.10-3 shows the residential credit drops to zero and the commercial credit to a permanent 10 for construction commenced 2024 or after.

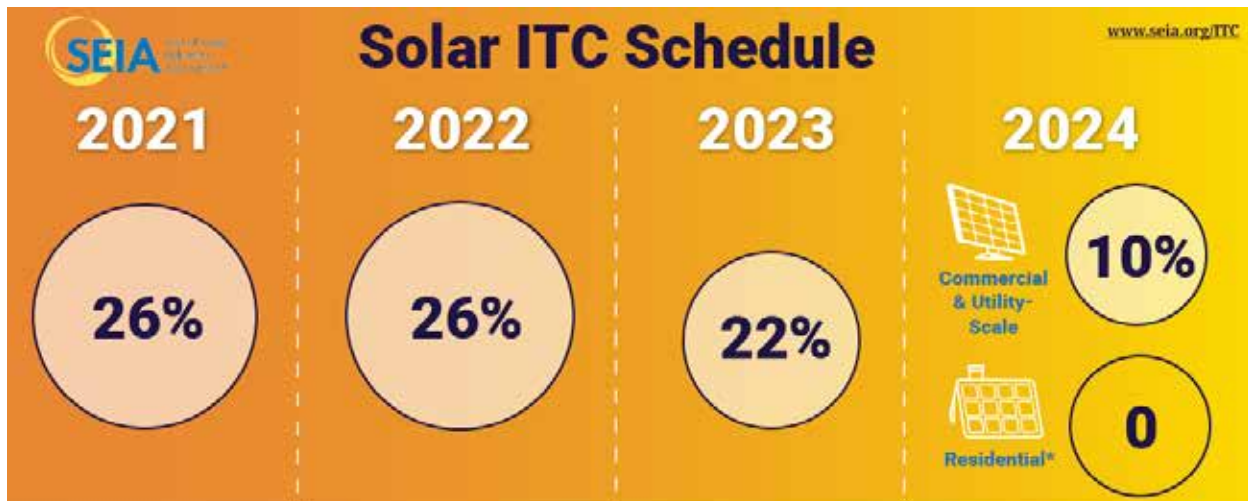


Figure 6.10-3: Solar ITC Schedule⁵⁸

58 SEIA. (n.d.). Solar ITC Schedule [Digital image]. Retrieved April 22, 2021, from <https://www.seia.org/initiatives/solar-investment-tax-credit-itc>



Risk Considerations

Solar energy, like all energy sources, does have some inherent risks associated with the construction and operation of the project. For example:

Construction risk: Risk of property damage or liability stemming from errors during the building of new projects.

Company risk: Risk affecting the viability of the project developer, for example, risks related to key personnel, financial health and technical ability.

Environmental risk: Risk of environmental damage caused by the solar park, including any liability following such damage.

Financial risk: Risk of insufficient access to investment and operating capital.

Market risk: Risk of cost increases for key input factors such as labor or modules, or rate decreases for electricity generated.

Operational risk: Risk of unscheduled plant closure due to the lack of resources, equipment damages or component failures.

Technology risk: Risk of components generating less electricity over time than forecasted.

Political and regulatory risk: Risk of a change in policy that may affect the profitability of the project, for example, changes in levels of tax credit or renewable portfolio standards (RPS) targets. Also, this includes changes in policy as related to permitting and interconnection.

Sabotage, terrorism, and theft risk: Risk that all or parts of the solar park will be subject to sabotage, terrorism, or theft and thus generate less electricity than planned

In addition to the risks above, solar contains climate and weather risks. The amount of sunlight that arrives at the earth's surface is not constant. The amount of sunlight varies depending on location, time of day, season of the year, and weather conditions. As a result, traditional energy sources or storage are required to produce energy when solar is not available.

The immediate impact of the presence of any of these risk factors is uncertainty around the revenue and profitability projections for the project and thus the financial viability of the project.

Many of the risks mentioned above can be managed through financial instruments and insurance products. For example, weather risks can be mitigated through weather futures, while technology risks can be offset through warranties. For a relatively young industry such as solar, a lack of engineering studies for actuarial purposes often means that financial risk management products are badly re-purposed from other fields and prohibitively priced.

Technologies: Solar Energy 101

A photovoltaic system converts the sun's radiation, in the form of light, into usable electricity. It comprises the solar array and the balance of system components. PV systems can be categorized by a number of aspects, such as grid-connected vs. stand-alone systems, building-integrated vs. rack-mounted systems, residential vs. utility systems, distributed vs. centralized systems, rooftop vs. ground-mounted systems, and tracking vs. fixed-tilt systems.

The building blocks of a photovoltaic system are solar cells. A solar cell is an electrical device that can convert photon energy into electricity. Conventional c-Si solar cells are encapsulated in a solar module to protect them from the weath-



er. The module consists of a tempered glass cover, a soft and flexible encapsulant, a rear backsheet made of a weathering and fire-resistant material and an aluminum frame around the outer edge. Electrically connected and mounted on a supporting structure, solar modules build a string of modules, often called solar panel. A solar array consists of one or many such panels. A photovoltaic array, or solar array, is a linked collection of solar modules. The power that one module can produce is seldom enough to meet the requirements of a home or a business, so the modules are linked together to form an array.

Module and Efficiency

A typical 150 watt PV module is about a square meter in size. Such a module may provide 0.75 kilowatt-hours (kWh) every day, on average, allowing for weather and the latitude, for an insolation of 5 sun hours/day. Module output and life is degraded by increased temperature. Allowing air to flow over, and if possible behind, PV modules aids in mitigating this problem. Module asset lives are 25 years or more. While the return on investment in a PV solar installation can be estimated to be between 10 and 20 years, the financial payback period can be far shorter with incentives.

Due to the low voltage of an individual solar cell (typically ca. 0.5V), several cells are used in series in the manufacture of a “laminated.” The laminate is assembled within a protective weatherproof enclosure, thus making a photovoltaic module or solar panel. Modules may then be strung together into a photovoltaic array.

Shading and Dirt

Photovoltaic cell energy output is very sensitive to shading. When even a small portion of a cell, module, or array is shaded, the output falls substantially due to internal “short-circuiting.” Several methods have been developed to determine shading losses from trees on PV systems. Most modules have bypass diodes between each cell or string of cells that minimize the effects of shading and only lose the power of the shaded portion of the array. The main job of the bypass diode is to eliminate hot spots that form on cells that can cause further damage to the array and cause fires.

Sunlight can be absorbed by dust, snow, or other impurities at the surface of the module. This is known as soiling. Soiling reduces the light that strikes the cells, which in turn reduces the power output of the PV system. Soiling losses aggregate over time and can become large without adequate cleaning. In 2018, the global annual energy loss due to soiling was estimated to at least 3 % - 4 %; however, soiling losses vary largely from region to region and within regions. Maintaining a clean module surface will increase output performance over the life of the PV system. In one study performed in a snow-rich area in Canada, cleaning flat mounted solar panels after 15 months increased their output by almost 100%; however, 5° tilted arrays were adequately cleaned by rain.

Insolation and Energy

Solar insolation is made up of direct, diffuse, and reflected radiation. The absorption factor of a PV cell is defined as the fraction of incident solar irradiance that is absorbed by the cell. At high noon on a cloudless day at the equator, the power of the sun is about 1 kW/m², on the earth’s surface, to a plane that is perpendicular to the sun’s rays. As such, PV arrays can track the sun through each day to greatly enhance the energy collection area. However, tracking devices add cost and require maintenance. It is more common for PV arrays to have fixed mounts that tilt the array and face solar noon. The tilt angle, from horizontal, can be varied for the season, but if fixed, it should be set to give optimal array output during the peak electrical demand portion of a typical year. This optimal module tilt angle is not necessarily identical to the tilt angle for maximum annual array energy output. The optimization of the photovoltaic system for a specific environment can be complicated as issues of solar flux, soiling, and snow losses should be taken into effect. In addition, later work has shown that spectral effects can play a role in optimal photovoltaic material selection. For the weather and latitudes of the United States, typical insolation ranges from 4 kWh/m²/day in northern climes to 6.5 kWh/m²/day in the sunniest regions. A photovoltaic installation in the northern latitudes of the United States may expect to produce 1 kWh/m²/day. A typical 1 kW photovoltaic installation in the southern latitudes of the United States, may produce 3.5–5 kWh per day, dependent on location, orientation, tilt, insolation, and other factors.



Tracker

A solar tracking system tilts a solar panel throughout the day. Depending on the type of tracking system, the panel is either aimed directly at the sun or the brightest area of a partly cloudy sky. Trackers greatly enhance early morning and late afternoon performance, increasing the total amount of power produced by a system by about 20–25% for a single axis tracker and about 30% or more for a dual-axis tracker, depending on latitude. Trackers are effective in regions that receive a large portion of sunlight directly. In diffused light from clouds or fog, tracking has little or no value. Most concentrated photovoltaics systems are very sensitive to the sunlight's angle; therefore, tracking systems allow them to produce useful power for more than a brief period each day. Tracking systems improve performance for two main reasons:

- When a solar panel is perpendicular to the sunlight, it receives more light on its surface than if it were angled; and
- Direct light is used more efficiently than angled light.

Special anti-reflective coatings can improve solar panel efficiency for direct and angled light, somewhat reducing the benefit of tracking. Trackers and sensors can increase viable output by up to 45%. As pricing, reliability, and performance of single-axis trackers have improved, the systems have been installed in an increasing percentage of utility-scale projects. Figure 6.10-4 outlines the solar panel parameters that affect bifacial gain and efficiency.

Component	Parameters affecting Bifacial Gain
 Solar Module	Cell Type
	Module Technology
	Bifaciality
 Tracker	Orientation
	GCR
	Clearance/Height
 Albedo REFLECTION	Smart Capture
	Natural
	Artificial
 Electrical	Location/Weather
	DC/AC
	Capacity Test

Figure 6.10-4: Parameters Affecting Bifacial Production - RWE⁵⁹

Future of Solar in Kentucky

Compared to other markets around the U.S. solar industry, Kentucky's solar irradiance is slightly below average. Solar systems have power ratings in watts. On an annual basis, a typical system in Kentucky will produce 1.3 kWh per watt as compared to 1.6 kWh per watt in San Antonio, Texas or 1.8 kWh⁶⁰ per watt in Tucson, Arizona. Similar systems in the northeast U.S. produce between 1.2 – 1.5 kWh per watt. As of Q3 2020, Kentucky ranked 48th in installed solar power in the U.S. with only 0.15% of the state's electricity derived from solar facilities. It is projected to add 676 MW over the next 5 years.⁶¹

59 RWE. Ashwood Solar I Solar & Energy Storage Technology Overview Presentation, June 24, IRP2020 Community Focus Group

60 Does Solar Power Really Work In Kentucky? (2018, July 26). Retrieved April 22, 2021, from <https://purepowersolar.net/2018/07/26/solar-power-in-kentucky/>

61 SEIA. (2020, December). Kentucky Solar. Retrieved April 22, 2021, from <https://www.seia.org/state-solar-policy/kentucky-solar>



6.11 Battery Storage

KYMEA does not currently have any battery storage in its power supply portfolio.

Overview

Battery storage technology is often heralded as the solution lurking just around the bend which is going to solve all electric grid issues. As solar and wind generation are not available all the time and do not sync up perfectly with electricity demand, the easy solution for bringing a significant level of adaptation to renewable energy sources seems to be inexpensive energy storage. In many parts of the country, the cost of energy from renewable technologies closely matches the cost level of fossil-fuel production. Available, inexpensive batteries would seem to be the answer for those who desire a 100% renewable grid that maintains flexibility and reliability.

Big venture capitalists, global corporations, and very high net worth individuals are betting on the potential of new innovative battery chemistries and storage systems to the tune of hundreds of millions of dollars. Governments are putting large incentive programs into place to encourage battery deployment onto the electric grid. Battery technology is definitely on everyone's radar, and it provides much promise for the energy industry's future.

Batteries can provide arbitrage opportunities by charging the battery when energy prices are low and discharging during more expensive peak hours. Done correctly, this can provide a source of income by taking advantage of variable electricity prices. Arbitrage can also be applied to renewable energy curtailment. By charging the battery with electricity during periods of excess renewable generation and discharging during periods of high demand, battery storage systems can both reduce renewable energy curtailment and maximize the value of the energy. This also allows operators to more efficiently coordinate the dispatch of generating resources.

Utilities must ensure they have an adequate supply of generation capacity to reliably meet demand during peak demand periods. This demand is typically met with higher-cost generators; but, depending on the shape of the load curve, batteries can be utilized to provide adequate peaking generating capacity.

Utilities must also balance the electric grid to maintain reliable power system operations. In other words, electricity generation must exactly match demand. Battery storage can quickly charge or discharge in a fraction of a second and provide near-term reliability service and regulation. Battery storage systems can also provide services such as load-following and ramping services to balance the system.

The electricity grid's transmission and distribution infrastructure must be sized to meet peak demand, but this amount of energy is only needed in rare hours throughout a year. As this peak demand grows and exceeds the existing grid's capacity, expensive capital outlays are necessary to upgrade equipment and develop new infrastructure. Batteries may help postpone the need for new grid investments by meeting peak demand with energy stored from lower-demand periods. This also reduces congestion and improves overall transmission and distribution asset utilization.

As large generators start up, there is a need for an external source of electricity to perform key functions before they can begin generating electricity. In normal system conditions, this external power can be provided by the grid, but subsequent to a system failure, the grid may not be able to provide this power, and generators use an alternate source of electricity to perform what is known as black start. Battery storage systems can provide this service and alleviate fuel costs and emissions from fossil-fueled black-start generators.

How much grid-scale battery storage a system needs depends on several system-specific characteristics such as generation technologies in the present system, flexibility available in these existing generation sources, interconnections with neighboring power systems, and the hourly, daily, and seasonal profile of electricity demand which the system serves.



Technology

Battery storage empowers power system operators and utilities to store energy for later use when it is needed for customer demand. A battery energy storage system (BESS) is an electrochemical device that charges from the grid, a fossil-fuel energy plant, or a renewable power plant and then discharges that energy later to provide electricity. Several different battery chemistries are available or being studied for grid-scale applications, including lithium-ion, lead-acid, redox flow, and molten. Battery chemistries differ in key technical aspects, and each technology has advantages and disadvantages. Lithium-ion chemistries account for the majority of the current market for grid-scale battery storage in the U.S. at the present time. Price decreases in battery storage have been steep over the past decade due to technological innovations and improved manufacturing capacity, and price decreases are anticipated to continue throughout the current decade.

All battery storage systems have important aspects to consider:

- Rated power capacity is the total possible instantaneous discharge capability (MW).
- Energy capacity is the maximum amount of stored energy (MWh).
- Storage duration is the amount of time storage can discharge at its power capacity before depleting its energy capacity. For example, a battery with 1 MW of power capacity and 4 MWh of usable energy capacity will have a storage duration of four hours.
- Cycle life is the number of times or cycles, a battery storage system can provide regular charging and discharging before it must be replaced with a new facility. Additionally, certain battery chemistries, like lithium-ion, will have a longer operating life if not fully discharged during each charge/discharge cycle.
- Self-discharge is when the stored charge of the battery is reduced through internal chemical reactions without performing work for the customer. Self-discharge, expressed as a percentage of charge lost over a certain period, reduces the amount of energy available for discharge. It is an important characteristic to consider in batteries intended for longer-duration applications.
- Round-trip efficiency, measured as a percentage, is a ratio of the energy charged to the battery to the energy discharged from the battery. It can represent the total efficiency of the battery system, including losses from self-discharge and other electrical losses. Battery manufacturers commonly refer to the DC-DC efficiency, whereas AC-AC efficiency is more important to utilities.



Figure 6.11-1: Utility Scale Battery Storage Example⁶²

Risk Considerations

Despite all the promise which battery storage technology offers, it does have some risks to consider. Some researchers have concluded that battery storage has the risk of increased carbon emissions. Batteries do not generate power; they simply shift when power generated from other sources is used to meet demand. With each cycle of charging and discharging electricity, there is a loss of energy caused by the round-trip efficiency and some amount of self-discharge occurs. If a battery is being charged from a grid comprised of both fossil fuel and renewable generation, each cycle leads to a loss of electricity, and increases the amount of generation needed (energy plus losses) to meet load; thus the amount of fossil fueled generation is increased and emissions may increase.

Further, baseload power generation is generally coal based and the most inexpensive electricity. It follows that batteries tied to the generation grid will charge during these low-priced periods. The same batteries will discharge during high energy price periods to off-set peak power usually made up of gas or solar produced energy. The net result increases reliance on coal-fired plants, which emit the most emissions and reduces gas and solar reliance.

On the safety front, lithium-ion batteries are safe for the most part, but they have been linked to fire, explosion, and hazardous material exposure under certain conditions. In April 2019, an explosion at a 2.16 MWh lithium-ion battery storage site in Arizona, woke the energy industry to these risks. These batteries have flammable chemical electrolytes and can experience thermal runaway if the battery has faults or experiences stresses. Lithium-ion batteries can spontaneously reignite hours or even days after an explosion if cells go into this thermal runaway. This makes decommissioning, deconstructing, and storing a complicated task. Safety requirements for battery storage sites continue to be developed.⁶³

These concepts show the need for thoughtful battery deployment in the energy grid. Battery storage is a complicated issue and not as cut and dry as many propose.

62 Energy Source & Distribution. (2021, January 14). Utility Scale Battery Storage Example [Digital image]. Retrieved April 22, 2021, from <https://esdnews.com.au/agl-announces-suppliers-for-grid-scale-battery-plans/>

63 Kerber, S. (2020, September 28). 6 practical steps to improve community safety near LITHIUM-ION energy storage systems. Retrieved April 22, 2021, from <https://www.utilitydive.com/news/6-practical-steps-to-improve-community-safety-near-lithium-ion-energy-storage/585938/>

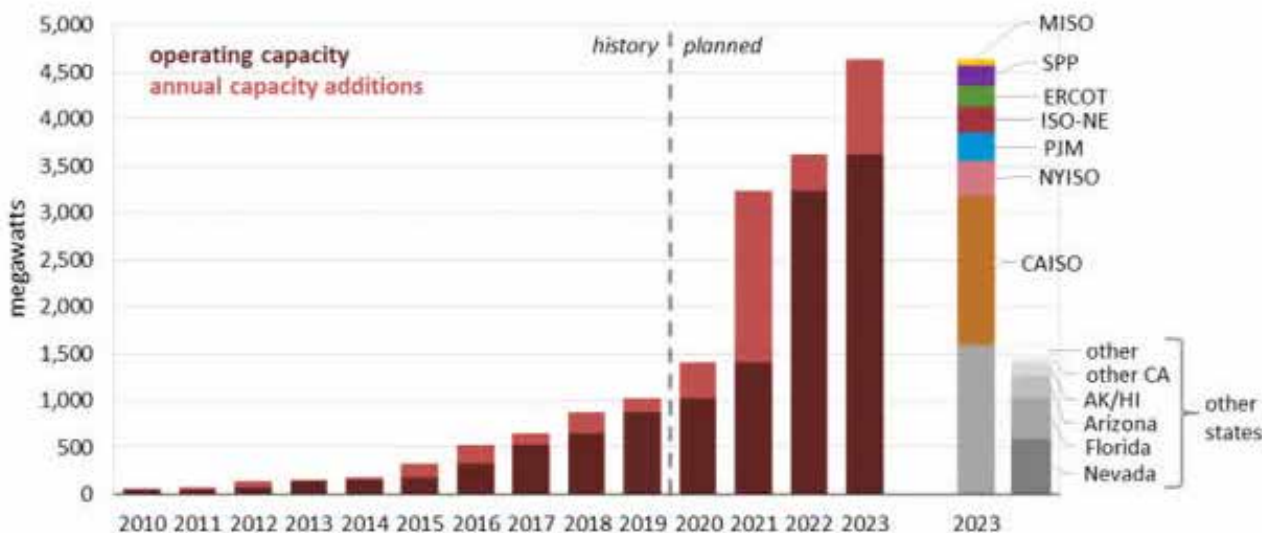


The majority of battery storage is installed in areas supported by Independent System Operators (ISO) or Regional Transmission Organizations, with PJM Interconnection and the California ISO having the most. These areas combine to have 55% of the total battery storage capacity constructed between 2010 – 2018. Other areas in the U.S. played catch-up in 2018 and added 130 MW that year, comprising 58% of new additions.

Future of Battery Storage in Kentucky

Large-scale battery storage systems are increasingly present across the U.S. power grid. Figure 6.11-2 shows that growth is happening at an exponential rate, evolving from 7 battery storage systems with 59 MW in 2010, to 49 systems containing 351 MW in 2015, to 125 sites in 2018, providing 869 MW of power capacity. The trend explodes with even greater intensity in the forecast for subsequent years.

Battery storage technologies are feasible for Kentucky. They will need to be monitored for continued development and pricing as well as evaluated against alternate solutions.



Source: U.S. Energy Information Administration, Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*

Figure 6.11-2: U.S. Large-Scale Battery Storage Cumulative Power Capacity (2010-2023)⁶⁴

Long Duration Battery Storage – Pilot Project

On May 7, 2020, Form Energy and Great Rivers Energy announced a partnership to develop an ultra-low-cost, long-duration storage project for a 1 MW / 150 MWh pilot project. The purpose of the pilot is to attempt to develop a grid-connected storage system capable of delivering its rated power continuously for 150 hours, far longer than the two-to-four-hour usage period common among lithium-ion batteries being deployed at utility-scale today. This duration allows for a fundamentally new reliability function to be provided to the grid from storage, one historically only available from thermal generation resources.

⁶⁴ Su, Yang-Duan & Preger, Yuliya & Burroughs, Hannah & Sun, Chenhu & Ohodnicki, P.R.. (2021). Fiber Optic Sensing Technologies for Battery Management Systems and Energy Storage Applications. *Sensors*. 21. 1397. 10.3390/s21041397.



6.12 Other Energy Storage

KYMEA does not currently have energy storage in its power supply portfolio.

In addition to battery storage discussed in the previous section, hydroelectric pumped storage, compressed air energy storage, and flywheels are the other existing utility-scale storage capacity in the United States. Hydroelectric pumped storage is far and away the most widespread and least expensive, with nearly 19 GW at various locations across the nation, as shown in Figure 6.12-1. This section also describes a new technology, concrete block storage, which works on the principle of kinetic energy.

Distribution of energy storage and other renewable power plants in the Lower 48 states

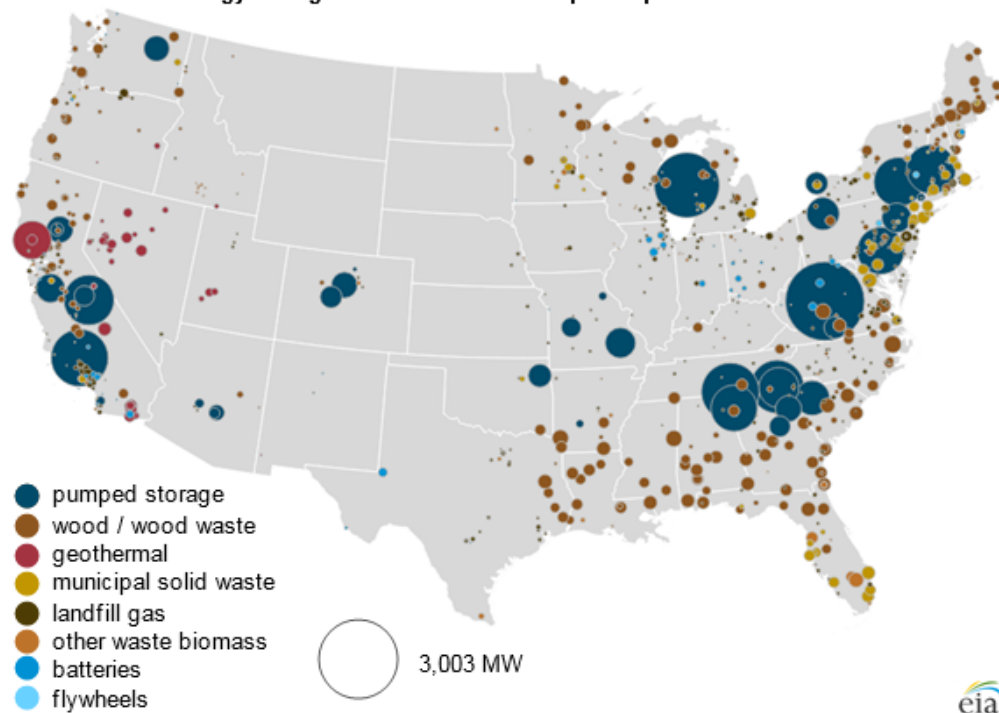


Figure 6.12-1: Distribution of Energy Storage and other Renewable Power Plants in Lower 48 States⁶⁵

⁶⁵ EIA. (2017, May 25). Energy storage and renewables beyond wind, hydro, solar make up 4% of U.S. power capacity. Retrieved April 22, 2021, from <https://www.eia.gov/todayinenergy/detail.php?id=31372>



Figure 6.12-2 highlights utility-scale energy storage projects throughout the U.S. as of December 4, 2020.

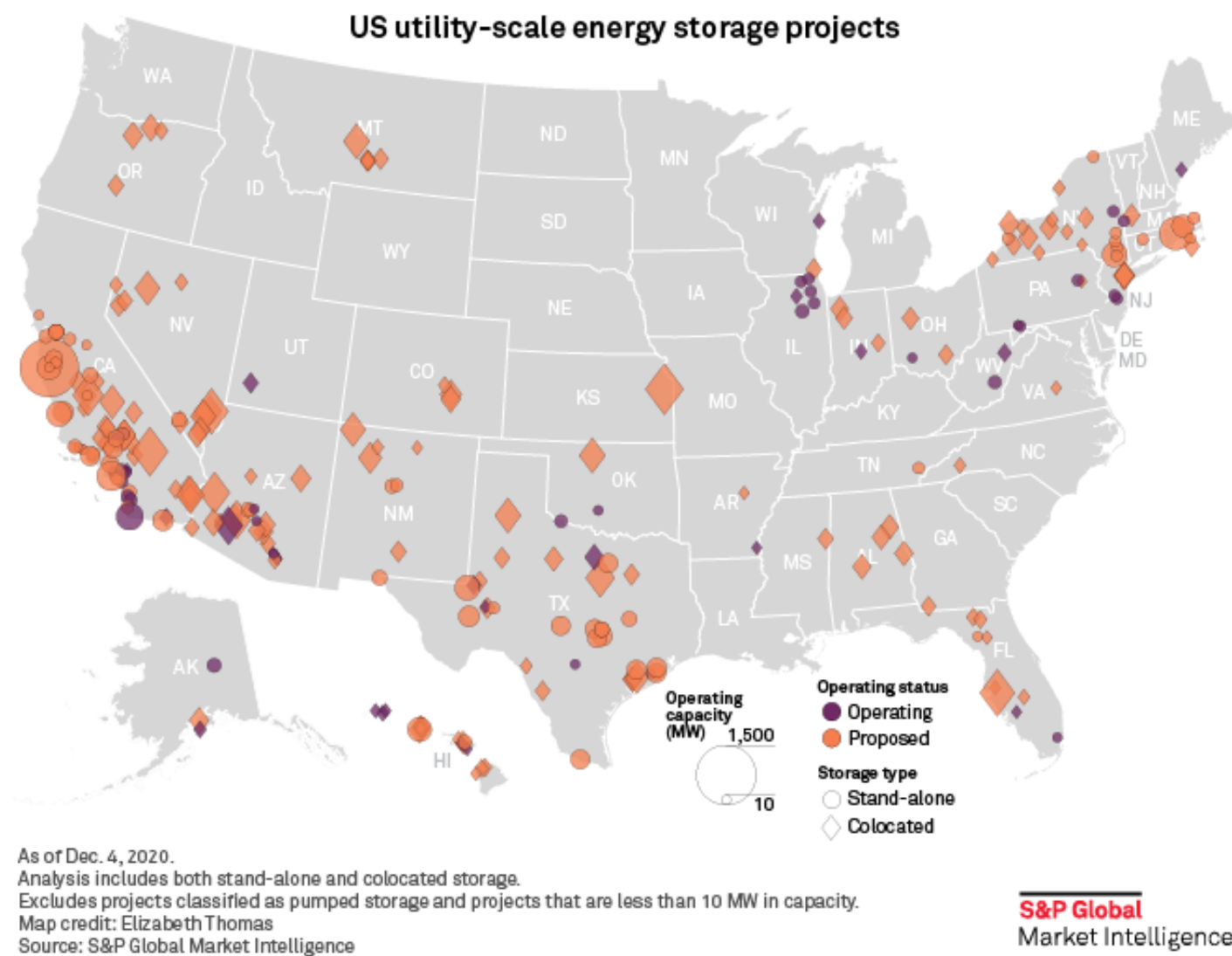


Figure 6.12-2: U.S. Utility-Scale Energy Storage Projects (December 2020)⁶⁶

66

Hering, G. (2020, December 21). COVID-19 slows breakout year for US battery storage in 2020. Retrieved April 22, 2021, from <https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/covid-19-slows-breakout-year-for-us-battery-storage-in-2020-61754679>



Pumped Energy Storage Overview

Pumped storage utilizes the laws of gravity to create energy. During times of low demand, cheap prices, and surplus generation, water is pumped into a storage reservoir at an elevation higher than where the generating facility resides. When demand is higher and resources are needed, the water flows downhill to the hydroelectric generators producing electricity.

There are two types of pumped storage, open-loop and closed-loop. Open-loop systems are connected to a natural flowing water supply, whereas a closed-loop system uses a lower reservoir that is not constantly filled with water. These two systems are shown in Figure 6.12-3.

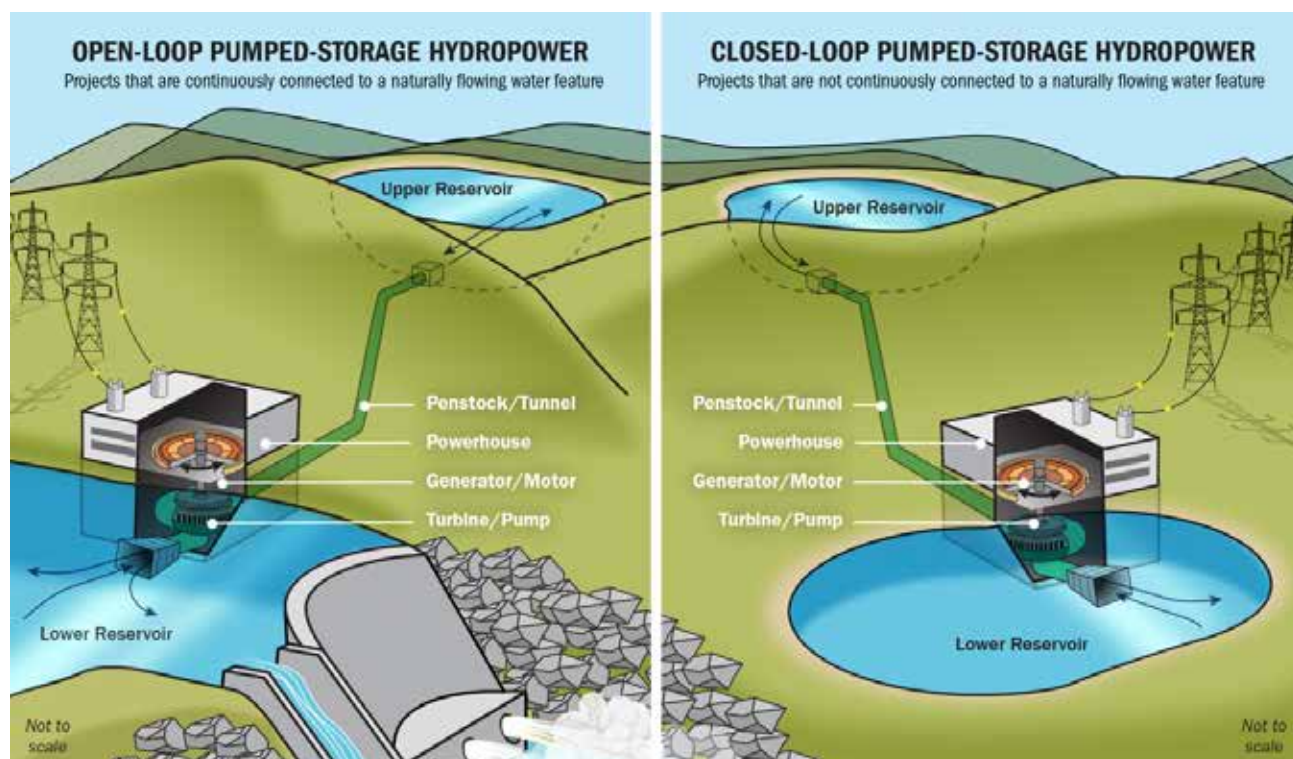


Figure 6.12-3: Open/Closed Loop Pumped Storage HydroPower Diagram⁶⁷

67 Mayes, F. (2019, October 31). Most pumped storage electricity generators in the U.S. were built in the 1970s. Retrieved April 22, 2021, from <https://www.eia.gov/todayinenergy/detail.php?id=41833#:~:text=Pumped%20storage%20involves%20pumping%20water,hydroelectric%20generators%20at%20a%20dam.>



Most pumped storage projects in the U.S. were built between 1960 and 1990, with nearly 50% being built in the 1970s. There is currently 18.9 GW of pumped storage in the U.S. Figure 6.12-4 shows the existing pumped storage facilities in the U.S.

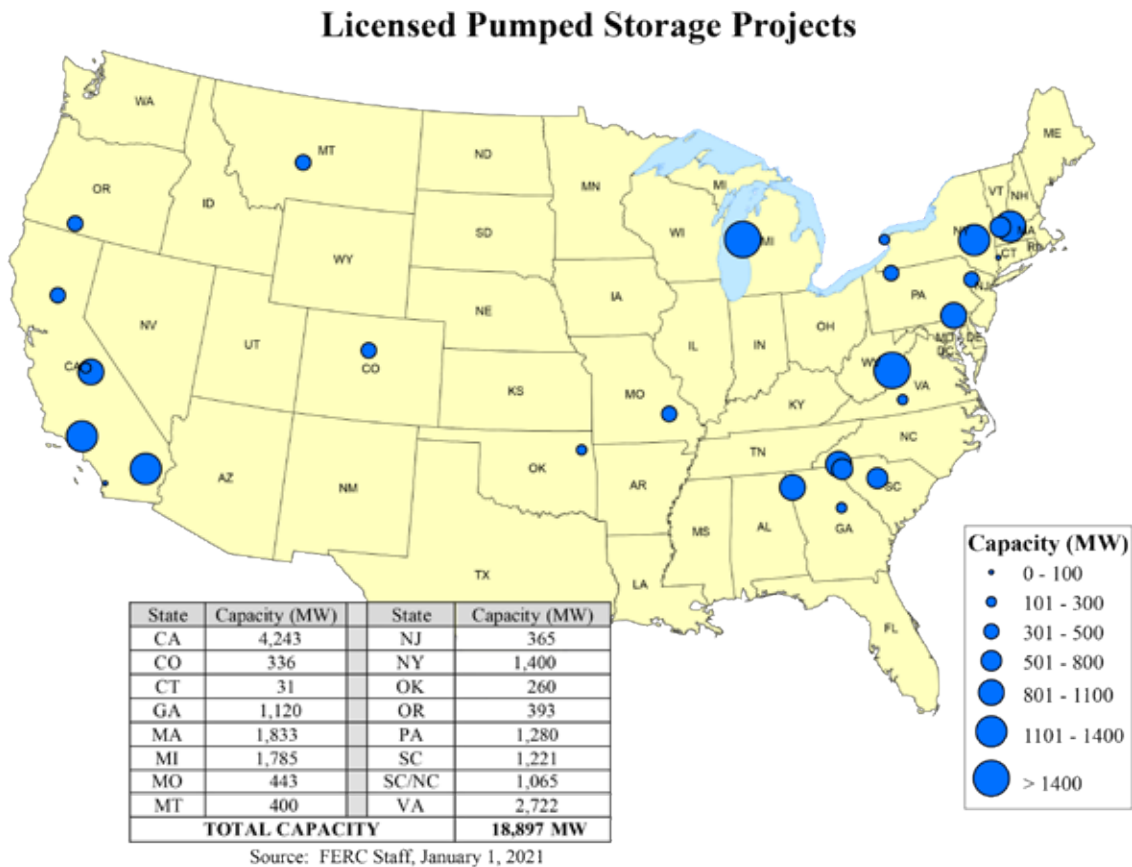


Figure 6.12-4: Licensed Pumped Storage Projects (2021)⁶⁸

The Federal Energy Regulatory Commission (FERC) has recently seen an increase in the number of preliminary permit and license applications for pumped storage projects which aligns with the decarbonizing efforts that require large energy storage opportunities.

Pumped storage facilities cost more than traditional dam projects as they require a storage reservoir, pump equipment, and incremental piping. Pump storage projects require roughly 15% to 30% more energy to pump water into the reservoir than they generate when the water is released downhill.

68 FERC. (2021, January 21). Pumped storage projects. Retrieved April 22, 2021, from <https://www.ferc.gov/industries-data/hydropower/licensing/pumped-storage-projects>



Compressed Air Energy Storage Overview

Compressed Air Energy Storage (CAES) uses surplus energy during low demand periods to compress air via a compressor and stores it in underground caverns or in storage tanks. When additional energy is needed, the compressed air is fed through pressure turbines which spin a generator to produce electricity. To date, there are two operational CAES plants in the world—a 290 MW facility in Huntorf, Germany, and the 110 MW plant in McIntosh, Alabama. The Huntorf plant was commissioned in 1978 and the McIntosh plant 1991. The basic concept is shown in Figure 6.12-5.

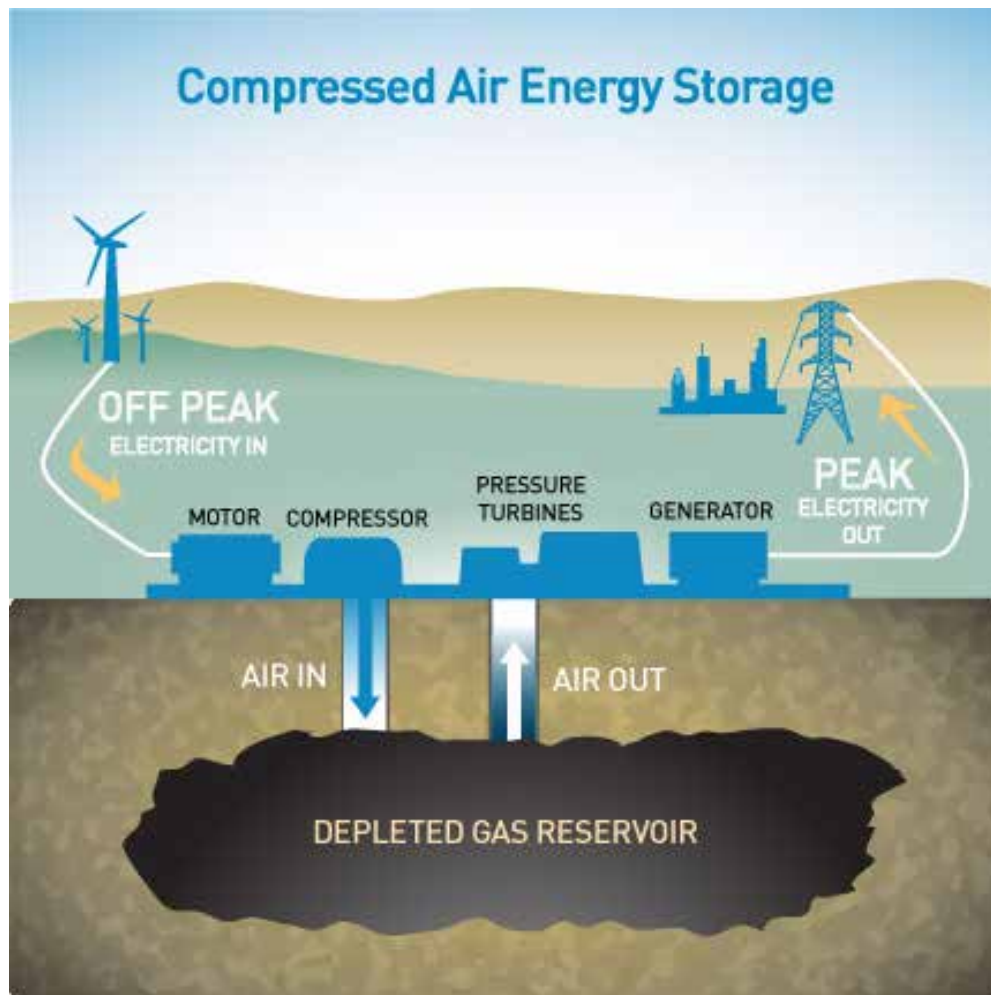


Figure 6.12-5: Compressed Air Energy Storage Diagram⁶⁹

69 PG&E. (n.d.). Discover renewable energy technology with compressed air energy storage. Retrieved April 22, 2021, from https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/compressed-air-energy-storage/compressed-air-energy-storage.page



Flywheel Energy Storage Overview

Flywheel energy storage systems utilize kinetic energy to produce electricity. Kinetic energy is defined as energy that a body possesses by virtue of being in motion. In a flywheel energy storage system, a large mass contained within a vacuum-sealed container is spun at tremendous speeds with the use of a motor. The chamber acts as protection from failure and is vacuum sealed to maximize efficiency. The mass sits above magnetic bearings to reduce friction and mechanical wear. When the stored energy is recovered by the spinning of the mass, the motor acts as a generator and produces electricity. Figure 6.12-6 shows the basic concept of flywheel energy storage.

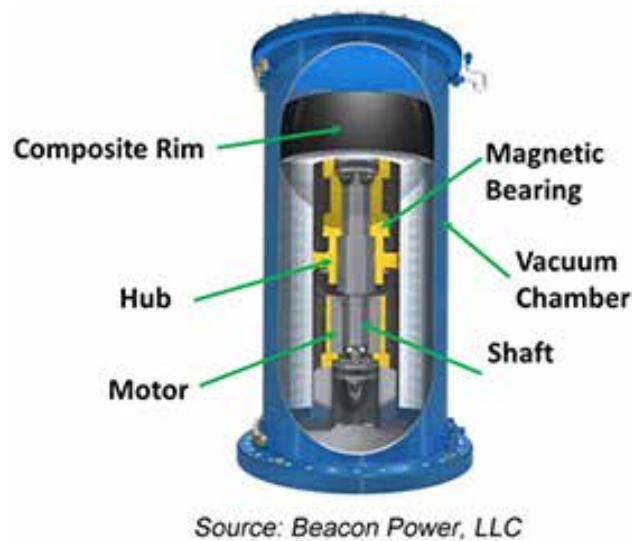


Figure 6.12-6: Flywheel Energy Storage Systems Diagram⁷⁰

70 ESA. (2021, April 07). Mechanical electricity storage technology. Retrieved April 22, 2021, from <https://energystorage.org/why-energy-storage/technologies/mechanical-energy-storage/>



Concrete Block Energy Storage Overview

Concrete block storage works on the same principle as pumped storage, except instead of using water as the kinetic energy source, concrete blocks are used. Concrete blocks weighing tens of tons are hoisted up a tower via a motor driven multi-arm crane where they are stored. The lifting process is done during low demand, low pricing environments. When energy is needed, the concrete blocks are allowed to succumb to gravity and the stored kinetic energy is converted to electricity using the same motors that were used to lift the blocks previously in generator mode. The technology offers the potential for long lasting energy storage. Figure 6.12-7 shows a rendering of concrete block storage from a Swiss company called Energy Vault.



Figure 6.12-7: Concrete Block Energy Storage Diagram⁷¹

⁷¹ Grossman, D. (2019, October 14). Are concrete blocks the next batteries? Retrieved April 22, 2021, from <https://www.popularmechanics.com/technology/infrastructure/a29463165/concrete-block-energy-storage/>



Risk Considerations

Risks associated with storage technologies include:

Siting – Pumped storage requires a location where elevation levels are suitable to harness the kinetic energy stored in the upper water reservoir. Compressed air storage on a large scale requires access to underground caverns.

Availability – All storage resources do not produce energy. Any storage project must have access to energy resources to power the motors specific to the storage technology, such as pumps.

Pricing – Storage resources must maintain competitiveness when being dispatched against other technologies.

Effectiveness – Storage technologies need to be proven. Pumped storage has a proven track record but is a pricey option. Compressed air storage's most recent large-scale project was commissioned in 1991, making the technology somewhat dated.

Future of Other Storage in Kentucky

Storage technologies are feasible for Kentucky. They will need to be monitored for continued development and pricing, as well as evaluated against alternate solutions. KYMEA did not receive any proposals in its RFP2020 associated with other storage technologies.



6.13 Distributed Generation

Overview

Distributed generation refers to a variety of technologies that generate electricity in close proximity to where it will be used, such as rooftop solar panels. The placement and relatively small size of most of the distributed generation mean that it is an issue addressed by the policies and net-metering rate tariffs of the distribution utility, which serves the retail customer(s) who own the generation. The customer reduces its load served by the utility by the amount of generation produced each month. KYMEA lends support where necessary to its members to achieve their individual utility objectives. Larger distributed generation projects which do not qualify under the local utility's net metering policy could be handled by KYMEA under the Public Utility Regulatory Policies Act (PURPA), where KYMEA would pay the customer KYMEA's avoided cost for the energy and capacity, but the retail customer would not deduct the generation quantity from its local power bill. The two concepts are mutually exclusive and not combined.

The United States has more than 12 million distributed generation units, about one-sixth of the capacity of the nation's power plants. Contributing to this growth, is the dramatic decrease in the cost of distributed generation technology, as well as increased governmental and utility incentives for installations. These units can be used in both the commercial and residential sectors and may include common distributed generation systems such as solar panels, wind turbines, natural-gas-fired fuel cells, biomass combustion, hydropower, emergency backup generators, or reciprocating combustion engines.



Figure 6.13-1: Rooftop Solar Panel⁷²

72 Castlereagh Associates. (2019, June 25). Rooftop Solar Panel [Digital image]. Retrieved April 22, 2021, from <https://castlereagh.net/middle-east-utilities-vs-distributed-generation-a-losing-battle/>



Technology

Distributed generation may serve a single structure, such as a home or business, or it may be part of a microgrid at an industrial facility or a college campus. Microgrids are smaller grids that are also tied into the larger electric distribution system, as shown in Figure 6.13-2. They generally stay connected to the overall grid, but can disconnect and operate autonomously when necessary. When connected to the electric utility's lower voltage distribution lines, distributed generation can help support delivery of clean, reliable power to additional customers and reduce electricity losses along transmission and distribution lines.

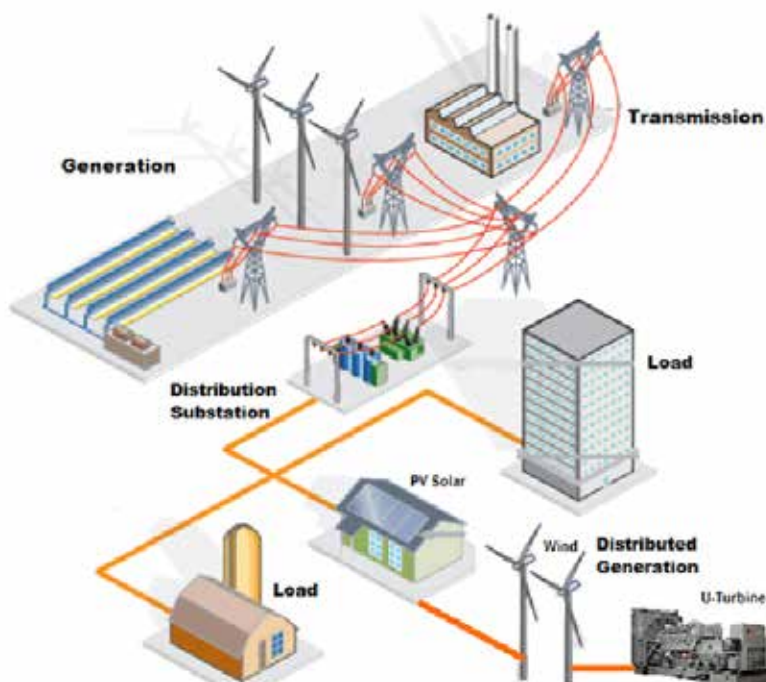


Figure 6.13-2: Distributed Generation Diagram⁷³

The use of distributed generation has many benefits:

- Increased electric system reliability
- An emergency supply of power
- Reduction of peak power and reserve requirements
- Offsets to investments in generation, transmission, or distribution facilities that would otherwise be recovered through rates
- Provision of ancillary services, including reactive power
- Improvements in power quality
- Reductions in land-use effects and rights-of-way acquisition costs

Furthermore, distributed generation may benefit the environment if its use reduces the amount of electricity that must be generated at carbon fuel based power plants.

73 Aman, Engr & Ahmad, Sanaullah & ul, Azzam & Noor, Babar. (2017). Analyzing the Diverse Impacts of Conventional Distributed Energy Resources on Distribution System. International Journal of Advanced Computer Science and Applications. 8. 10.14569/IJACSA.2017.081051.



Risks Considerations

Unfortunately, distributed generation can also lead to negative environmental impacts. These systems take up space; and, because they are located closer to the end-user, some distributed generation systems might be unpleasant to the eye or cause land-use concerns. Distributed generation technologies that involve combustion—particularly burning fossil fuels—can produce many of the same types of impacts as larger fossil-fuel-fired power plants, such as air pollution. These impacts may be smaller in scale than the impacts from a large power plant but may also be closer to populated areas. Some distributed generation technologies, such as waste incineration, biomass combustion, and combined heat and power, may require water for steam generation or cooling. Distributed generation systems that use combustion may be less efficient than centralized power plants due to efficiencies of scale. Distributed energy technologies may also cause some negative environmental issues at the end of their useful life when they are replaced or removed.

Distributed generation may also pose the following operational and economic challenges to electric utilities and their customers.

- **Operational issues** - may exist with regard to distributed generation. An over-abundance of distributed generation could cause excess demand at a substation, resulting in a power flow from a substation to the transmission grid and creating high voltage swings and stress on electric equipment. It may also threaten line worker safety through such events as when it continuously energizes a feeder even though the utility is no longer supplying power due to an outage. Furthermore, distributed generation is problematic to monitor and may negatively impact load forecasts. Utility customers with distributed generation introduce additional operational complexities for transmission, distribution, and generation systems more than other customers. Utilities will have to make capital investments to compensate for strains on the system, and these costs are potentially socialized to all utility rate payers.
- **Economic issues** - also arise from distributed generation. Many electric utilities compensate distributed generation customers through net metering. Under such a program, the utility will credit customers with distributed generation for their kilowatt-hour sales to the grid and then charge them for periods when electricity consumption from the grid exceeds their generation. Under many net-metering programs, the customer is both charged and credited at the utility's full retail rate of electricity, thus potentially over-compensating distributed generators with a value of generation that is higher than the utility's avoided cost. Alternatively, some utilities have designed compensation schemes to appropriately value the full costs associated with distributed generation, including increased customer charges for fixed costs, residential demand charges according to peak kilowatt usage or time-based pricing. Other utilities have implemented net billing or buy-all, sell-all arrangements where excess generation is compensated at an avoided cost rate. If utilities do not implement compensation plans that correctly account for fixed charges, it may inadvertently create an economic burden for both the utility and rate payers.

Distributed generation may have a role in helping meet energy requirements and achieving environmental goals as long as customers pay their fair share of the costs necessary to keep the grid operating safely and reliably. Rate design and regulatory requirements should take into account a utility's technical limitations and geographic considerations.⁷⁴

74 EPA. (2021, February 19). Distributed generation of electricity and its environmental impacts. Retrieved April 22, 2021, from <https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts>



Future of Distributed Generation in Kentucky

As of 2018, Kentucky has 34 MW of distributed renewable resources. Of this 34 MW, 30% is interconnected through a net-metering arrangement and 70% is interconnected by a non net-metering arrangement. Most of the distributed generation (80%) is solar in nature, a small portion (19%) of the resources are biomass and landfill gas, while the remaining resources are small wind and hydroelectric.

Kentucky has 1500 distributed renewable interconnections, 75% of which are net-metering arrangement while 25% are non net-metering arrangements. Figure 6.13-3 and 6.13-4 provide information of the total distributed renewables (kW) net-metered and non net-metered installed capacity per county in 2018.

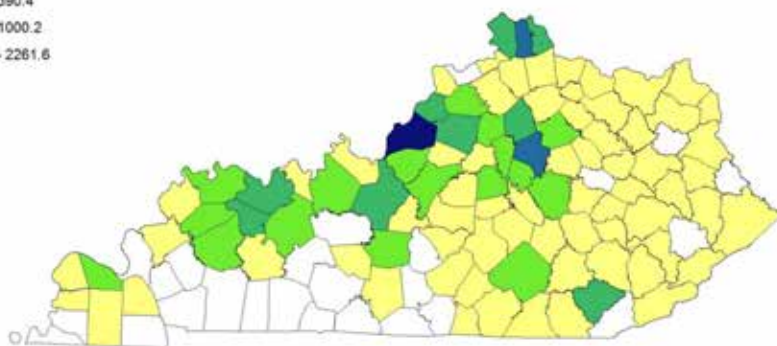
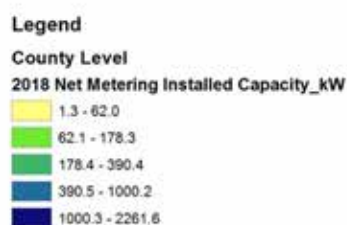


Figure 6.13-3: 2018 Net-Metering Installed Capacity (kW) by County⁷⁵

⁷⁵ Kentucky Energy Profile (7th ed., Rep.). (2019). Kentucky Energy and Environment Cabinet Office of Energy Policy. doi:<https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202019.pdf>

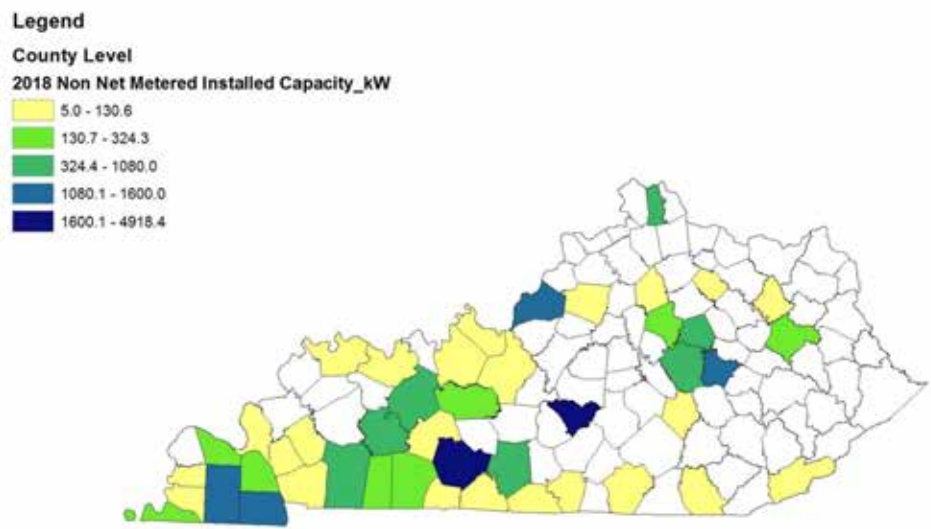


Figure 6.13-4: 2018 Non Net-Metered Installed Capacity (kW) by County⁷⁶

76 Kentucky Energy Profile (7th ed., Rep.). (2019). Kentucky Energy and Environment Cabinet Office of Energy Policy. doi:<https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202019.pdf>



6.14 Demand Side Management

Overview

The idea of demand-side management came about in the 1970s as the planning and implementation of activities designed to influence customers' use of electricity began to take on greater importance than ever before. Utilities sought to change their load shapes by altering the time patterns and magnitudes of load produced by customers. If successful, utilities could lower, defer, or eliminate costs associated with constructing new power plants and transmission lines, save rate payers money, and lower pollution from fossil fuel generation.

Energy efficiency programs are the largest demand-side management tool employed by utilities. Customer incentives to increase efficiency and decrease electricity demand are focused on residential and commercial customers. The majority of spending on energy efficiency programs is spent as free or low-cost energy audits of homes and businesses, free or discounted energy efficient light bulbs, and rebates to customers for purchasing energy efficient or ENERGY STAR-certified appliances such as refrigerators, freezers, hot water heaters, and air-conditioning equipment.

Utility demand response programs tend to be smaller than energy efficiency programs, but they are very effective in decreasing peak demand in order to reduce the possibility of blackouts and the need to construct new generation to meet extra demand. These programs typically offer customers a rebate or lower energy rates for reducing electricity use during periods of high demand or allowing the utility to cycle their usage when needed.

The debate surrounding demand-side management programs tends to ask whether the cost of such programs justifies the benefits derived.

Program Costs

In 2017, efficiency programs cost utilities approximately \$6B, while demand response programs added over \$1.5B, shown in Figure 6.14-1.

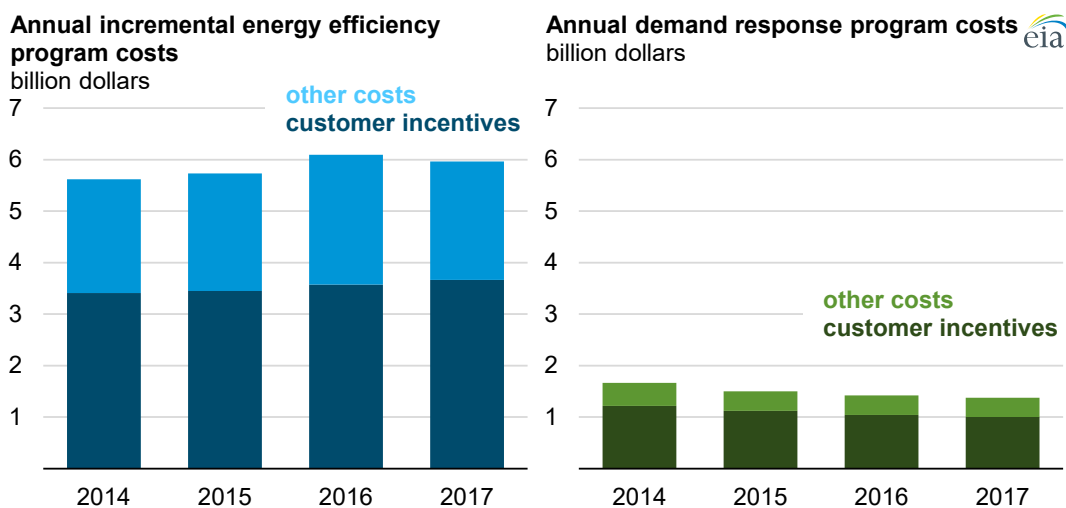


Figure 6.14-1: Efficiency and Demand Response Program Costs⁷⁷

⁷⁷ Aniti, L. (2019, March 29). Demand-side management programs save energy and reduce peak demand. Retrieved April 22, 2021, from <https://www.eia.gov/todayinenergy/detail.php?id=38872>



Program Savings

This cash outlay saved utilities over 30 million MWh and almost 20 thousand MW in peak demand, shown in Figure 6.14-2.

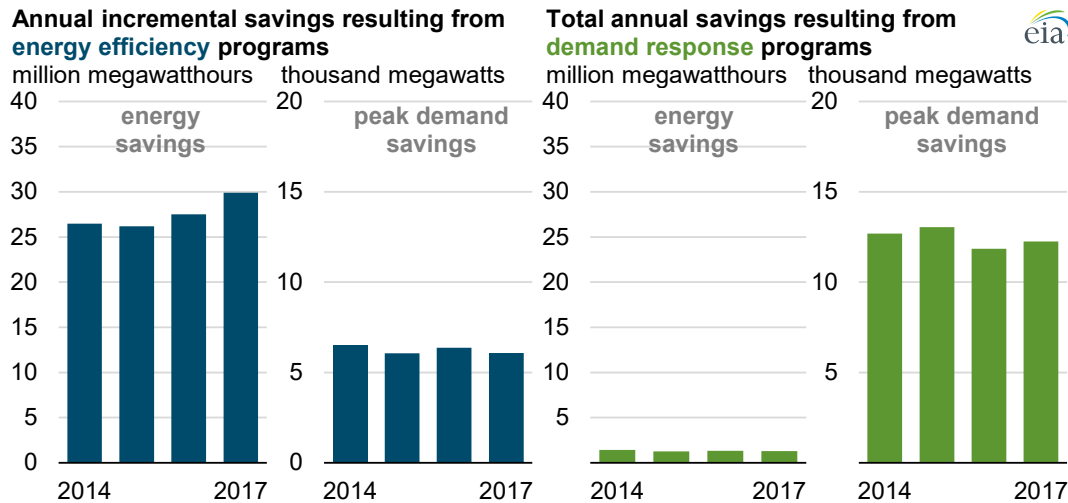


Figure 6.14-2: Efficiency and Demand Response Savings⁷⁸

New energy efficiency programs saved 1 kWh for every 20 cents spent in 2017. Some would contend that this money is well spent if it increases the reliability of regional transmission organizations and reduces blackouts. Figure 6.14-3 shows the 2017 peak demand savings from demand response for BAs across the U.S.

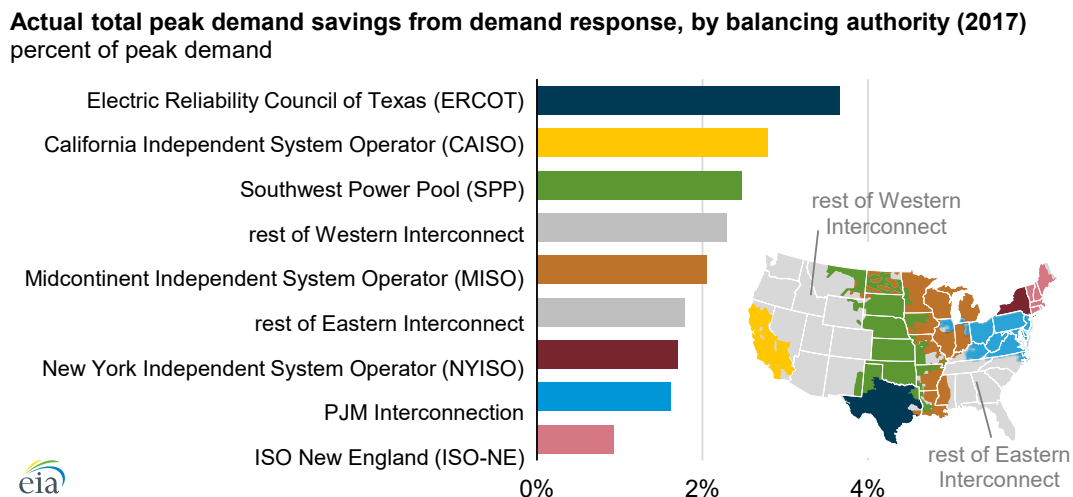


Figure 6.14-3: Actual Total Peak Demand Savings from Demand Response in 2017⁷⁹

78 Aniti, L. (2019, March 29). Demand-side management programs save energy and reduce peak demand. Retrieved April 22, 2021, from <https://www.eia.gov/todayinenergy/detail.php?id=38872>

79 Aniti, L. (2019, March 29). Demand-side management programs save energy and reduce peak demand. Retrieved April 22, 2021, from <https://www.eia.gov/todayinenergy/detail.php?id=38872>



Future of Demand-Side Management in Kentucky

KYMEA is not directly responsible for managing relationships with retail customers served by its members—relationships with retail customers are managed by the members. KYMEA is in a position to support members in evaluating and developing demand-side programs.



6.15 Resource Cost and Performance

Tables 6.15-1 through 6.15-5 represent cost and environmental data for various energy technologies. When available, KYMEA will use the more accurate cost and performance data obtained through the RFP process.

Table 6.15-1: Cost and Performance Summary Table (Sargent & Lundy)⁸⁰

Case No.	Technology	Description	Net Nominal Capacity (kW)	Net Nominal Heat Rate (Btu/kWh)	Capital Cost (\$/kW)	Fixed O&M Cost (\$/kW-yr)	Variable O&M Cost (\$/MWh)	NO _x (lb/MMBtu)	SO ₂ (lb/MMBtu)	CO ₂ (lb/MMBtu)
1	650 MW Net, Ultra-Supercritical Coal w/o Carbon Capture - Greenfield	1 x 735 MW Gross	650	8638	3676	40.58	4.5	0.06	0.09	206
2	650 MW Net, Ultra-Supercritical Coal 30% Carbon Capture	1 x 769 MW Gross	650	9751	4558	54.3	7.08	0.06	0.09	144
3	650 MW Net, Ultra-Supercritical Coal 90% Carbon Capture	1 x 831 MW Gross	650	12507	5876	59.54	10.98	0.06	0.09	20.6
4	Internal Combustion Engines	4 x 5.6 MW	21	8295	1810	35.16	5.69	0.02	0	117
5	Combustion Turbines- Simple Cycle	2 x LM6000	105	9124	1175	16.3	4.7	0.09	0.00	117
6	Combustion Turbines- Simple Cycle	1 x GE 7FA	237	9905	713	7	4.5	0.03	0.00	117
7	Combined-Cycle 2x2x1	GE 7HA.02	1083	6370	958	12.2	1.87	0.0075	0.00	117
8	Combined-Cycle 1x1x1, Single Shaft	H Class	418	6431	1084	14.1	2.55	0.0075	0.00	117
9	Combined-Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture	H Class	377	7124	2481	27.6	5.84	0.0075	0.00	11.7
10	Fuel Cell	34 x 300 kW Gross	10	6469	6700	30.78	0.59	0.0002	0	117
11	Advanced Nuclear (Brownfield)	2 x AP1000	2156	10608	6041	121.64	2.37	0	0	0
12	Small Modular Reactor Nuclear Power Plant	12 x 50-MW Small Modular Reactor	600	10046	6191	95	3.00	0	0	0
13	50-MW Biomass Plant	Bubbling Fluidized Bed	50	13300	4097	125.72	4.83	0.08	<0.03	206
14	10% Biomass Co-Fire Retrofit	300-MW PC Boiler	30	+ 1.5%	705	25.57	1.90	0%-20%	-8%	-8%
15	Geothermal	Binary Cycle	50	N/A	2521	128.544	1.16	0	0	0
16	Internal Combustion Engines- Landfill Gas	4 x 9.1 MW	35.6	8513	1563	20.1	6.2	0.02	0	117
17	Hydroelectric Power Plant	New Stream Reach Development	100	N/A	5316	29.86	0	0	0	0
18	Battery Energy Storage System	50 MW 200 MWh	50	N/A	1389 (347 \$/kWh)	24.8	0	0	0	0
19	Battery Energy Storage System	50 MW 100 MWh	50	N/A	845 (423 \$/kWh)	12.9	0	0	0	0
20	Onshore Wind- Large Plant Footprint: Great Plains Region	200 MW 2.82 MW WTG	200	N/A	1265	26.34	0	0	0	0
21	Onshore Wind- Small Plant Footprint: Coastal Region	50 MW 2.78 MW WTG	50	N/A	1677	35.14	0	0	0	0
22	Fixed-Bottom Offshore Wind: Monopile Foundations	400 MW 10 MW WTG	400	N/A	4375	110	0	0	0	0
23	Concentrating Solar Power Tower	w/ Molten Salt Thermal Storage	115	N/A	7221	85.4	0	0	0	0
24	Solar PV w/ Single Axis Tracking	150 MWAC	150	N/A	1313	15.25	0	0	0	0
25	Solar PV w/ Single Axis Tracking + Battery Storage	150 MWAC Solar 50 MW 200 MWh Storage	150	N/A	1755	31.27	0	0	0	0

80 Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (Rep.). (2020, February). Retrieved April 22, 2021, from EIA website: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

Table 6.15-2: Cost and Performance Lithium-Ion Summary Table⁸¹

ESS Installed Cost		Lithium-ion LFP														
		1 MW					10 MW					100 MW				
		2 hr	4 hr	6 hr	8 hr	10 hr	2 hr	4 hr	6 hr	8 hr	10 hr	2 hr	4 hr	6 hr	8 hr	10 hr
Storage Block (\$/kWh)		[89-129] 111	[87-128] 109	[87-127] 108	[86-126] 108	[86-125] 107	[85-123] 106	[83-122] 104	[83-121] 103	[82-120] 103	[82-119] 102	[81-118] 101	[79-116] 99	[79-115] 98	[78-114] 98	[78-114] 97
Storage Balance of System (\$/kWh)		[27-37] 32	[25-35] 30	[25-34] 29	[24-33] 28	[24-33] 28	[26-36] 30	[24-33] 28	[24-32] 27	[23-32] 27	[23-31] 27	[25-34] 29	[23-32] 27	[22-31] 26	[22-30] 26	[22-30] 25
Power Equipment (\$/kW)		[59-77] 73	[59-77] 73	[59-77] 73	[59-77] 73	[59-77] 73	[51-66] 63	[51-66] 63	[51-66] 63	[51-66] 63	[51-66] 63	[44-57] 54	[44-57] 54	[44-57] 54	[44-57] 54	[44-57] 54
Controls & Communication (\$/kW)		[24-33] 28	[24-33] 28	[24-33] 28	[24-33] 28	[24-33] 28	[5-6] 5	[5-6] 5	[5-6] 5	[5-6] 5	[5-6] 5	[1-1] 1	[1-1] 1	[1-1] 1	[1-1] 1	[1-1] 1
System Integration (\$/kWh)		[42-51] 46	[37-46] 36	[35-44] 33	[35-42] 32	[34-42] 32	[38-47] 38	[35-42] 33	[33-41] 31	[32-40] 30	[32-39] 30	[36-44] 35	[33-40] 31	[31-39] 30	[31-38] 29	[30-37] 28
Engineering, Procurement, & Construction (\$/kWh)		[52-64] 57	[45-56] 50	[43-53] 48	[42-51] 46	[41-50] 45	[46-57] 51	[42-51] 46	[40-49] 44	[39-48] 43	[37-47] 43	[43-53] 48	[39-48] 43	[38-46] 42	[37-45] 41	[36-45] 40
Project Development (\$/kWh)		[62-76] 69	[54-67] 60	[52-63] 57	[50-62] 56	[49-61] 55	[55-68] 61	[50-61] 55	[48-59] 53	[47-58] 52	[46-57] 51	[51-63] 57	[47-58] 52	[45-56] 50	[44-54] 49	[44-54] 48
Grid Integration (\$/kWh)		[23-28] 25	[23-28] 25	[23-28] 25	[23-28] 25	[23-28] 25	[18-23] 20	[18-23] 20	[18-23] 20	[18-23] 20	[18-23] 20	[15-18] 16	[15-18] 16	[15-18] 16	[15-18] 16	[15-18] 16
Total ESS Installed Cost*	\$/kW	[650-854] \$757	[1105-1460] \$1,266	[1555-2059] \$1,780	[2002-2654] \$2,290	[2447-3245] \$2,797	[575-757] \$661	[1008-1334] \$1,156	[1437-1905] \$1,645	[1863-2471] \$2,131	[2287-3035] \$2,614	[531-699] \$610	[944-1249] \$1,081	[1353-1793] \$1,547	[1758-2333] \$2,010	[2162-2870] \$2,471
	\$/kWh	[325-427] \$378	[276-365] \$317	[259-343] \$297	[250-332] \$286	[245-325] \$280	[287-378] \$330	[252-333] \$289	[240-317] \$274	[233-309] \$266	[229-303] \$261	[265-350] \$305	[236-312] \$270	[225-299] \$258	[220-292] \$251	[216-287] \$247
Operating Costs		1 MW					10 MW					100 MW				
		2 hr	4 hr	6 hr	8 hr	10 hr	2 hr	4 hr	6 hr	8 hr	10 hr	2 hr	4 hr	6 hr	8 hr	10 hr
Fixed O&M (\$/kW-yr)		[1.86-2.29] 2.07	[3.26-4.00] 3.61	[4.63-5.70] 5.13	[6.00-7.38] 6.65	[7.36-9.05] 8.16	[1.65-2.03] 1.83	[2.98-3.67] 3.30	[4.29-5.28] 4.76	[5.60-6.88] 6.20	[6.89-8.48] 7.64	[1.54-1.89] 1.70	[2.80-3.44] 3.10	[4.05-4.98] 4.49	[5.29-6.51] 5.86	[6.53-8.03] 7.23
Variable O&M (\$/MWh)		0.5125					0.5125					0.5125				
System RTE Losses (\$/kWh)		0.004					0.004					0.004				
Performance Metrics		1 MW					10 MW					100 MW				
		2 hr	4 hr	6 hr	8 hr	10 hr	2 hr	4 hr	6 hr	8 hr	10 hr	2 hr	4 hr	6 hr	8 hr	10 hr
Round Trip Efficiency (%)		88%					88%					88%				
Response Time (sec)		1-4					1-4					1-4				
Cycle Life (#)		2,100					2,100					2,100				
Calendar Life (yrs)		10					10					10				
Duration Corresponding to Cycle Life** (yrs)		6.06					6.06					6.06				

*Does not include warranty, insurance, or decommissioning costs

**Assumes 80% depth of discharge, one cycle/day, and 5% downtime

81 2020 Grid Energy Storage Technology Cost and Performance Assessment (Rep. No. Publication No. DOE/PA-0204). (2020, December). Retrieved April 22, 2021, from 2020 Grid Energy Storage Technology Cost and Performance Assessment, <https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf>

Table 6.15-3: Cost and Performance Hydrogen Summary Table⁸²

ESS Installed Cost		Hydrogen (Bi-directional)	
		100 MW	
		10 hr	
		2020	2030
Electrolyzer Capital Cost (\$/kW)		[1353-1653] 1,503	[393-481] 437
Rectifier (\$/kW)		[117-143] 130	[84-103] 94
Compressor (\$/kW)		[35-43] 39.30	[35-43] 39.30
Cavern Storage (\$/kWh)		[2-10] 3.66	[2-8] 3.09
Stationary Fuel Cell Capital Cost (\$/kW)		[1188-1452] 1,320	[854-1044] 949
Inverter (\$/kW)		[60-74] 67	[41-50] 45
Controls & Communication (\$/kW)		[1.35-1.65] 1.50	[0.95-1.16] 1.06
Grid Integration (\$/kW)		[18-22] 19.89	[15-18] 16.30
Total ESS Installed Cost*	(\$/kW)	[2793-3488] \$3,117	[1440-1824] \$1,612
	(\$/kWh)	[279-349] \$312	[144-182] \$161
Operating Costs		100 MW	
		10 hr	
		2020	2030
Fixed O&M (\$/kW-yr)		[26.02-31.80] 28.51	
Variable O&M (\$/MWh)		0.5125	
System RTE Losses (\$/kWh)		0.056	
Performance Metrics		100 MW	
		10 hr	
		2020	2030
Round Trip Efficiency (%)		35%	
Response Time (sec)		<1	
Cycle Life (#)		10,403	
Calendar Life (yrs)		30	
Duration Corresponding to Cycle Life** (yrs)		30	
*Does not include warranty, insurance, or decommissioning costs			
**Assumes 80% depth of discharge, one cycle/day, and 5% downtime			

82 2020 Grid Energy Storage Technology Cost and Performance Assessment (Rep. No. Publication No. DOE/PA-0204). (2020, December). Retrieved April 22, 2021, from 2020 Grid Energy Storage Technology Cost and Performance Assessment, <https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf>

Table 6.15-4: Cost and Performance Pumped Storage Summary Table⁸³

ESS Cost		Pumped Storage Hydro								
		100 MW				1,000 MW				
		4 hr		10 hr		4 hr		10 hr		
		2020	2030	2020	2030	2020	2030	2020	2030	
Reservoir Construction & Infrastructure (\$/kWh)		[73-89] 81		[68-83] 76		[61-75] 68		[57-70] 64		
Powerhouse Construction & Infrastructure (\$/kW)		[321-817] 742		[321-817] 742		[270-686] 623		[270-686] 623		
Electro-mechanical (\$/kW)		[420-513] 467		[420-513] 467		[353-431] 392		[353-431] 392		
Total ESS Installed Cost*	(\$/kW)	[1034-1688] \$1,534		[1424-2164] \$1,967		[868-1417] \$1,288		[1195-1817] \$1,651		
	(\$/kWh)	[259-422] \$384		[142-216] \$197		[217-354] \$322		[120-182] \$165		
Total ESS Installed Cost + Contingency Fee*	(\$/kW)	[1301-2250] \$2,046		[1792-2885] \$2,623		[1093-1889] \$1,717		[1504-2422] \$2,202		
	(\$/kWh)	[325-563] \$511		[179-289] \$262		[273-472] \$429		[150-242] \$220		
Operating Costs		100 MW				1,000 MW				
		4 hr		10 hr		4 hr		10 hr		
		2020	2030	2020	2030	2020	2030	2020	2030	
Fixed O&M (\$/kW-yr)		[27.36-33.44] 30.40				[16.02-19.58] 17.80				
Variable O&M (\$/MWh)		0.5125				0.5125				
System RTE Losses (\$/kWh)		0.0075				0.0075				
Performance Metrics		100 MW				1,000 MW				
		4 hr		10 hr		4 hr		10 hr		
		2020	2030	2020	2030	2020	2030	2020	2030	
Round Trip Efficiency (%)		80%				80%				
Response Time(s) (sec)	Scenario					Fixed		Variable		Ternary
	Spinning-in-air to full load generation					5-70		60		20-40
	Shutdown to full generation					75-120		90		65-90
	Spinning-in-air to full load					50-80		70		25-30
	Shutdown to full load					160-360		230		80-85
	Full load to full generation					90-220		280		25-60
Full generation to full load					240-500		470		25-45	
Cycle Life (#)		13,870				13,870				
Calendar Life (yrs)		40				40				
Duration Corresponding to Cycle Life** (yrs)		40				40				
*Does not include warranty, insurance, or decommissioning costs										
**Assumes 80% depth of discharge, one cycle/day, and 5% downtime										

83 2020 Grid Energy Storage Technology Cost and Performance Assessment (Rep. No. Publication No. DOE/PA-0204). (2020, December). Retrieved April 22, 2021, from 2020 Grid Energy Storage Technology Cost and Performance Assessment, <https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf>

Table 6.15-5: Cost and Performance Compressed Air Energy Storage Summary Table⁸⁴

ESS Cost		Compressed Air Energy Storage											
		100 MW				1,000 MW				10,000 MW			
		4 hr		10 hr		4 hr		10 hr		4 hr		10 hr	
		2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
Capital Cost Related to Turbine, Compressor, BOP, and EPC Management (\$/kW)		[1038-1268] 1153		[1038-1268] 1153		[955-1167] 1061		[955-1167] 1061		[878-1073] 976		[878-1073] 976	
Cavern Capital Cost (\$/kWh)		[2-10] 3.66	[2-10] 3.09	[2-10] 3.66	[2-10] 3.09	[2-9] 3.37	[2-9] 2.85	[2-9] 3.37	[2-9] 2.85	[1-7] 3.10	[1-7] 2.62	[1-7] 3.10	[1-7] 2.62
Total ESS Installed Cost*	(\$/kW)	[1046-1308] \$1,168	[1044-1302] \$1,165	[1058-1368] \$1,190	[1055-1353] \$1,184	[962-1204] \$1,074	[961-1198] \$1,072	[973-1259] \$1,094	[970-1245] \$1,089	[885-1107] \$988	[884-1102] \$986	[895-1158] \$1,007	[893-1145] \$1,002
	(\$/kWh)	[261-327] \$292	[261-326] \$291	[106-137] \$119	[105-135] \$118	[241-301] \$269	[240-299] \$268	[97-126] \$109	[97-124] \$109	[221-277] \$247	[221-276] \$247	[90-116] \$101	[89-115] \$100
Operating Costs		100 MW				1,000 MW				10,000 MW			
		4 hr		10 hr		4 hr		10 hr		4 hr		10 hr	
		2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
Fixed O&M (\$/kW-yr)		[14.51-17.73] 16.12				[8.84-10.80] 9.82				[7.87-9.61] 8.74			
Variable O&M (\$/MWh)		0.5125				0.5125				0.5125			
System RTE Losses (\$/kWh)		0.0005				0.0005				0.0005			
Performance Metrics		100 MW				1,000 MW				10,000 MW			
		4 hr		10 hr		4 hr		10 hr		4 hr		10 hr	
		2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
Round Trip Efficiency (%)		52%				52%				52%			
Response Time (sec)		Scenario						Response Time					
		Cold start to full generation						10 minutes					
		Online to full power						5 minutes					
		Full speed (no load) to full load						3.33 minutes					
		Offline to full load						4 minutes					
Cycle Life (#)		10,403				10,403				10,403			
Calendar Life (yrs)		30				30				30			
Duration Corresponding to Cycle Life** (yrs)		30				30				30			
*Does not include warranty, insurance, or decommissioning costs													
** Assumes 80% depth of discharge, one cycle/day, and 5% downtime													

*Does not include warranty, insurance, or decommissioning costs

**Assumes 80% depth of discharge, one cycle/day, and 5% downtime

84 2020 Grid Energy Storage Technology Cost and Performance Assessment (Rep. No. Publication No. DOE/PA-0204). (2020, December). Retrieved April 22, 2021, from 2020 Grid Energy Storage Technology Cost and Performance Assessment, <https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf>



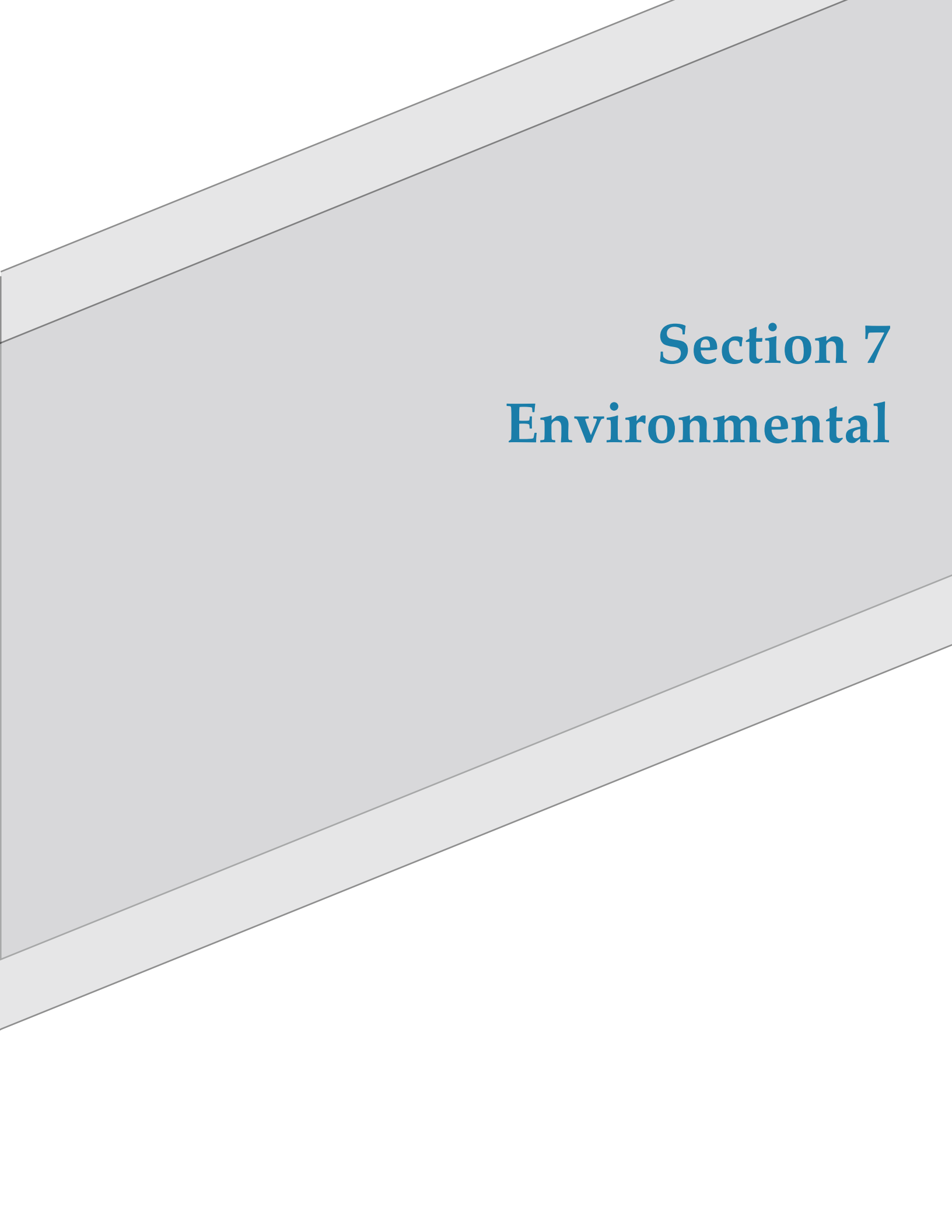
Figure 6.15-6 illustrates the expected continued decline in the cost of solar, wind, and batteries. The decline is driven by experience curves. An experience curve is simply the mathematical relationship that describes the cost reduction of a manufactured product as a function of total cumulative production. As a more mature technology, the nominal wind cost is expected to decline 0.68% annually over the next 20 years, while the solar cost is expected to decline 1.33% and the battery cost is expected to decline 3.05%. Supply chain issues may put upward pressure on cost, while additional or extended government subsidies will put downward pressure on cost.

Table 6.15-6: Solar, Wind, and Battery Price Outlook Table

Year	Kentucky Area				Indiana Area					
	Solar Cost (\$/MWh)				Wind Cost (\$/MWh)				Battery (\$/kW)	
	30 MW	60 MW	90 MW	120 MW	30 MW	60 MW	90 MW	120 MW	4 Hour	10 Hour
2022	\$ 42.00	\$ 38.50	\$ 35.00	\$ 32.00	\$ 51.82	\$ 47.50	\$ 43.18	\$ 39.48	\$ 1,832.15	\$ 3,914.72
2023	\$ 41.40	\$ 37.95	\$ 34.50	\$ 31.54	\$ 51.30	\$ 47.03	\$ 42.75	\$ 39.09	\$ 1,723.09	\$ 3,681.70
2024	\$ 40.80	\$ 37.40	\$ 34.00	\$ 31.09	\$ 50.82	\$ 46.58	\$ 42.35	\$ 38.72	\$ 1,614.04	\$ 3,448.68
2025	\$ 40.21	\$ 36.86	\$ 33.50	\$ 30.63	\$ 50.34	\$ 46.15	\$ 41.96	\$ 38.36	\$ 1,526.79	\$ 3,262.26
2026	\$ 39.62	\$ 36.32	\$ 33.01	\$ 30.18	\$ 49.90	\$ 45.74	\$ 41.58	\$ 38.02	\$ 1,439.55	\$ 3,075.85
2027	\$ 39.03	\$ 35.78	\$ 32.52	\$ 29.74	\$ 49.46	\$ 45.34	\$ 41.22	\$ 37.69	\$ 1,374.11	\$ 2,936.04
2028	\$ 38.44	\$ 35.24	\$ 32.03	\$ 29.29	\$ 49.05	\$ 44.96	\$ 40.88	\$ 37.37	\$ 1,308.68	\$ 2,796.23
2029	\$ 37.86	\$ 34.70	\$ 31.55	\$ 28.84	\$ 48.65	\$ 44.60	\$ 40.54	\$ 37.07	\$ 1,221.43	\$ 2,609.81
2030	\$ 37.28	\$ 34.17	\$ 31.06	\$ 28.40	\$ 48.28	\$ 44.26	\$ 40.23	\$ 36.79	\$ 1,156.00	\$ 2,470.00
2031	\$ 36.85	\$ 33.78	\$ 30.70	\$ 28.07	\$ 47.92	\$ 43.93	\$ 39.93	\$ 36.51	\$ 1,134.19	\$ 2,423.40
2032	\$ 36.42	\$ 33.38	\$ 30.34	\$ 27.74	\$ 47.59	\$ 43.62	\$ 39.65	\$ 36.25	\$ 1,134.19	\$ 2,423.40
2033	\$ 35.99	\$ 32.99	\$ 29.99	\$ 27.42	\$ 47.27	\$ 43.33	\$ 39.38	\$ 36.01	\$ 1,112.38	\$ 2,376.79
2034	\$ 35.57	\$ 32.61	\$ 29.64	\$ 27.10	\$ 46.96	\$ 43.05	\$ 39.13	\$ 35.77	\$ 1,112.38	\$ 2,376.79
2035	\$ 35.15	\$ 32.22	\$ 29.29	\$ 26.78	\$ 46.68	\$ 42.79	\$ 38.89	\$ 35.56	\$ 1,090.57	\$ 2,330.19
2036	\$ 34.73	\$ 31.84	\$ 28.94	\$ 26.46	\$ 46.41	\$ 42.54	\$ 38.67	\$ 35.35	\$ 1,090.57	\$ 2,330.19
2037	\$ 34.31	\$ 31.45	\$ 28.59	\$ 26.14	\$ 46.16	\$ 42.31	\$ 38.46	\$ 35.16	\$ 1,068.75	\$ 2,283.58
2038	\$ 33.89	\$ 31.07	\$ 28.24	\$ 25.82	\$ 45.93	\$ 42.10	\$ 38.26	\$ 34.99	\$ 1,046.94	\$ 2,236.98
2039	\$ 33.48	\$ 30.69	\$ 27.90	\$ 25.51	\$ 45.71	\$ 41.90	\$ 38.09	\$ 34.82	\$ 1,025.13	\$ 2,190.38
2040	\$ 33.07	\$ 30.32	\$ 27.56	\$ 25.20	\$ 45.52	\$ 41.72	\$ 37.92	\$ 34.68	\$ 1,003.32	\$ 2,143.77
2041	\$ 32.62	\$ 29.90	\$ 27.18	\$ 24.85	\$ 45.34	\$ 41.56	\$ 37.77	\$ 34.54	\$ 1,003.32	\$ 2,143.77
2042	\$ 32.17	\$ 29.49	\$ 26.80	\$ 24.51	\$ 45.17	\$ 41.40	\$ 37.63	\$ 34.41	\$ 981.51	\$ 2,097.17

* Nominal Cost

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Section 7

Environmental

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7. ENVIRONMENTAL

The IRP is a resource planning activity designed to identify KYMEA's near and long-term power supply. The process of developing the IRP includes an analysis of environmental policy and trends that influence various aspects of power supply.

During the research and analysis process, a number of environmental concerns were identified, including some raised by the public. KYMEA has committed to reducing its carbon footprint by entering into a 20-year PPA with the Ashwood Solar I Project for 54 MW of solar generation, amounting to 9% of KYMEA's overall energy mix.

With the beginning of the Biden administration, it is expected that U.S. federal environmental policies will be reviewed and revised to align with Mr. Biden's environmental plans. The actions of the new administration to rejoin the Paris Agreement, as Mr. Biden promised in his presidential campaign, are recent examples.

Figure 7-1 demonstrates key action items that are necessary to obtain net-zero carbon emissions by 2050.

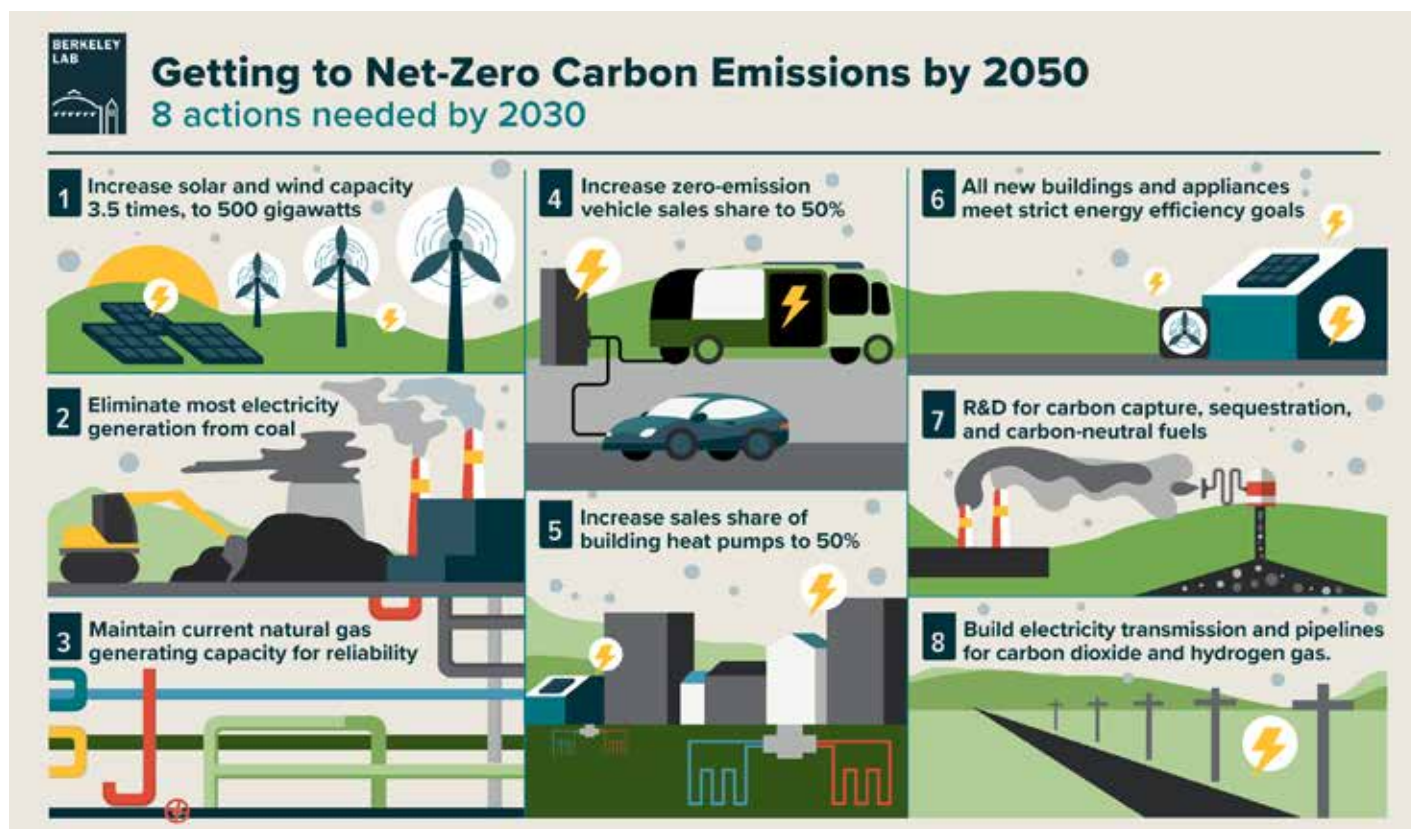


Figure 7-1: Getting to Net-Zero Carbon Emissions by 2050⁸⁵

85 Chao, J. (2021, January 27). Getting to net zero – and even net negative – is surprisingly feasible, and affordable. Retrieved April 22, 2021, from <https://newscenter.lbl.gov/2021/01/27/getting-to-net-zero-and-even-net-negative-is-surprisingly-feasible-and-affordable/>



7.1 Clean Air Act - Six Common Air Pollutants

The CAA requires the Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) for six common air pollutants.

Ground-Level Ozone

Ozone can be good or bad for health and the environment, depending on where it is found in the atmosphere. Stratospheric ozone is beneficial because it protects living things from ultraviolet radiation from the sun. Ground-level ozone is detrimental because it can trigger a variety of health problems, particularly for children, the elderly, and people of all ages who have lung diseases such as asthma.

Particulate Matter (PM)

Particulate matter is the mixture of solid particles and liquid droplets found in the air. They are regulated by their size. Larger particles, called PM₁₀, are related to activities that create dust. Smaller particles, known as PM_{2.5}, are related to the burning of fuels and are commonly called soot.

Carbon Monoxide (CO)

Carbon monoxide is a colorless, odorless gas that can be harmful when inhaled in large amounts. CO is released when a substance is burned. The greatest contributors of CO in outdoor air are cars, trucks, and other vehicles or machinery that burn fossil fuels. A variety of household items such as un-vented kerosene and gas space heaters, leaking chimneys and furnaces, and gas stoves also release CO and can affect air quality indoors.

Lead (Pb)

Lead is a naturally occurring element found in small amounts in the earth's crust. While it has some beneficial uses, it can be toxic to humans and animals, causing health effects. Lead can be found in all parts of our environment – the air, the soil, the water, and even inside our homes. Much of our exposure comes from human activities, including the use of fossil fuels, past use of leaded gasoline, industrial facility contamination, and use of lead-based paint in homes. In the past, lead and lead compounds have been used in a wide variety of household products, including paint, ceramics, pipes and plumbing materials, solders, gasoline, batteries, ammunition, and cosmetics.

Nitrogen Oxide (NO_x)

Nitrogen oxides are highly reactive gases that form when fuel is burned at high temperatures. It appears in a brownish color and can also be referred to as smog.

Sulfur Dioxide (SO₂)

Sulfur dioxide is part of a group of chemicals called sulfur oxides (SO_x). These gases are emitted by the burning of fossil fuels or other materials that contain sulfurs. Once released into the air, they can also create secondary pollutants such as sulfate aerosols, particulate matter, and acid rain.



7.2 Clean Air Act - Regulations

Since the CAA of 1970 was signed into law by President Nixon, there have been several EPA programs to address the six common air pollutants described in Section 7.1. While the programs affect fossil fuels, they are most impactful for coal-fueled power plants.

Acid Rain Program (ARP)

The Acid Rain Program (ARP), established under Title IV of the 1990 CAA Amendments requires major emission reductions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x), the primary precursors of acid rain, from the power sector. The SO₂ program sets a permanent cap on the total amount of SO₂ that may be emitted by electric generating units (EGUs) in the contiguous United States. The program was phased in, with the final 2010 SO₂ cap set at 8.95 million tons, a level of about one-half of the emissions from the power sector in 1980. NO_x reductions under the ARP are achieved through a program that applies to a subset of coal-fired EGUs and is closer to a traditional, rate-based regulatory system.

The ARP was the first national cap and trade program in the country, and it introduced a system of allowance trading that uses market-based incentives to reduce pollution. Reducing emissions using a market-based system provides regulated sources with the flexibility to select the most cost-effective approach to reduce emissions.

Clean Air Interstate Rule (CAIR)

EPA's Clean Air Interstate Rule (CAIR) addressed regional interstate transport of soot (fine particulate matter) and smog (ozone). CAIR required 28 eastern states to make reductions in sulfur dioxide (SO₂) and nitrogen oxides (NO_x) emissions that contribute to unhealthy levels of fine particle and ozone pollution in downwind states. CAIR was replaced by the Cross-State Air Pollution Rule as of January 1, 2015.

Cross-State Air Pollution Rule (CSAPR)

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to address air pollution from upwind states that cross state lines and affect air quality in downwind states. Sulfur dioxide (SO₂) and oxides of nitrogen (NO_x) emissions react in the atmosphere and contribute to the formation of fine particle (soot) pollution. NO_x also contributes to ground-level ozone (smog) formation.

CSAPR requires certain states in the eastern half of the U.S. to improve air quality by reducing power plant emissions crossing state lines and contributing to smog and soot pollution in downwind states. These improvements help areas downwind attain and maintain EPA's health-based soot and smog air quality standards contained in NAAQS.

On September 7, 2016, the EPA revised the CSAPR ozone season NO_x program by finalizing an update to CSAPR for the 2008 ozone NAAQS, known as the CSAPR Update. The CSAPR Update ozone season NO_x program will largely replace the original CSAPR ozone season NO_x program starting on May 1, 2017. The CSAPR Update will further reduce summertime NO_x emissions from power plants in the eastern U.S.

Maximum Achievable Control Technology (MACT) Rule

The United States CAA legally mandated the EPA to regulate the emission of hazardous air pollutants (HAPs) by industrial sources. To accomplish this mandate, the EPA developed MACT - Maximum Achievable Control Technology - standards. MACT standards use the HAP emissions of the best-performing (thus, "Maximum Achievable") industry sources to set the "MACT floor," the new minimum standard that an industry must at least meet in order to comply.



The concept of control technology is not just limited to actual technology, but it also encompasses the processes, methods, systems, and techniques that are used in facilities to reduce their HAP emissions. Under MACT standards, the technology and work practices in facilities that produce the lowest HAP emissions are used to set the standards for the rest of the industry.

Ozone Rule

On December 23, 2020, EPA completed its review of the full body of currently available scientific evidence and exposure/risk information and decided to retain the existing ozone NAAQS. EPA's decision is based on its judgment that the current NAAQS protect the public health, with an adequate margin of safety, including the health of at-risk populations, and protect the public welfare from adverse effects. The existing primary and secondary standards, established in 2015, are 0.070 parts per million (ppm), as the fourth-highest daily maximum 8-hour concentration, averaged across three consecutive years.

Coal Combustion Residuals (CCR) Rule

On December 19, 2014, the EPA Administrator signed a final rule that establishes a comprehensive set of requirements for the disposal of coal combustion residuals (CCRs or coal ash) in landfills and surface impoundments. These requirements have been finalized under the solid waste provisions, subtitle D, of the Resource Conservation and Recovery Act.

Mercury and Air Toxics Standards (MATS) Rule

On May 22, 2020, the EPA published the completed reconsideration of the appropriate and necessary finding for the Mercury and Air Toxics Standards, correcting flaws in the 2016 supplemental cost finding while ensuring that power plants will emit no more mercury to the air than before. After primarily considering compliance costs relative to the HAP benefits of MATS, EPA concluded that it is not appropriate and necessary to regulate electric utility steam generating units under section 112 of the CAA.

EPA Regulatory Timeline for Coal-Fueled Power Plants

The described rules are not a complete listing of all the environmental rules, but merely a list of the most significant rules. Figure 7.2-1 demonstrates the timeline of the EPA's regulations for Coal-Fueled Power Plants and Commercial Industrial Boilers beginning in 2008. The purpose of this timeline is to show identified rules that were being developed by the EPA, and a potential schedule for implementation from 2008-2017. Entries on the timeline primarily relate to air pollution, which is where coal-fired plants would be impacted heavily from the proposed rules; however, water pollution and solid waste residuals are included in several entries as well. Without surprise, this timeline has received both support and criticism in analysis from industry, research, and political groups.



The EPA Regulatory Timeline for Coal-Fueled Power Plants

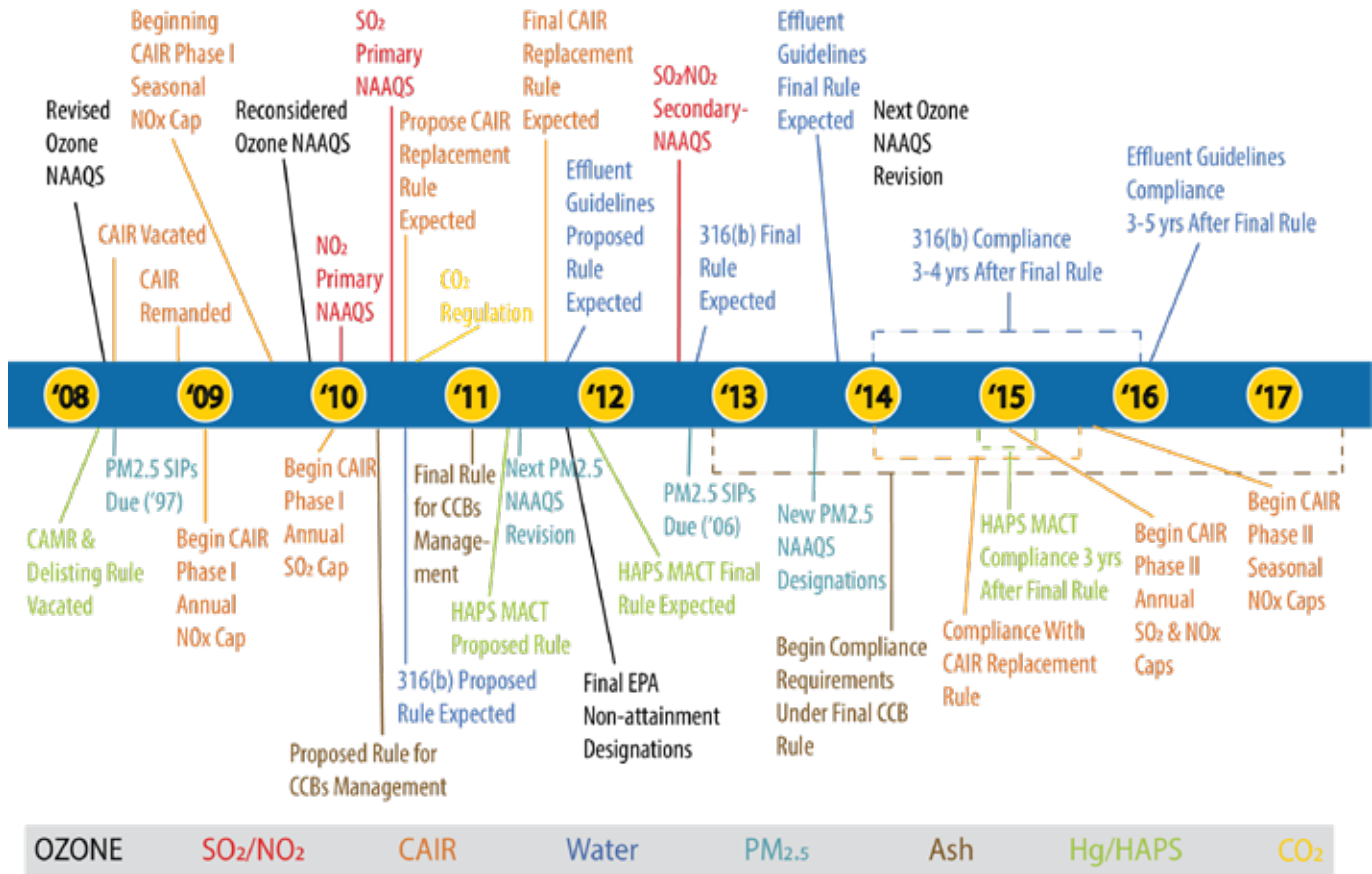


Figure 7.2-1: EPA Regulatory Timeline for Coal-Fueled Power Plants



States Covered by EPA Regulations

As shown in Figure 7.2-2, the lower 48 states are impacted differently by the EPA regulations. States east of the Rocky Mountains experience more stringent regulations due to the Transport Rule. The Transport Rule aims to limit pollution that drifts from upwind states into neighboring downwind states.

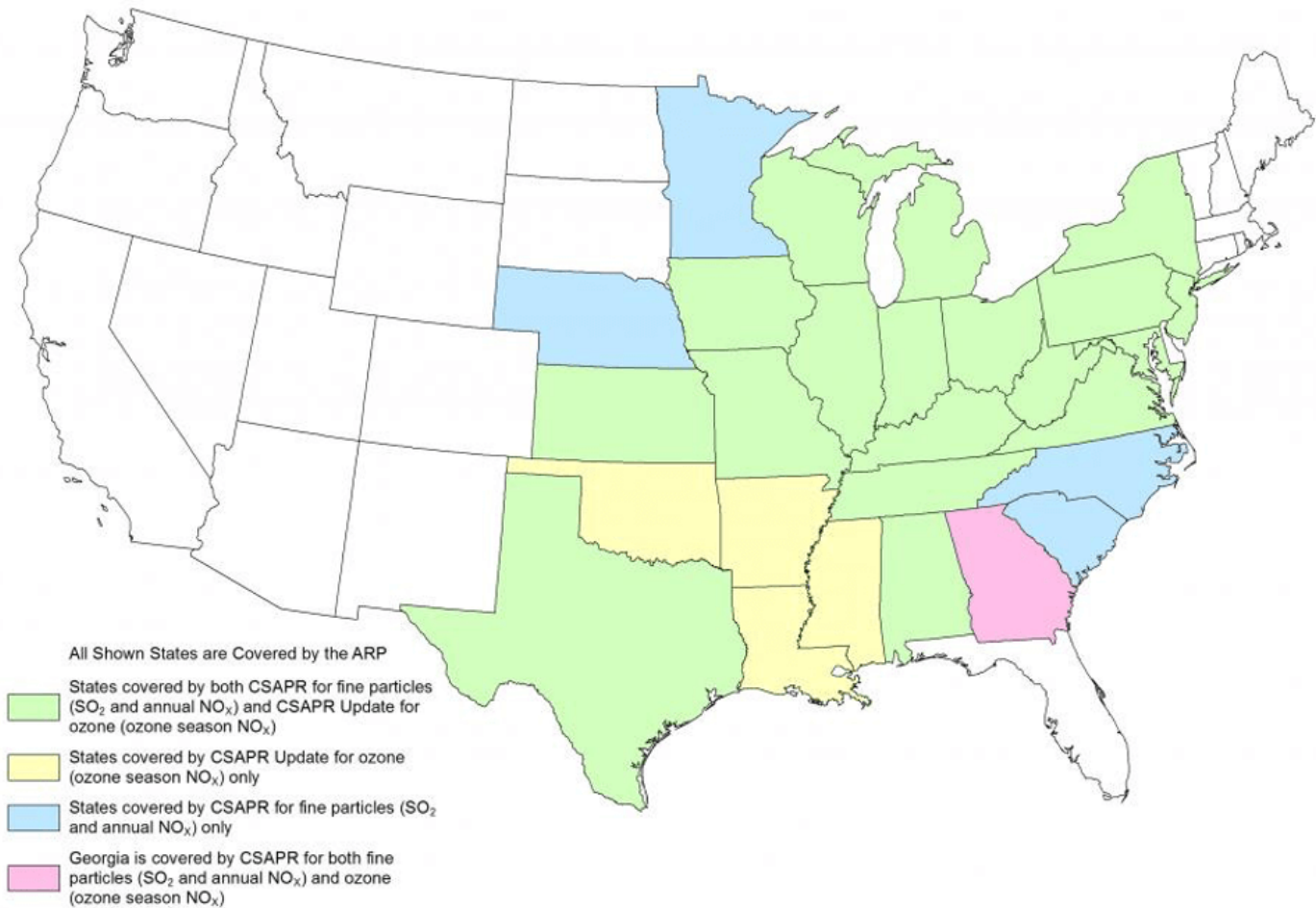


Figure 7.2-2: States Covered by EPA Regulations⁸⁶

86 Center for Climate and Energy Solutions. (n.d.). States Covered by EPA Regulations [Digital image]. Retrieved April 26, 2021, from <https://www.c2es.org/content/regulating-power-sector-carbon-emissions/>



7.3 Regulating Power Sector Carbon Emissions

The EPA has authority under the CAA to monitor and regulate greenhouse gas emissions. The EPA regulates greenhouse gas emissions from power plants under Section 111 of the CAA, which allows the EPA and the states greater flexibility in crafting and implementing a standard. Emissions from new and modified power plants have been finalized under Section 111(b), as described below. Emissions for existing power plants are still being developed under Section 111(d).

New Power Plants Section 111(b)

In December 2018, EPA proposed GHG emission regulations for new, modified, and reconstructed power plants. The proposed rule would replace EPA's 2015 "Carbon Pollution Standard for New Power Plants," which established New Source Performance Standards (NSPS) to limit carbon dioxide emissions from fossil fuel-fueled power plants. The 2015 rule determined:

- New natural gas power plants can emit no more than 1,000 pounds of carbon dioxide per megawatt-hour (MWh) of electricity produced, which is achievable with the latest combined cycle technology.
- New coal power plants can emit no more than 1,400 pounds CO₂/MWh, which almost certainly requires the use of carbon capture and storage (CCS) technology.

The proposed 2018 rule would:

- Set the best system of emissions reduction for newly constructed large units equivalent to a super-critical coal plant, which has an emissions rate of 1,900 lbs CO₂/MWh and would set the best system of emission reductions for small units to 2,000 lbs CO₂/MWh.
- Set separate performance standards for newly constructed and reconstructed coal refuse-fired units at an emissions rate at 2,200 lbs CO₂/MWh.
- Revise the standards of performance for reconstructed power plants to be consistent with the emission rates of newly constructed units.

This standard was adopted under Section 111(b) of the CAA, which applies to new, modified, and reconstructed power plants, and requires EPA to set a numerical performance standard based on the best available technology that has been adequately demonstrated. States have little flexibility in applying the standard.

Existing Power Plants Section 111(d)

The following excerpt, highlighted in blue, is from Beveridge & Diamon, February 4, 2021.

On January 19, 2021, the D.C. Circuit vacated the Affordable Clean Energy (ACE) rule, the Trump Administration's action to address CO₂ emissions from existing coal-fired power plants. The ACE rule repealed an Obama-era rule known as the Clean Power Plan and replaced it with the less stringent requirements. Both rules were adopted under CAA section 111(d), and both were the subject of fierce litigation by industry, states, and NGOs alike. The D.C. Circuit's decision to vacate the ACE rule opens the door for further regulatory action by the Biden Administration on power plant greenhouse gas emissions.



Key Takeaways

- Decision vacates ACE rule and remands to EPA to “consider the question afresh.”
- The D.C. Circuit rejected the Trump Administration’s contention that—no matter the circumstances—Section 111 of the CAA unambiguously limits the “best system of emission reduction” to emissions-reducing measures operating at the physical source.
- The court’s decision clears the way for the Biden EPA to issue a replacement rule regulating CO₂ emissions from existing power plants, potentially again considering generation shifting and other measures to more aggressively target power sector emissions.
- President Biden’s choice for EPA Administrator, Michael Regan, testified that he views the opportunity as a “clean slate” for the Agency to chart next steps under Section 111(d).
- EPA will need to carefully consider how it interprets the scope of its statutory authority in light of the ever-present prospect of Supreme Court review, and the heavy litigation likely to ensue over any replacement rule.

Background

EPA promulgated both the ACE rule and its predecessor, the Clean Power Plan, under CAA section 111(d). That provision requires EPA to establish emissions guidelines based on the “degree of emission limitation achievable through application of the best system of emission reduction” that has been “adequately demonstrated” for existing stationary sources of air pollution. The final Clean Power Plan’s “best system of emission reduction” (BSER) was comprised of three “building blocks” identified by EPA as follows:

1. Reducing CO₂ emissions by undertaking efficiency projects at affected coal-fired power plants (i.e., heat-rate improvements)
2. Reducing CO₂ emissions by shifting electricity generation from affected power plants to lower-emitting power plants (e.g., natural gas plants); and
3. Reducing CO₂ emissions by shifting electricity generation from affected power plants to new renewable energy generation.

Notably, the second and third building blocks—responsible for the vast majority of projected emissions reductions—were heavily premised on “beyond the fence line measures” to reduce emissions. (EPA had also proposed demand-side energy efficiency measures as a fourth BSER building block, but did not include them in the final Clean Power Plan’s BSER determination and instead allowed them only as a “non-BSER” method of compliance.)

The final Clean Power Plan was immediately challenged. Among other things, the Clean Power Plan’s opponents argued that the rule exceeded EPA’s authority under Section 111(d), primarily because the BSER was based on measures operating beyond the fence line of individual power plants.

In February 2016, in a 5-4 decision, the Supreme Court stayed the Clean Power Plan while the rule was being challenged in the D.C. Circuit. The full D.C. Circuit heard oral arguments in September 2016, but the court never issued a decision. Instead, the newly elected Trump Administration quickly moved to hold the case in abeyance and—once repeal of the Clean Power Plan was complete—the D.C. Circuit dismissed the litigation as moot.

In 2019, the Trump EPA simultaneously repealed the Clean Power Plan and finalized the ACE rule. The ACE rule focused primarily on improvements in the efficiency of combustion of fossil fuels at coal-fired power plants, based on the premise that the CAA limits the “best system of emission reduction” to measures that can be applied “at and to the source”—i.e., within the fence line. Whereas EPA projected that the Clean Power Plan would have reduced power sector CO₂ emissions 32% by 2030, EPA projected that the ACE rule would reduce emissions by less than 1% from baseline emission projections by 2035.

The emissions limitations contained in the ACE rule included three primary components:



1. A determination that the only permissible interpretation of Section 111 limits the BSER for CO₂ emissions from coal-fired power plants to heat-rate improvements, which can be applied to or at an individual plant and are therefore inside the fence line
2. A list of candidate technologies states could use when developing their implementation plans; and
3. New implementing regulations for emission guidelines under Section 111(d).

As with the Clean Power Plan, numerous groups immediately filed petitions challenging the ACE rule in the D.C. Circuit.

D.C. Circuit's Decision

The key statutory question under review was the scope of emissions control measures achievable by power plants through the application of the best system of emission reduction under Section 111. The court grappled with the breadth of EPA's authority to set the BSER, and whether it was constrained to inside the fence line measures. In its 147-page majority opinion, the D.C. Circuit held that the ACE rule must be vacated because it rested on a "fundamental misconstruction" of Section 111(d) as unambiguously limiting BSER to inside-the-fence-line measures.

The Trump EPA had used its statutorily constrained position to justify the ACE rule's exclusive reliance on heat-rate improvement measures as the BSER. If successful, that argument may have limited the ability of groups to push for a BSER comprised of more stringent outside-the-fence-line measures, or tied the hands of a future EPA to consider such measures. According to the court, the "shortcomings of [EPA's] statutory interpretation are more than enough to doom the agency's claim that Section [111] announces an unambiguous limit on the best system of emission reduction."

The court also observed that the ACE rule would have required EPA to ignore more cost-effective methods of emission reduction:

"The record before the EPA shows that generation shifting to prioritize use of the cleanest sources of power is one of the most cost-effective means of reducing emissions that plants have already adopted and that have been demonstrated to work, and that generation shifting is capable of achieving far more emission reduction than controls physically confined to the source. In other words, the EPA reads the statute to require the Agency to turn its back on major elements of the systems that the power sector is actually and successfully using to efficiently and cost-effectively achieve the greatest emission reductions."

The court weighed these facts in its ultimate finding that the ACE rule's interpretation of BSER was inconsistent with the history, structure, and purpose of Section 111. The court also rejected EPA's largely policy-based arguments for prohibiting the use of averaging and trading, or of biomass co-firing, as compliance measures.

The dissenting opinion by Judge Walker stated that EPA was correct to repeal the Clean Power Plan under the major rules doctrine, which requires that an agency have a clear grant of statutory authority for rules with "vast economic and political significance." The dissent also would have found that EPA does not have the authority to regulate carbon emissions from coal-fired power plants because it already regulates mercury emissions from those plants under Section 112. This argument is based on a mistake during congressional negotiations of Section 111(d) that resulted in two versions of the same provision being included in the final law.

After a lengthy statutory interpretation analysis, the D.C. Circuit vacated the ACE rule and remanded to the EPA to consider again.

Outlook

While it is possible the Supreme Court could review the D.C. Circuit's decision, this seems unlikely given the Biden Administration would oppose review and is likely to undertake a new rulemaking process to adopt a program that may be a significant departure from both the ACE rule and the Clean Power Plan.



The next likely step will be for the Biden EPA to draft a new rule addressing power plant GHG emissions, in light of both technological advances and a federal judiciary more skeptical of agency rulemaking authority.

Indeed, at his February 3, 2021 confirmation hearing to serve as EPA Administrator, Michael Regan was asked whether the Biden Administration “intends to come back with a new version of the Clean Power Plan.” He responded that although EPA would review the work underlying the ACE Rule and the Clean Power Plan, the Agency now has a “significant opportunity to take a clean slate” in charting its next steps.

There is little doubt the Biden Administration will pursue an aggressive approach on climate matters, given that the Biden Administration has made clear that greenhouse gas regulations are a priority. On his first day in office, President Biden signed an executive order titled, “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,” which directs EPA and all other federal agencies to “immediately commence work to confront the climate crisis.” One week later, on January 27, 2021, President Biden issued an “Executive Order on Tackling the Climate Crisis at Home and Abroad.” The order says that “we face a climate crisis that threatens our people and communities, public health and economy, and, starkly, our ability to live on planet Earth.” The Biden EPA will likely not waste time in crafting a replacement for the ACE rule.

By opening the door to consideration of beyond the fence line measures, the D.C. Circuit’s decision creates an opening for the Biden EPA to consider a broad range of approaches to new regulations targeting CO₂ emissions from fossil fuel-fired power plants. The Biden EPA could also consider broadening the scope of affected sources to include certain oil- and gas-fired power plants, as had been the case with the Clean Power Plan. New regulations of this kind may take advantage of post-2015 developments in the power sector that have further reduced the cost of low- and zero-GHG sources of electricity. Indeed, calculated nationally, the Clean Power Plan’s interim reduction targets for 2025 were achieved in 2017—eight years earlier than projected, and without the Clean Power Plan in effect.

Although the D.C. Circuit’s decision to vacate the ACE rule spares the Biden EPA the time-consuming process of repealing it, any new rule will certainly be challenged. The Biden EPA must weigh its strategy carefully in deciding which measures to include in the BSER and in compliance matters—whether it’s generation shifting, emissions trading, demand-side energy efficiency, co-firing, or even carbon capture and sequestration—to ensure it crafts a workable and legally-defensible rule.⁸⁷

Paris Agreement on Climate Change

Adopted in Paris on December 12, 2015, and enacted on November 4, 2016, the Paris Agreement on Climate Change was adopted by 196 United Nations Framework Convention on Climate Change (UNFCCC) Parties. The agreement’s goal is to limit global warming to an increase of less than 1.5 degrees Celsius per year. The agreement was initially signed by President Obama in 2015. The Trump administration issued a withdrawal notification on November 4, 2019, which became effective one year later. President Biden promised that with his election as the new President, he would rejoin the Paris Agreement immediately. He rejoined his first day in office, January 20, 2021, readmitting the U.S. effective 30 days later.

87 Brook Detterman, E. (2021, February 4). D.C. Circuit Vacates Trump Ace Rule: What’s next for power Plant CO₂ Regulation? Retrieved May 06, 2021, from <https://www.bdlaw.com/publications/d-c-circuit-vacates-trump-ace-rule-whats-next-for-power-plant-co2-regulation/>



7.4 Tracking Subregion Emissions

The EPA's Emission & Generation Resource Integrated Database (eGRID) is a comprehensive source of various environmental data on electric power generation. The information is broken down and displayed for customers to compare subregions against each other and the nation. A map of eGRID subregions is displayed in Figure 7.4-1.

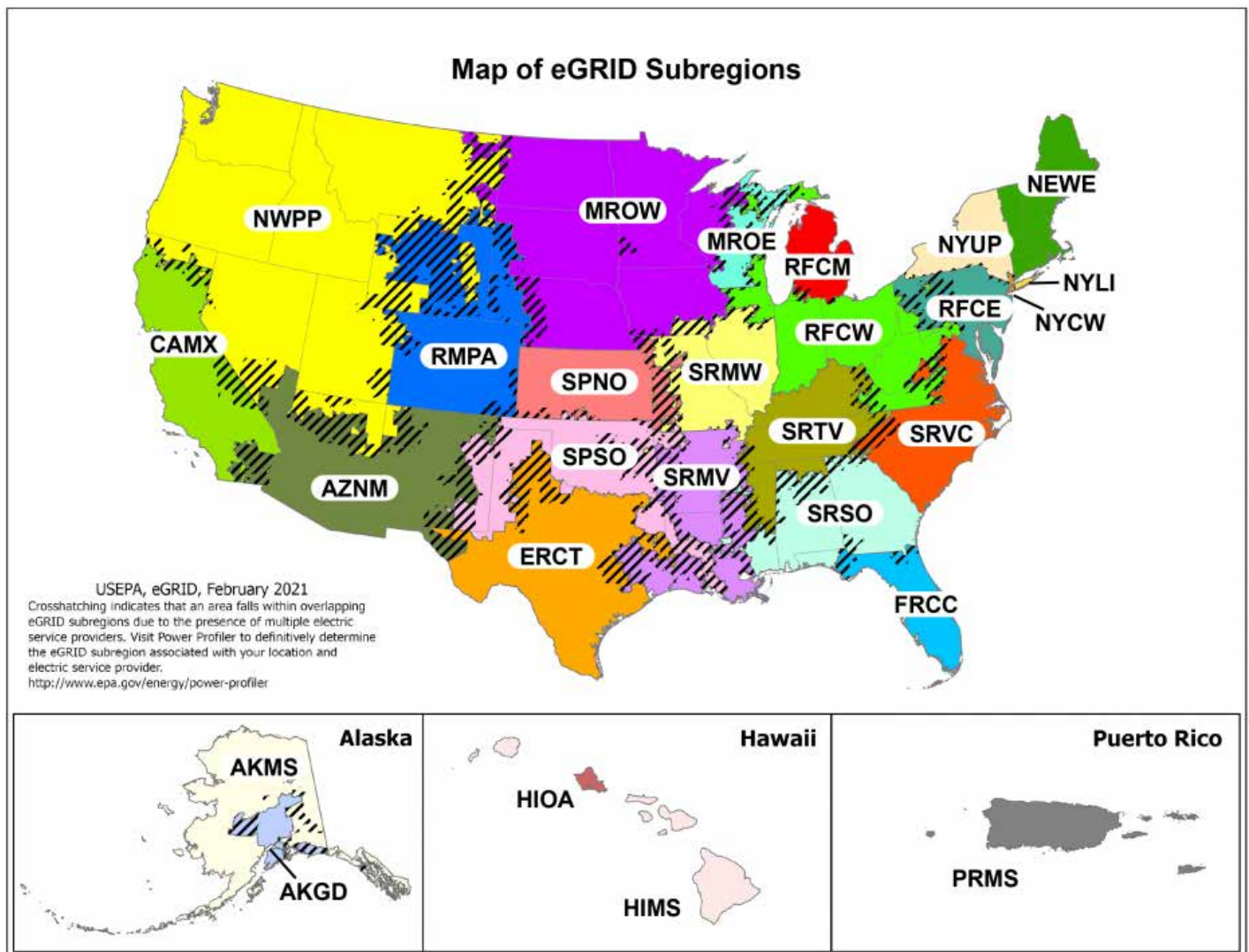


Figure 7.4-1: Map of eGRID Subregions - EPA⁸⁸

88 Map of eGRID Subregions [Digital image]. (2021, February). Retrieved April 22, 2021, from https://www.epa.gov/sites/production/files/styles/large/public/2021-02/2019_egrid_subregions.png



The type and amount of emissions produced in a subregion is related to how electricity is generated in that subregion. KYMEA is part of the SRTV subregion. The SERC - TVA subregion or SRTV is comprised primarily of the TVA and LGE/KU balancing areas. Figures 7.4-2 through 7.4-5 from the eGrid breaks down the SRTV subregion fuel mix as well as CO₂, SO₂, and NO_x emission rates (lbs/MWh) compared to the national average.

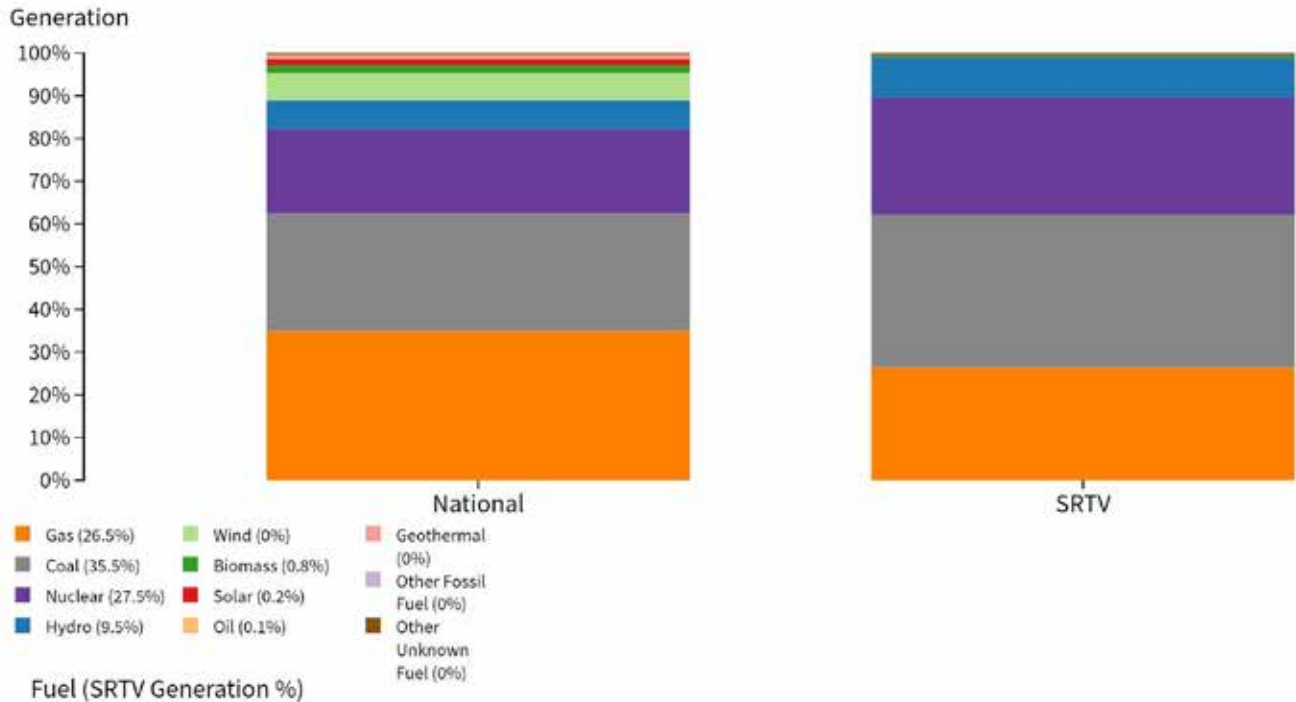


Figure 7.4-2: SRTV Subregion 2019 Generation Mix - eGRID⁸⁹

89 EPA. (n.d.). Retrieved April 22, 2021, from <https://www.epa.gov/egrid/power-profiler#/SRTV>.

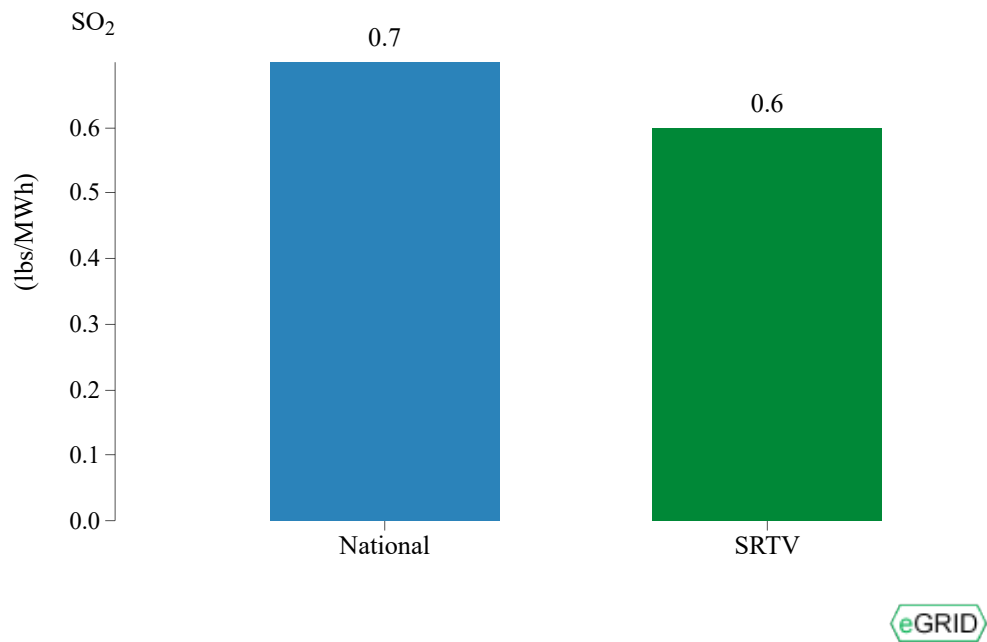


Figure 7.4-3: SRTV Subregion SO₂ Emissions (lbs/MWh) - eGRID⁹⁰

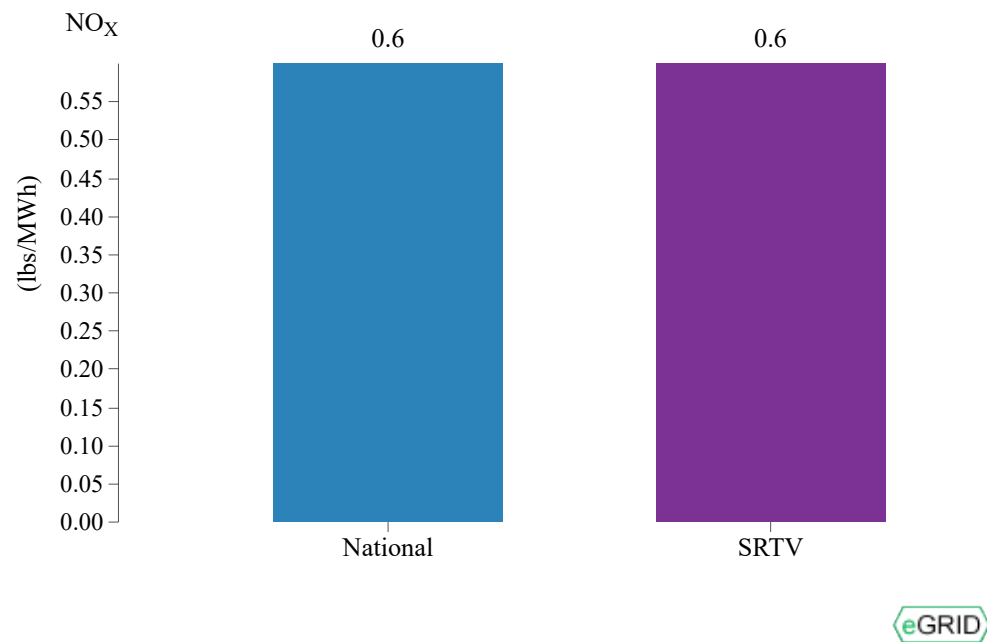


Figure 7.4-4: SRTV Subregion NO_x Emissions (lbs/MWh) - eGRID⁹¹

90 EPA. (n.d.). Retrieved April 22, 2021, from <https://www.epa.gov/egrid/power-profiler#/SRTV>.

91 EPA. (n.d.). Retrieved April 22, 2021, from <https://www.epa.gov/egrid/power-profiler#/SRTV>.

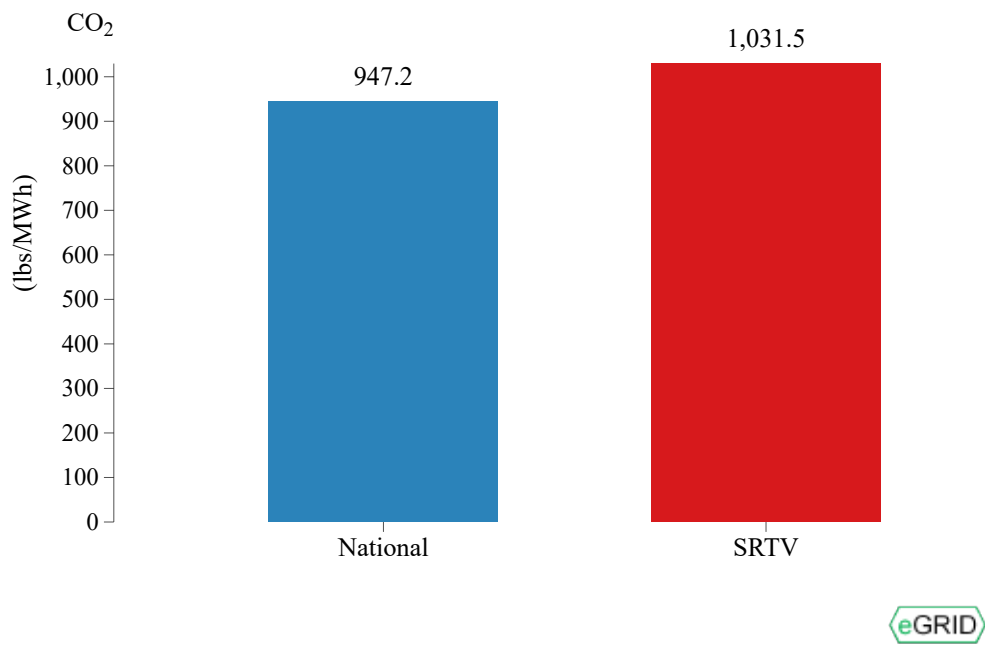


Figure 7.4-5: SRTV Subregion 2018 CO2 Emissions (lbs/MWh) - eGRID92

Figure 7.4-6 is a projection of the carbon intensity in lb/MWh for the entire U.S. as well as the SRTV region from the Horizons Energy Spring 2020 Status Quo scenario, which is further described in Sections 10 and 12 of this report.

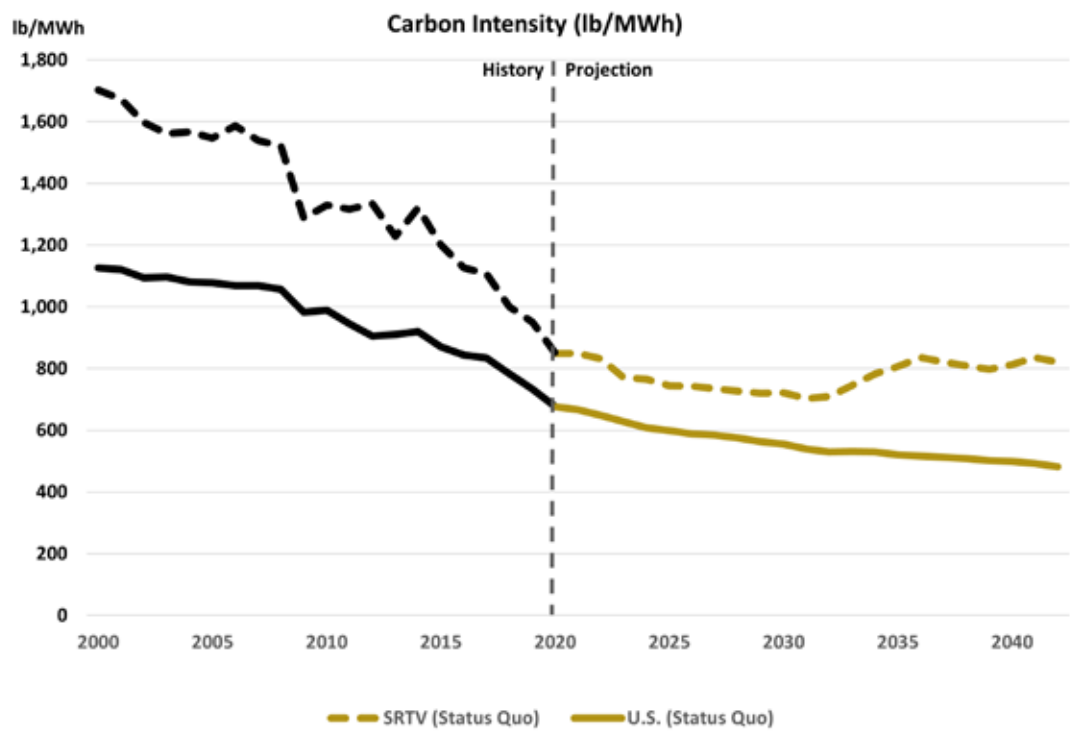
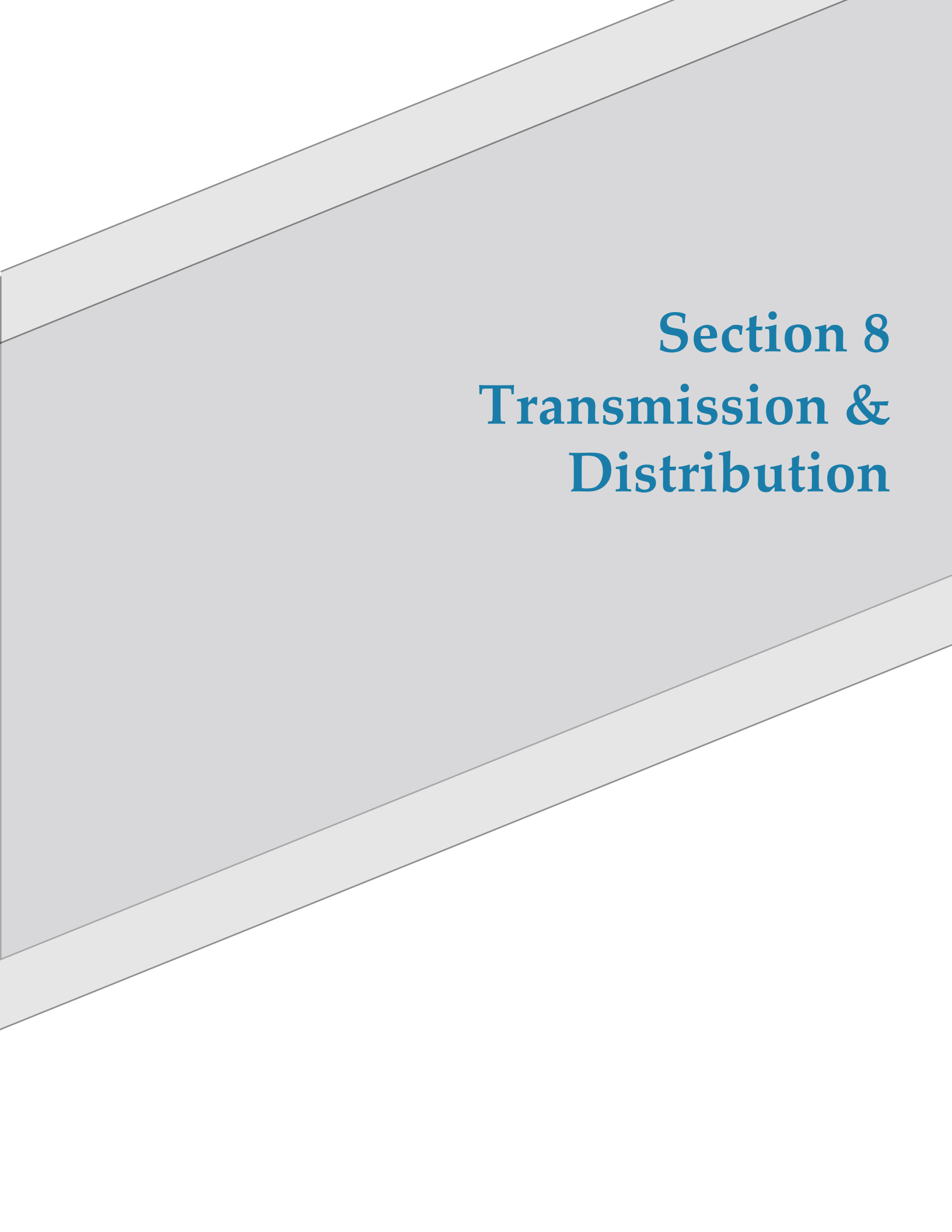


Figure 7.4-6: Carbon Intensity

92 EPA. (n.d.). Retrieved April 22, 2021, from <https://www.epa.gov/egrid/power-profiler#/SRTV>.



Section 8

Transmission & Distribution

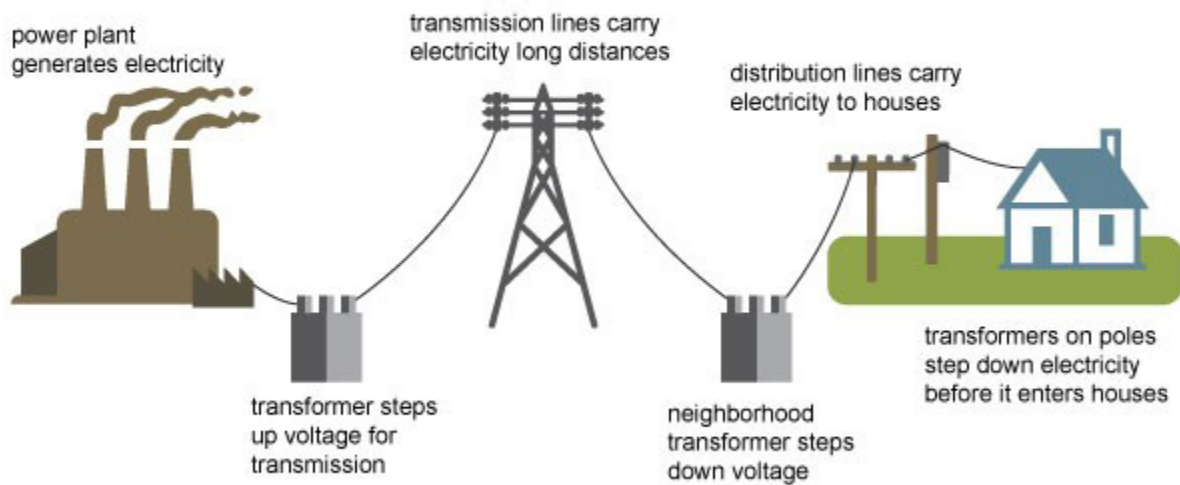
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8. TRANSMISSION & DISTRIBUTION

Electricity produced at power plants travels through a complex grid consisting of power lines, transformers, and substations to connect power supply to end-use consumers. The U.S. grid is comprised of hundreds of thousands of miles of high-voltage transmission lines and millions of miles of low-voltage lines. Medium and high voltage transmission lines range in voltages from 34kV to 765kV. Higher voltage levels allow for more efficient transmission over long distances. The higher the voltage, the lower the current, which results in fewer losses. This also allows for lighter conductors to be used, which in turn, reduces construction costs. This basic framework can be seen in Figure 8-1.

Electricity generation, transmission, and distribution



Source: Adapted from National Energy Education Development Project (public domain)

Figure 8-1: Diagram of Electricity Generation, Transmission, and Distribution System⁹³

93 National Energy Education Development Project. (n.d.). Electricity explained. Retrieved April 22, 2021, from <https://www.eia.gov/energyexplained/electricity/delivery-to-consumers.php>

8.1 Access to Markets

After World War II, demand for electricity in the U.S. began to grow. As such, utilities began to interconnect themselves to take advantage of economies of scale. These utilities were able to construct large jointly owned facilities to spread out costs, and the interconnection allowed them to lean on each other for reserves during times of outages and higher demand. During this interconnection process, three systems evolved, as shown in Figure 8.1-1.

- The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of the Texas panhandle.
- The Western Interconnection encompasses the area from the Rockies to the west.
- The Electric Reliability Council of Texas (ERCOT) covers most of Texas.

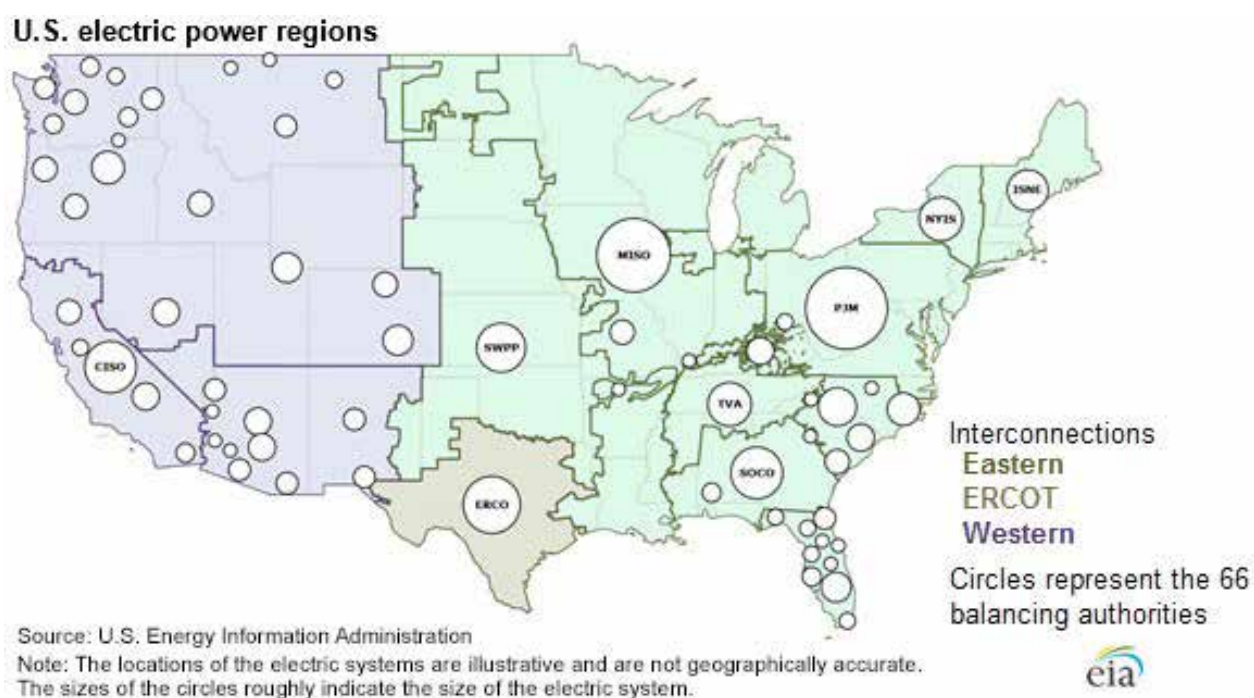


Figure 8.1-1: U.S. Electric Power Regions⁹⁴

These three interconnections make up the U.S. grid in the lower 48 states. Interactions between the interconnections are limited. On a regional basis, BAs manage the constant balance of supply and demand. This is critical for safe and reliable operation of the grid. The standards for grid operations are developed and enforced by NERC. These standards are also approved by FERC. Moving energy between BAs requires rights to use the transmission grid. These rights are procured via submitting transmission service requests. Costs associated with transmission service requests are approved by FERC and are embedded in the provider's tariff. Transmission service requests can be either point-to-point (PTP) or network integrated transmission service (NITS) and can vary in tenor and firmness. The firmness is an indication of priority level, and those are shown in Table 8.1-1.

94 National Energy Education Development Project. (n.d.). Electricity explained. Retrieved April 22, 2021, from <https://www.eia.gov/energyexplained/electricity/delivery-to-consumers.php>

**Table 8.1-1: Transmission Service Reservation Priorities⁹⁵**

Transmission Service Reservation Priorities		
Priority	Acronym	Name
0	NX	Next-hour Market Service
1	NS	Service Over Secondary Receipt and Delivery Points
2	NH	Hourly Service
3	ND	Daily Service
4	NW	Weekly Service
5	NM	Monthly Service
6	NN	Network Integration Transmission Service from sources not designated as network resources
7	F	Firm Point-to-Point Transmission
	FN	Network Integration Transmission Service from Designated Resources

Ten of the eleven KYMEA members' loads reside in the LKE transmission service area. LG&E/KU is the BA for these members. One KYMEA member, Falmouth, resides in the PJM (EKPC) service area. For KYMEA to deliver energy from its resource portfolio to its members' loads, transmission service must be obtained. NITS service on LG&E/KU is required for members whose loads reside in LKE. If resources reside outside of LKE, PTP service would also be required to deliver energy to the LKE interface from the location of the resource. The three available external BAs that KYMEA has access to are MISO, PJM, and TVA. The Falmouth load has unencumbered PJM market access allowing KYMEA to purchase power at the PJM EKPC_RESID_AGG commercial pricing node under the EKPC network transmission service. A summary of KYMEA transmission customers and their respective BAs is shown in Table 8.1-2.

Table 8.1-2: Member's BA and Delivery Voltage

Member	Service	Balancing Authority	Primary Voltage (kV)	Delivery Points
Barbourville	All-Requirements	LG&E/KU	69	1
Bardwell	All-Requirements	LG&E/KU	69	1
Benham	Transmission	LG&E/KU	69	1
Berea	Transmission	LG&E/KU	69	2
Corbin	All-Requirements	LG&E/KU	69	2
Falmouth	All-Requirements	PJM	69	1
Frankfort	All-Requirements	LG&E/KU	69	2
Madisonville	All-Requirements	LG&E/KU	69	6
Paris	All-Requirements	LG&E/KU	69	4
Providence	All-Requirements	LG&E/KU	69	2

95 NERC. (n.d.). Transmission-Service-Reservation-Priorities-/. Retrieved April 22, 2021, from <https://www.nerc.com/pa/rrm/TLR/Pages/Transmission-Service-Reservation-Priorities-.aspx>

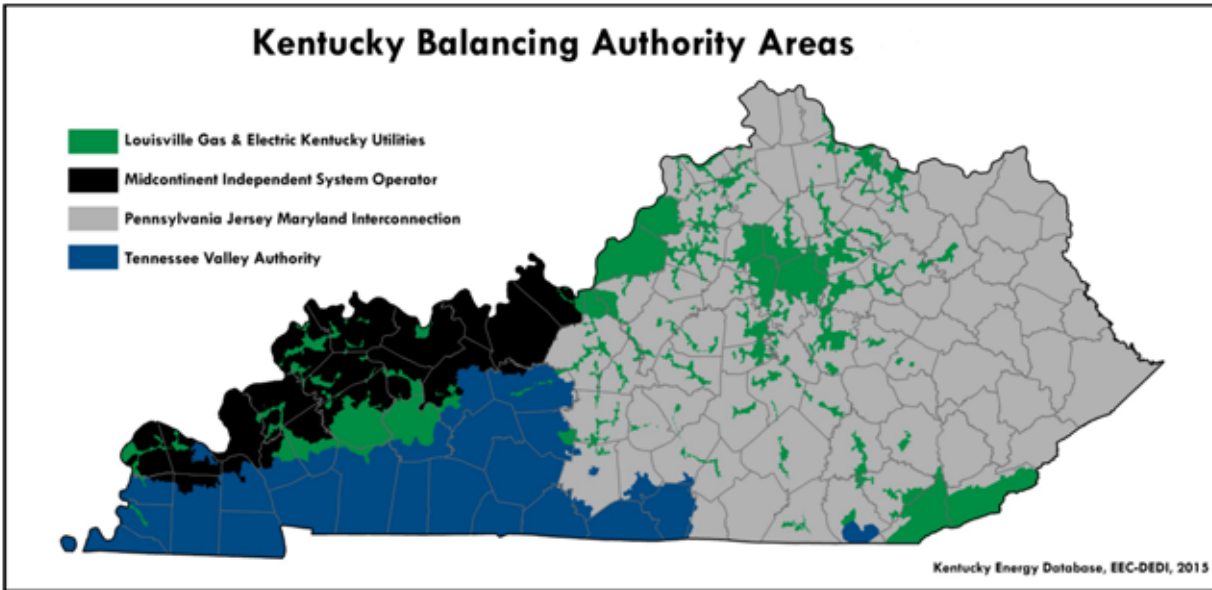
Figure 8.1-2: Kentucky BA Map⁹⁶

Figure 8.1-2 provides a map of Kentucky's BA areas. As mentioned above, for KYMEA to purchase energy from MISO or PJM, point-to-point transmission service has been acquired for the existing portfolio. Any subsequent changes would require either incremental point-to-point transmission service or a redirection of existing service. Table 8.1-3 summarizes KYMEA's transmission portfolio.

Table 8.1-3: KYMEA's Transmission Portfolio

Provider	Source	Sink	Type	Capacity (MW)	Start	Stop	Rollover Rights
MISO	BREC.Wilson.1	LGEE	PTP	100	Present	April 30, 2029	Yes
MISO	BREC.Wilson.1	LGEE	PTP	62	Present	April 30, 2027	Yes
MISO	CIN.Cayuga 1	LGEE	PTP	38	Present	April 30, 2027	Yes
LGEE	GLHB	LGEE.KYMA	NITS	100	Present	May 31, 2022	Yes
LGEE	LGEE.Paris	LGEE.KYMA	NITS	11	Present	May 31, 2029	Yes
LGEE	LGEE.KMPA	LGEE.KYMA	NITS	90	Present	April 30, 2027	Yes
LGEE	MISO	LGEE.KYMA	NITS	38	Present	April 30, 2027	Yes
LGEE	MISO	LGEE.KYMA	NITS	162	Present	April 30, 2027	Yes
LGEE	TVA	LGEE.KYMA	NITS	33	Present	April 30, 2027	Yes
LGEE	Ashwood Solar I	LGEE.KYMA	NITS	54	December 1, 2022	November 30, 2042	Yes
TVA	TVA	LGEE	PTP	33	Present	GF*	GF*

*A grandfather clause (or grandfather policy or grandfathering) is a provision in which an old rule continues to apply to some existing situations while a new rule will apply to all future cases. Those exempt from the new rule are said to have grandfather rights or acquired rights, or to have been grandfathered in.

The scheduling of power from the RTOs is further complicated by import/export RTO hourly ramp availability. Ramp is a BA's ability to accommodate scheduling changes while adhering to the operational limitations of their respective portfolio. Ramp from the RTO's is determined on a first come first served basis.

⁹⁶ Kentucky Energy Profile (7th ed., Rep.). (2019). Kentucky Energy and Environment Cabinet Office of Energy Policy. doi:<https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202019.pdf>



8.2 Buy/Drive-Out Rate Through MISO, PJM, & TVA

Except for the members' Southeastern Power Administration (SEPA) hydroelectric power entitlement, KYMEA cannot purchase power from TVA due to "The Fence." In 1959, an amendment was added to the TVA Act, which created a Fence around TVA. The Fence prohibits TVA from selling power to any municipality which received service from another source on or after July 1, 1957. As such, KYMEA and its members cannot purchase from TVA directly. Opportunities may exist where KYMEA could purchase energy at the TVA interface from enabled counterparties, although this would require incremental transmission costs embedded in the offer price or as a separate purchase of TVA transmission.

The transmission rates, as of the writing of this report, for LG&E/KU, MISO, PJM and TVA are provided in Tables 8.2-1 through 8.2-4.

Table 8.2-1: LG&E/KU Transmission Rates Table

Schedule	Description	\$/MW-MO	\$/MW-WK	On-Peak Rates		Off-Peak Rates	
				\$/MW/Day	\$/MW-HR	\$/MW-Day	\$/MW-HR
1	Scheduling, System Control and Dispatch Service	-	-	-	\$0.11	-	\$0.11
2	Reactive Supply and Voltage Control from Generation Sources Service	\$25.00	\$5.77	\$0.96	\$0.06	\$0.83	\$0.03
3	Regulation and Frequency Response Service	\$6,900.00	\$1,590.00	\$318.00	\$19.90	\$227.00	\$9.50
5	Operating Reserve- Spinning Reserve Service	\$7,130.00	\$1,650.00	\$329.00	\$20.60	\$234.00	\$9.80
6	Operating Reserve- Supplemental Reserve Service	\$7,130.00	\$1,650.00	\$329.00	\$20.60	\$234.00	\$9.80
7	Firm Point to Point	\$2,273.00	\$524.00	\$105.00	-	\$75.00	-
8	Non Firm Point to Point	\$2,273.00	\$524.00	\$105.00	\$6.56	\$75.00	\$3.13
10	Network Integration Service	\$2,282.00	-	-	-	-	-

Table 8.2-2: MISO Transmission Rates Table

Schedule	Description	\$/MW-YR	\$/MW-MO	\$/MW-WK	On-Peak Rates		Off-Peak Rates	
					\$/MW/Day	\$/MW-HR	\$/MW-Day	\$/MW-HR
1	Scheduling, System Control and Dispatch Service	\$849.72	\$70.81	\$16.34	\$3.27	\$0.20	\$2.33	\$0.10
2	Reactive Supply and Voltage Control from Generation Sources Service	\$2,089.28	\$174.11	\$40.18	\$8.04	\$0.50	\$5.72	\$0.24
7	Firm Point to Point	\$44,856.22	\$3,738.02	\$862.62	\$172.52	-	\$122.89	-
8	Non Firm Point to Point	-	\$3,738.02	\$862.62	\$172.52	\$10.78	\$122.89	\$5.12
26	Network Upgrade Charge	\$3,968.07	\$330.67	\$76.31	\$15.26	\$0.95	\$10.87	\$0.45
26a	Multi-Value Projects	-	-	-	-	\$1.63	-	\$1.63
45	Cost Recovery of NERC Recommendation or Essential Action	\$76.89	\$6.39	\$1.47	\$0.30	\$0.02	\$0.21	\$0.01

**Table 8.2-3: PJM Transmission Rates Table**

Schedule	Description	\$/MW-MO	\$/MW-WK	\$/MW-Day	\$/MW-HR
1A	Scheduling, System Control and Dispatch Service	-	-	-	\$0.3763
2	Reactive Supply and Voltage Control Service	-	-	-	\$0.1100
6A	Black Start	-	-	-	\$0.0125
7	Firm Point to Point	\$4,620.90	\$1,063.44	\$151.92	\$6.3300
8	Non Firm Point to Point	\$4,620.90	\$1,063.44	\$151.92	\$6.3300
9-1	Control Area Administration	-	-	-	\$0.2207
9-3	Market Support	-	-	-	\$0.0487
9-FERC	FERC Annual Charge Recovery	-	-	-	\$0.0783
9-OPSI	Organization of PJM States, Inc. Funding	-	-	-	\$0.0010
9-CAPS	Consumer Advocates of PJM States, Inc. Funding	-	-	-	\$0.0006
9-MMU	MMU Funding	-	-	-	\$0.0067
9-PJM	PJM Settlement	-	-	-	\$0.0061
Market Support Offset	Offset	-	-	-	-\$0.0061

Table 8.2-4: TVA Transmission Rates Table

Schedule	Description	\$/MW-MO	\$/MW-WK	On-Peak Rates		Off-Peak Rates	
				\$/MW/Day	\$/MW-HR	\$/MW-Day	\$/MW-HR
1	Scheduling, System Control and Dispatch Service	\$130.00	\$30.10	\$6.02	\$0.38	\$4.30	\$0.18
2	Reactive Supply and Voltage Control from Generation Sources Service	\$375.00	\$86.40	\$17.28	\$1.08	\$12.34	\$0.51
7	Firm Point to Point	\$1,578.00	\$364.20	\$72.84	-	-	-
8	Non Firm Point to Point	\$1,578.00	\$364.20	\$72.84	\$4.55	\$52.03	\$2.17

LGE-KU rates were effective from 6/1/2020 through 5/31/2021

TVA rates effective 11/1/2020

MISO rates effective 2/1/2021 (updated monthly)

PJM rates effective 1/1/2021

Transmission rates vary by provider and are affected year-to-year by revenue requirements for providing transmission service. A historical snapshot for LG&E/KU, MISO, PJM, and TVA can be seen in the figures below.

PJM transmission service rates have recently changed. On June 11, 2019, PJM transmission owners filed proposed revisions to Schedules 7 and 8 for firm and non-firm point-to-point transmission service to the border of PJM. The transmission owners wanted to end the cross-subsidy that zonal NITS customers had been providing to those customers taking point-to-point service at the border. The transmission service rates, which had not changed since 2004, were increased on January 1, 2020. The rates will be updated annually to reflect new transmission investments and new transmission owners. There are still legal proceedings going on surrounding the rates. Although the rates are posted, in the event a ruling lowers the rates retroactively, rebates would be awarded with interest. Figure 8.2-1 through 8.2-4 shows the rate history.

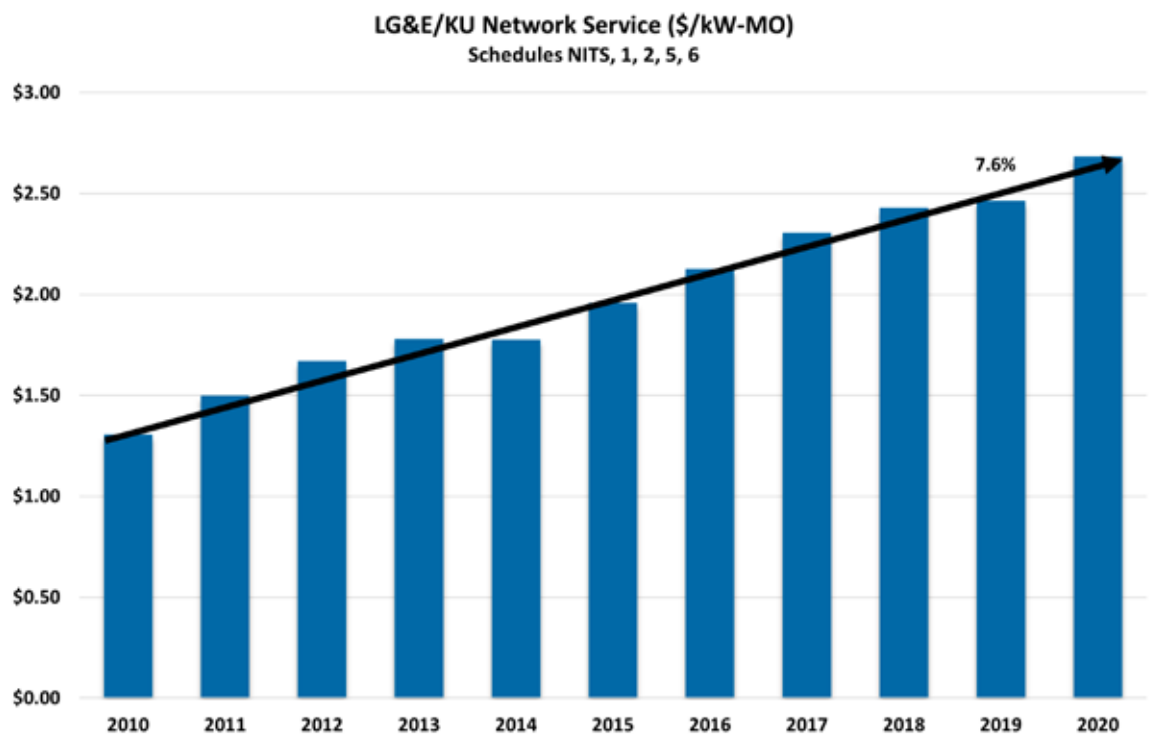


Figure 8.2-1: LG&E/KU Network Service (\$/kW-MO)

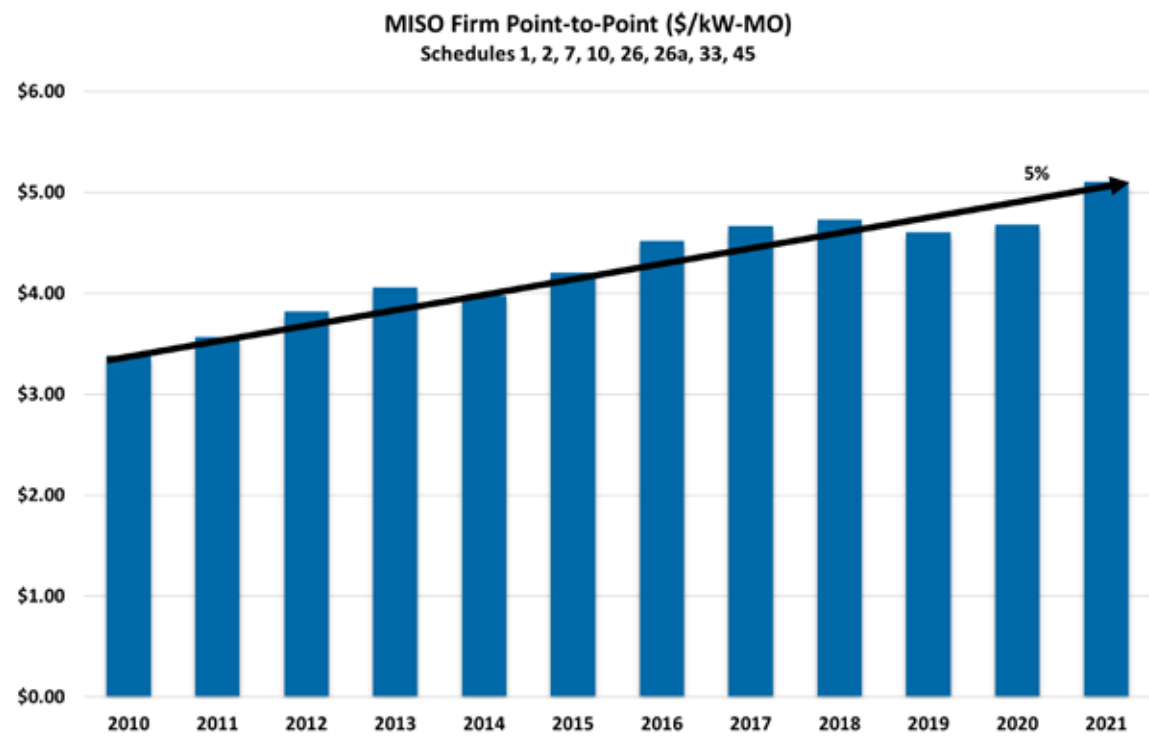


Figure 8.2-2: MISO Firm Point-to-Point (\$/kW-MO)

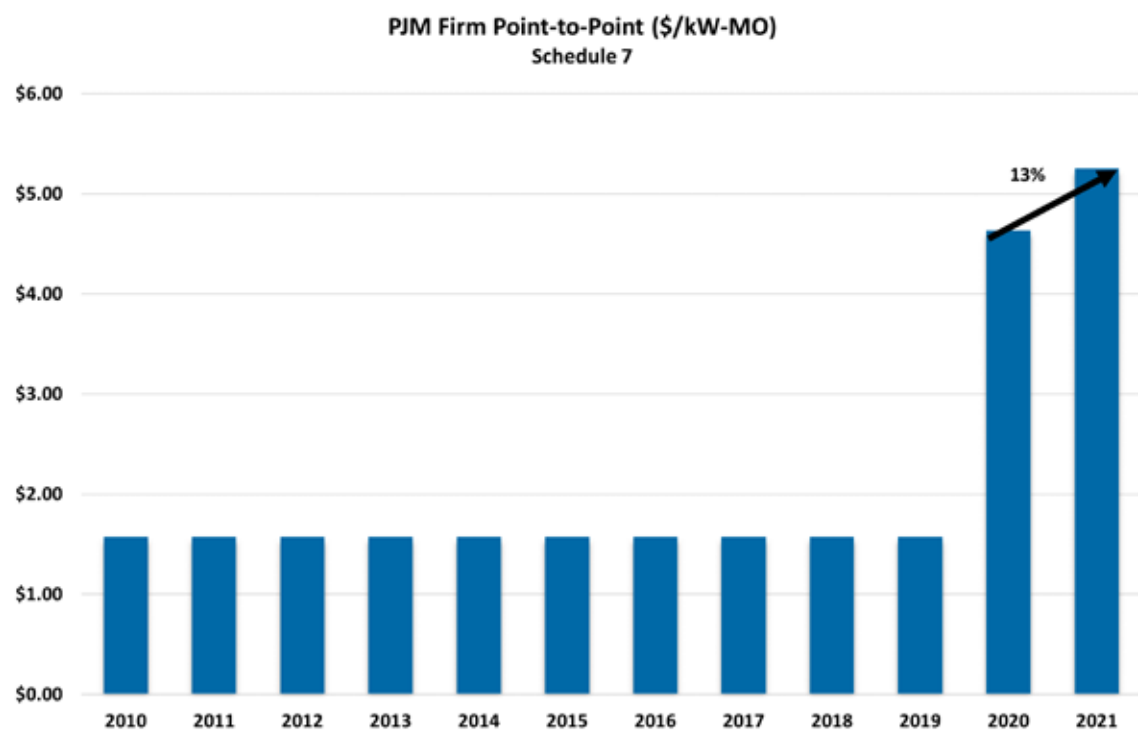


Figure 8.2-3: PJM Firm Point-to-Point (\$/kW-MO)

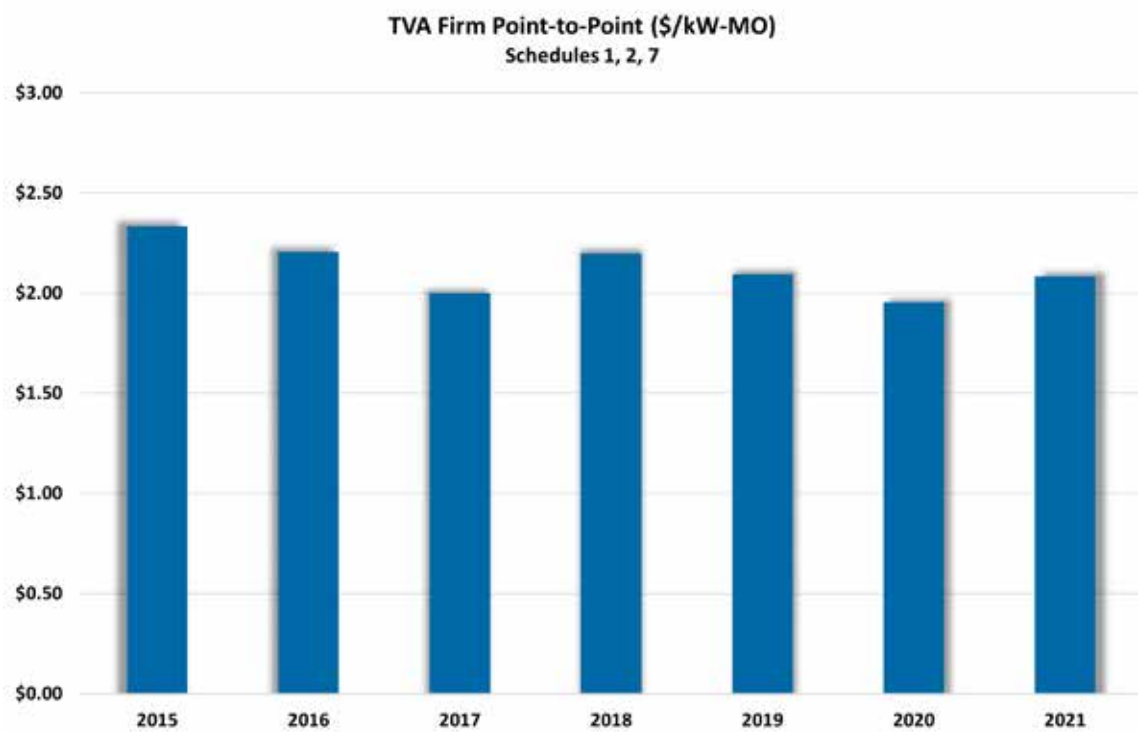


Figure 8.2-4: TVA Firm Point-to-Point (\$/kW-MO)



8.3 Distribution System

Electric power is eventually delivered to the distribution systems of each of KYMEA's members. The delivered energy is metered with revenue-grade meters, and the data undergoes a checkout process with the BA. The actual meters are tested every two years to make sure they stay within compliance levels. KYMEA's members maintain and operate the distribution systems. Those systems include transformers, substations, circuit breakers, relays, and all other related distribution equipment. The members maintain their system voltage and reactive power levels within compliance levels.

Impact of Distributed Energy Resources (DER)

Generally, KYMEA's responsibility for delivering power to the members ends at the substation step down transformer as highlighted in the green area in Figure 8.3-1; however, the KYMEA AR contracts provide for KYMEA to purchase member-owned generation as well as the generation from Public Utility Regulatory Policies Act (PURPA) qualified facilities. Resources owned by member customers would be subject to the member's net metering policy.

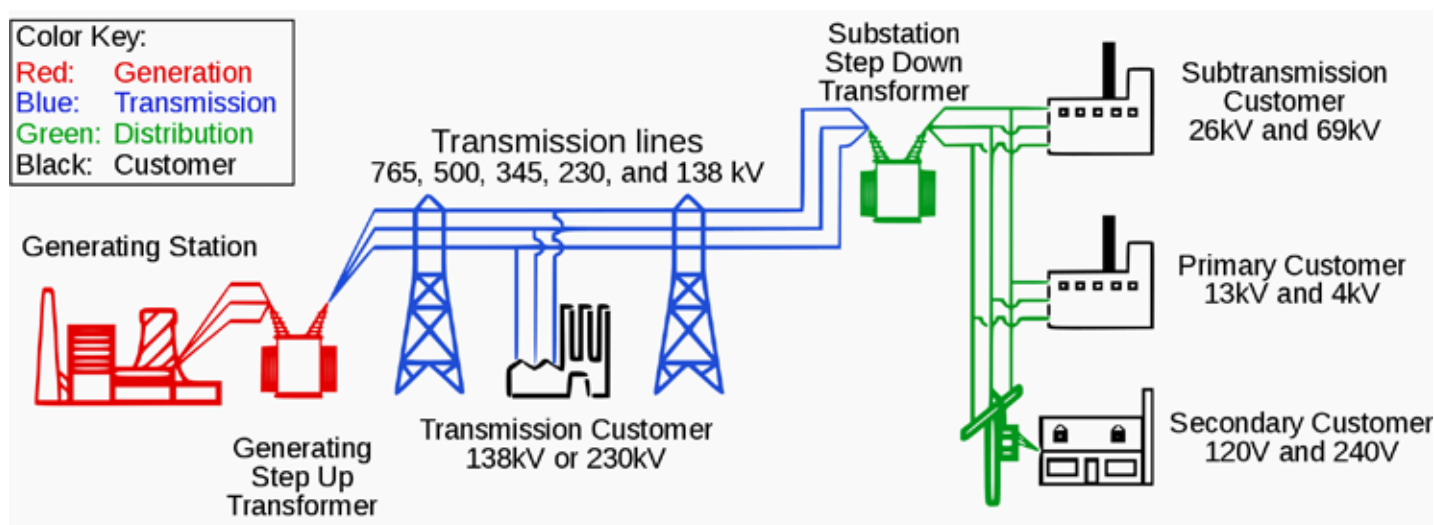
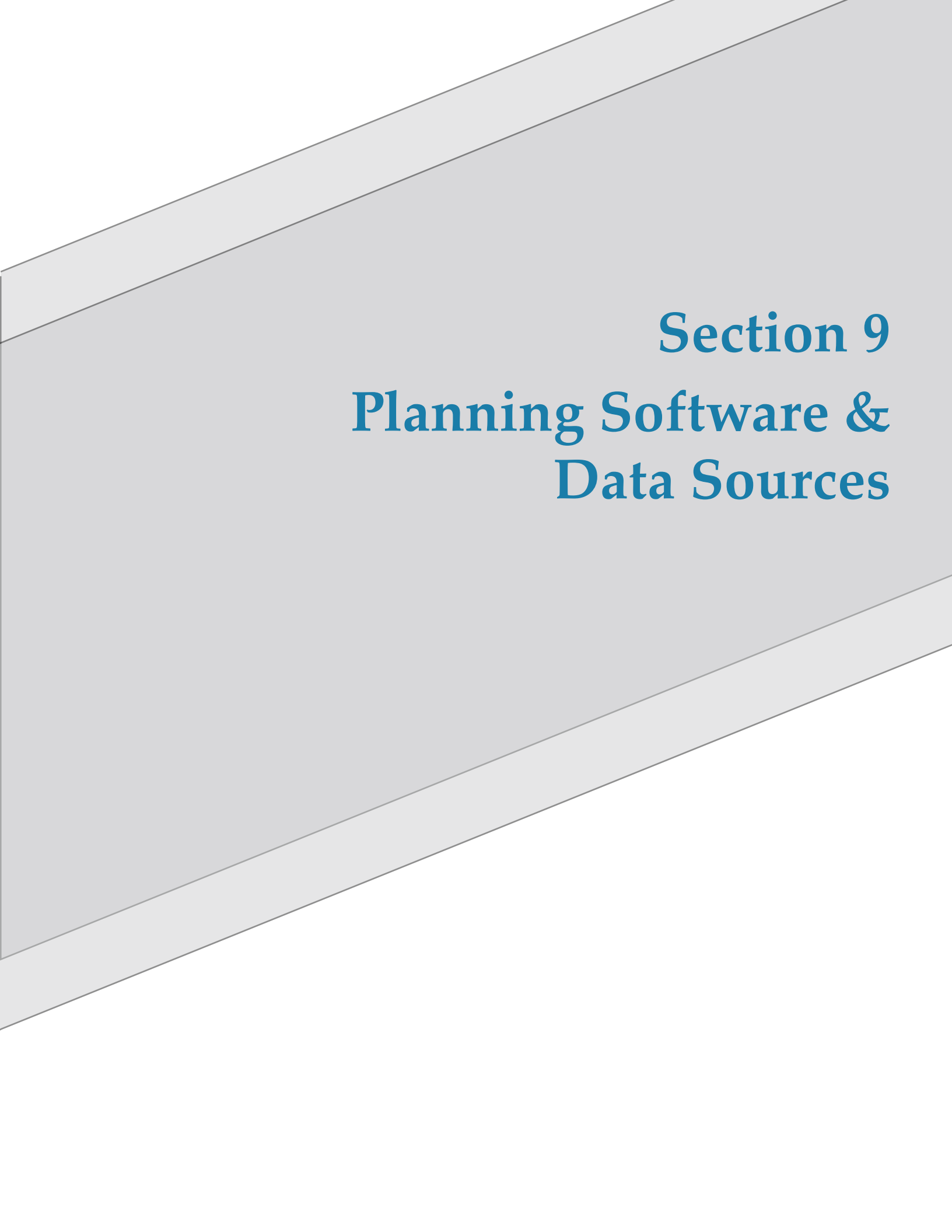


Figure 8.3-1: Electric Power System⁹⁷

97 Csanyi, E., & Electrical Engineering Portal. (2017, October 9). Electric Power System [Digital image]. Retrieved April 26, 2021, from <https://electrical-engineering-portal.com/electric-power-systems>

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Section 9

Planning Software & Data Sources

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9. PLANNING SOFTWARE & DATA SOURCES

9.1 Power Planning Software

KYMEA utilizes the EnCompass Power Planning Software (“EnCompass”) from Anchor Power Solutions to perform its market price forecasting, resource planning, and portfolio simulations.

The strength of EnCompass is its ability to mimic and forecast the behavior of the power markets. Many RTO electricity markets, for example MISO and PJM, co-optimize production and pricing of ancillary services such as spinning reserve, operating reserve, and regulation with that of energy. Co-optimization has proven benefits in reducing ancillary service costs and in providing consistent pricing incentives for potential providers of both energy and ancillary services.

The EnCompass model simulates the RTO market dynamics by optimizing across the energy and ancillary services markets while simultaneously optimizing the capital requirements, costs, and physical constraints of environmental policies, such as carbon emission limits and renewable portfolio standards.

EnCompass uses mixed integer programming to solve complex problems while observing the binding integer constraints. For the integer variables (units online, project additions, outage days), a problem is first solved without forcing the integers to be whole numbers. Then, an algorithm is used to search for the best way to round up or down any fractional values. The search stops when the best solution found is within an input tolerance of the best theoretical solution (known as the best bound).

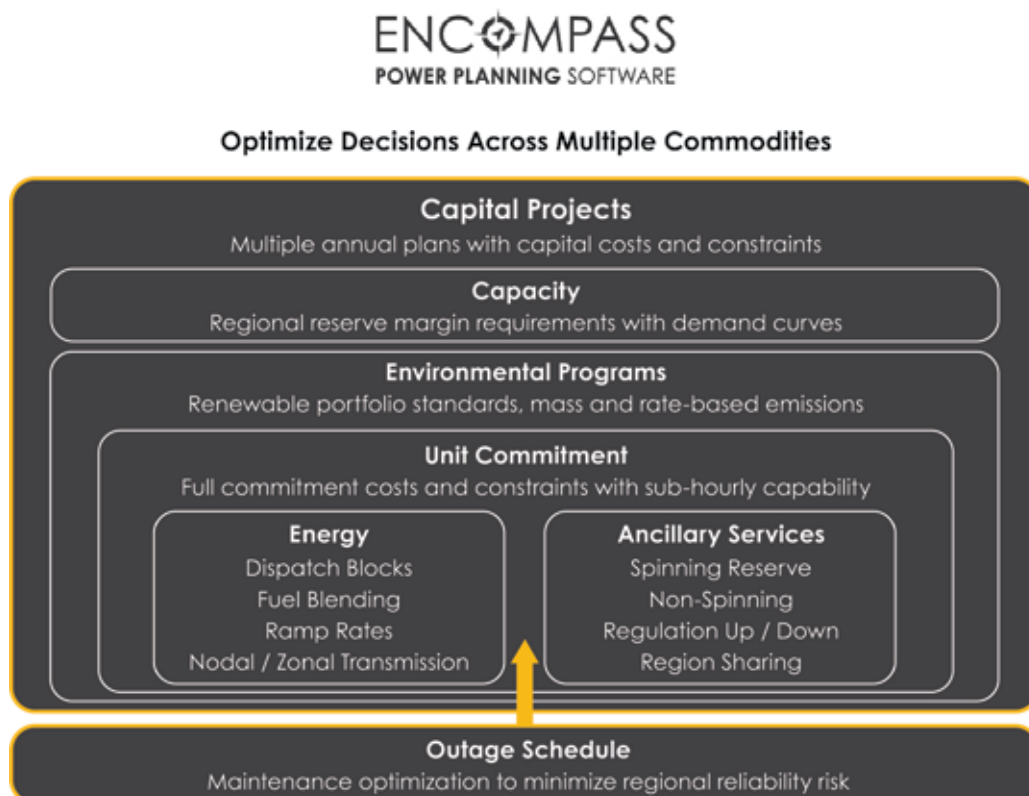


Figure 9.1-1: EnCompass Optimize Decisions Across Multiple Commodities⁹⁸

98 Anchor Power Solutions. (n.d.). EnCompass power planning software. Retrieved April 22, 2021, from <https://anchor-power.com/encompass-power-planning-software/>



9.2 Encompass Simulations

EnCompass Resource Planning

EnCompass produces least-cost portfolios of resources to meet future needs, subject to resource operating parameters, planning reserves, and environmental programs. The model's objective function is to minimize the sum of all costs included in the optimization. For environmental programs such as a carbon limit, the model creates a shadow cost. A shadow cost is an estimated cost for something that is not normally priced or sold in the market. For North American power market simulations, the model economically retires unprofitable units. Modeling retirements is particularly important as the industry continues to experience a flurry of coal-based and nuclear retirements due to unfavorable market conditions, environmental policies, and market rules.

Encompass Market Simulation

Since the arrival of the RTO, the future cost of market power and energy is one of the most critical aspects of utility planning. No longer can utilities simply plan as island entities, building for their own load in a vacuum. Planning must incorporate a reasonable and realistic forward view of the market. To simulate the North American power markets in their entirety, KYMEA utilizes the EnCompass market price forecasting capability with the EnCompass-Ready National Database ("NDB") from Horizons Energy.

EnCompass forecasts annual capacity prices using the same type of methodology used in MISO and PJM, including vertical or downward-sloping demand curves. New capital projects and resources eligible for retirement will submit capacity bids to recover fixed operating and capital carrying costs, less any profits from the energy and ancillary service markets. If there are still unrecoverable costs, EnCompass will dynamically adjust energy and ancillary service bids using an operating reserve demand curve (ORDC) to match the RTO market rules.

Encompass Portfolio Simulation

The input drivers and resulting market prices derived from the market simulations become inputs for the KYMEA portfolio simulations. Care is taken to ensure the time series sequence of hourly loads, renewable energy patterns, and resulting market prices from the North American power market simulations are preserved in the portfolio model simulations. As the nation's resource mix shifts towards renewable and energy storage resources, maintaining the hourly system operation between market and portfolio simulations reflects the time-of-day impact between dispatchable thermal generation that can be brought online as needed to match energy demand and generation from renewable and storage resources which are subject to availability limitations. EnCompass simulates the hourly operations—and the associated cost of serving KYMEA's loads—of each portfolio across the full planning horizon, capturing detailed unit commitment dynamics, dispatch constraints, and transmission limitations.

Horizons National Database

The NDB is a complete EnCompass database for North American power markets. With the database, EnCompass is used to forecast 30-year prices for energy, ancillary services, capacity, emission allowances, and renewable energy. Other market metrics can be produced, including hourly generator operations, transmission flows, and congestion costs.

As a market participant in both the MISO and PJM, KYMEA is interested in forward energy and capacity price curves for two specific market zones (MISO Indy.Hub and PJM AD.Hub). To capture the market impact of both regional capacity/energy mixes as well as national policies such as a carbon cap, the entire North American footprint is modeled as 78 zonal markets as shown in Figure 9.2-1.

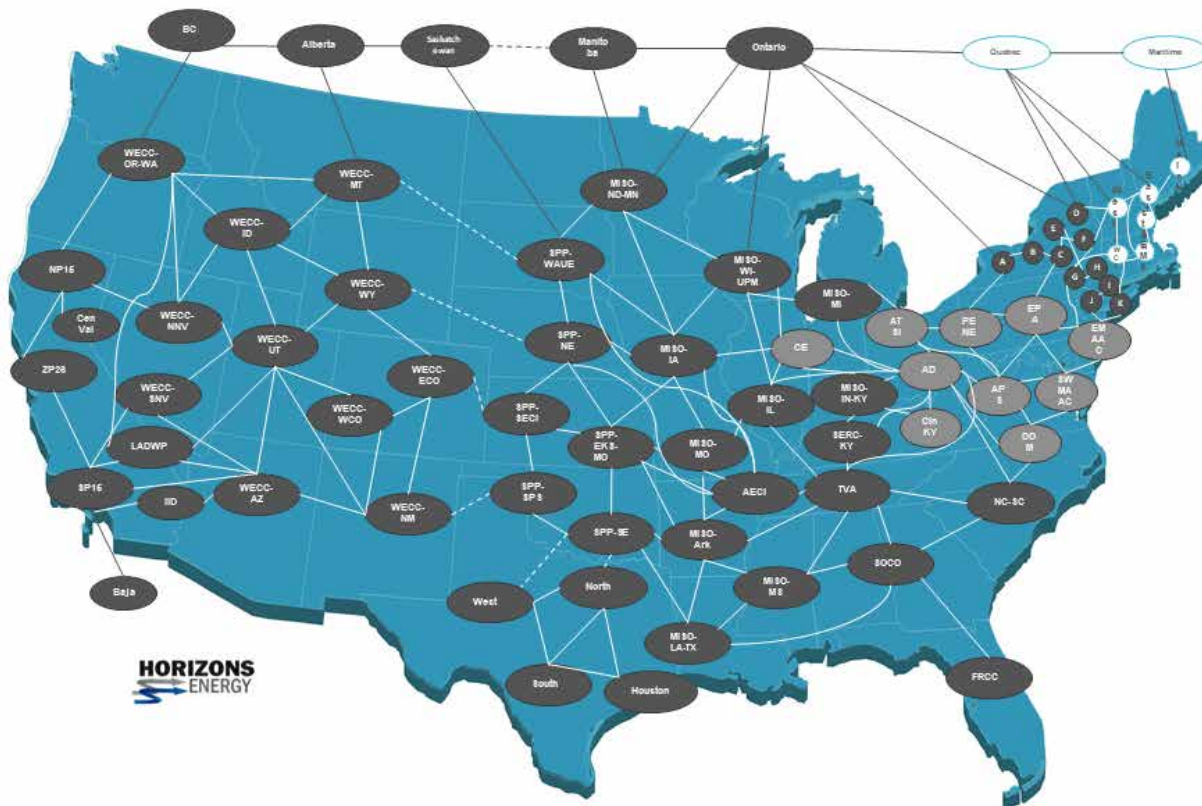


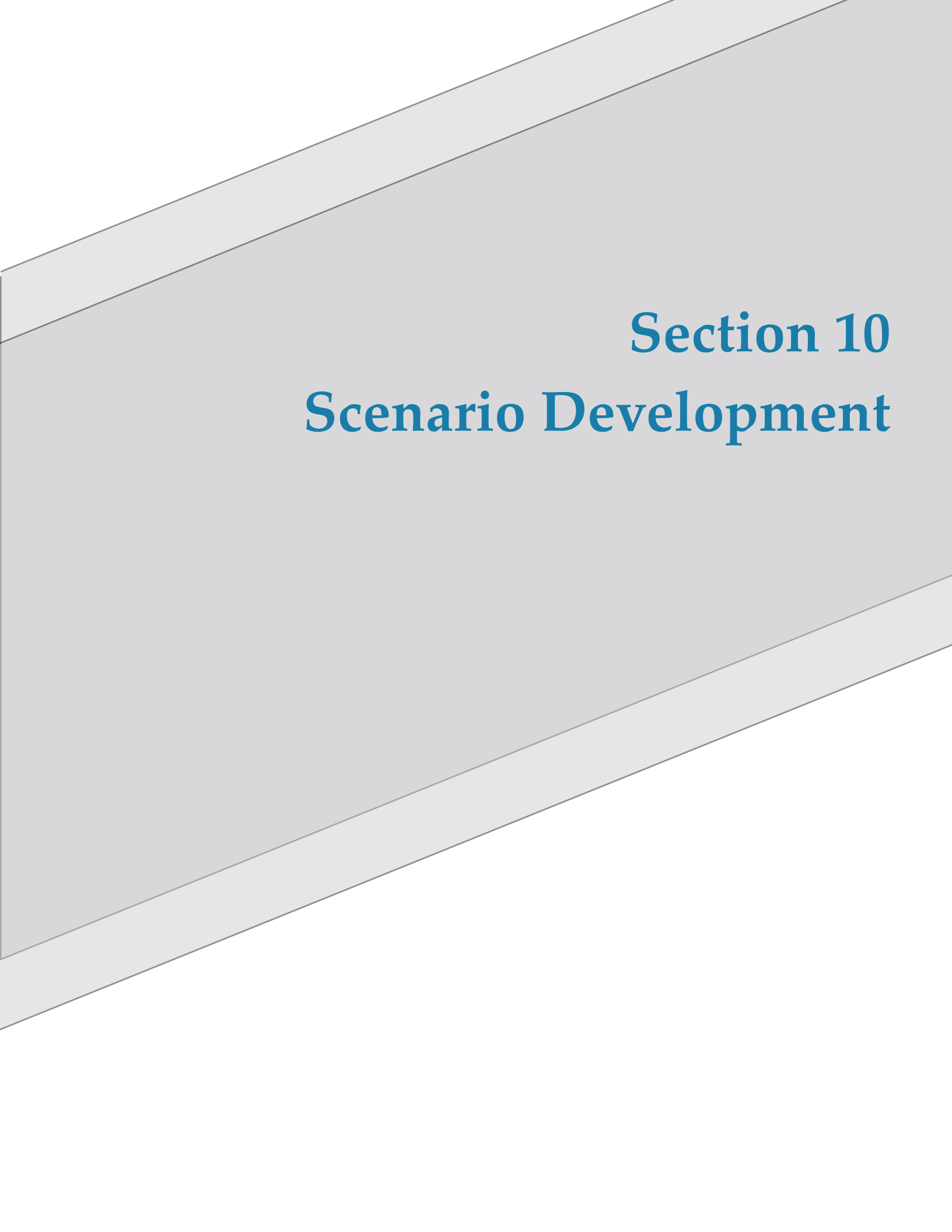
Figure 9.2-1: Horizons Energy National Database Topology⁹⁹

99 Horizons Energy. (2020, January 08). EnCompass ready data. Retrieved April 22, 2021, from <https://www.horizons-energy.com/advisory-services/advisory-service-2/>



9.3 External Data Sources

KYMEA’s database uses a mix of publicly available forecasted information and KYMEA proprietary information from a variety of sources. The sources have been compiled into a table in Section 18.



Section 10

Scenario Development

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10. SCENARIO DEVELOPMENT

KYMEA utilizes scenarios as a structured way to think about the future as scenario planning is a proven tool to better anticipate and respond to future risks and opportunities. For IRP2020, KYMEA partnered with Horizons Energy to utilize nine distinct scenarios from Horizons Energy Spring 2020 Report and planning services. KYMEA also worked with Horizons Energy to develop stories about how the future might unfold by iteratively building plausible alternate views of the future given different economic, regulatory, and technological driving forces.

Scenarios were developed using combinations of key drivers, which were polished to ensure each scenario:

- Represented a plausible, meaningful future in which KYMEA could envision itself operating within
- Was unique among the various scenarios being studied
- Placed adequate stress on resource selection and provided a foundation for analyzing the strength, flexibility, and adaptability of each combination option; and
- Captured relevant key stakeholder interests

The scenarios were grouped into carbon and no carbon emission limit groups. They are reflective of economic growth and decline, emerging technologies, stringent environmental regulations, and changing paradigms. KYMEA selected the nine unique scenarios summarized in Figure 10.1-1.



KYMEA SCENARIO ROADMAP

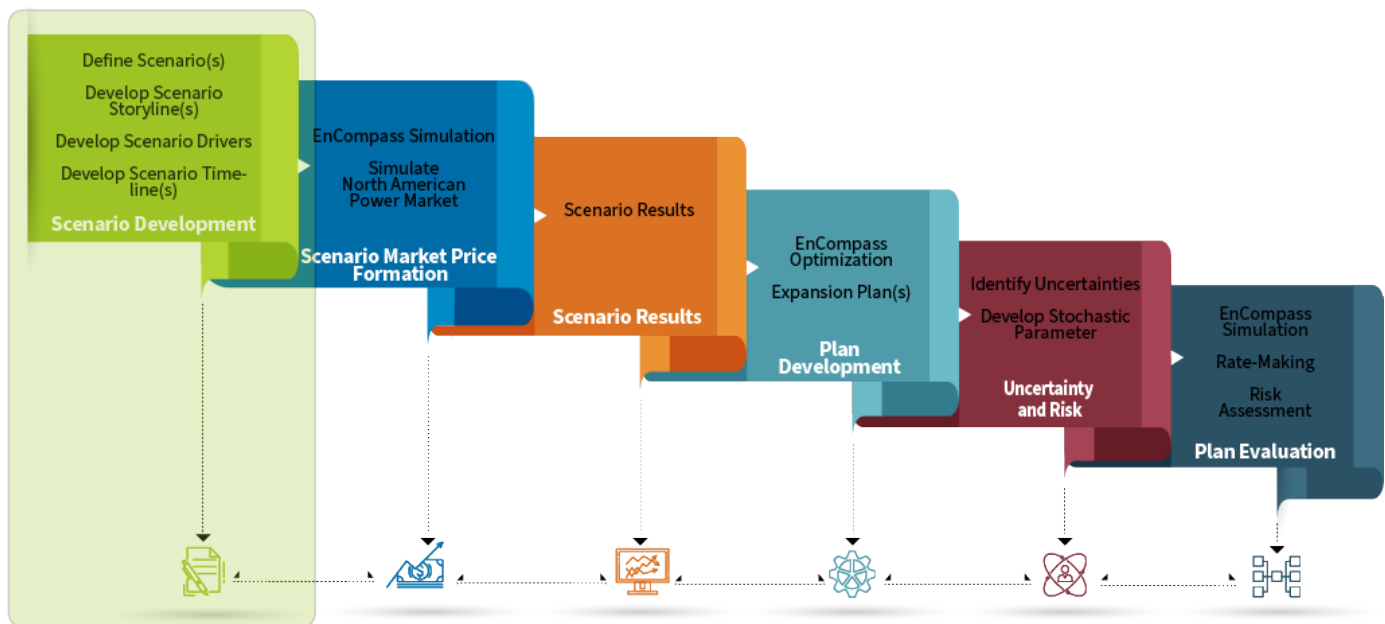
Figure 10.1-1: KYMEA Scenario Roadmap



The scenario development process acknowledges that business environments of both today and tomorrow are increasingly complex and unpredictable. A key aspect of scenario planning for an electric utility is the transformation of the scenario narrative into electricity market characteristics that can be incorporated into the IRP process. This is a complicated task that involves detailed modeling of electricity markets under the scenario's conditions—essentially a NERC-wide IRP for each scenario.

Shown below is a flowchart detailing the IRP process. The goal of defining and developing scenarios is the creation of alternate futures that result in different resource mixes. Ideally, the scenarios serve as “bookends” that examine a variety of high consequence outcomes.

IRP FLOWCHART



10.1 Scenario Themes

For the IRP2020, KYMEA identified nine distinct themes from Horizons Energy which are expected to have the greatest impact on the future energy business environment over the next 20 years. KYMEA looks for signposts that signal the scenario may occur, providing an early warning system of possible events to follow. The more credible the signpost identified for any given scenario, the greater the likelihood that the scenario and its associated strategic implications will be relevant. While possible carbon regulations are a major factor of each theme - demand, fuel prices, technology, resources, reserve margins, etc., all play a role in the development of the scenario.



10.1.1 Status Quo Storyline

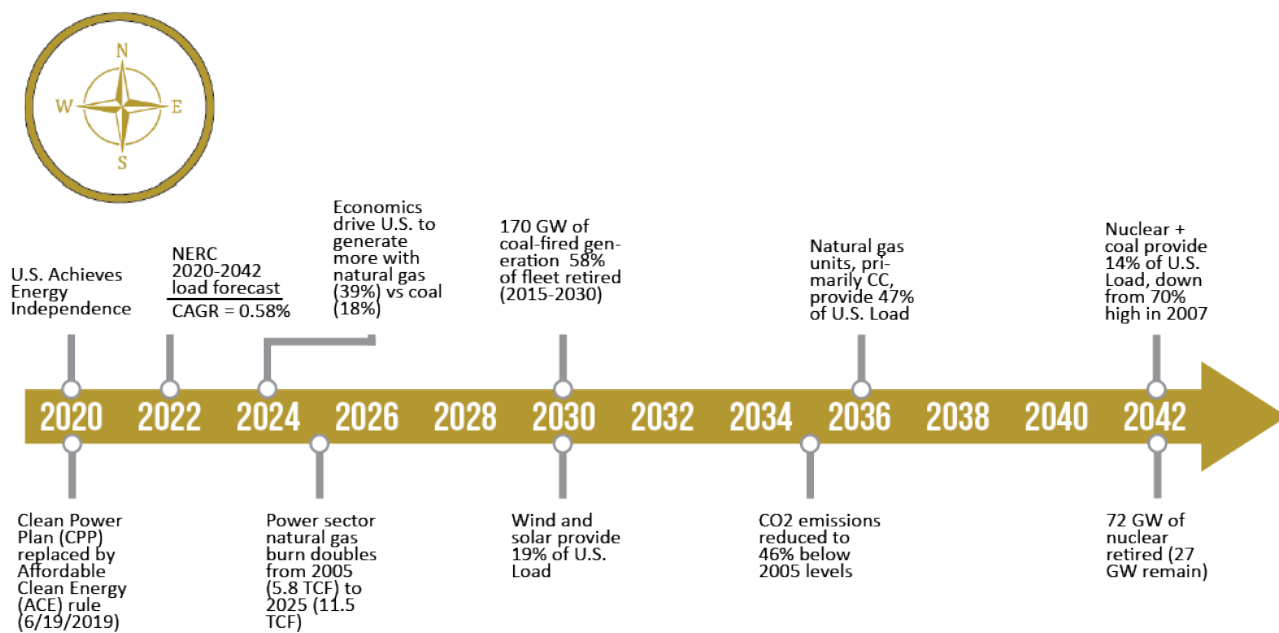


Figure 10.1.1-1: Status Quo Timeline

The Status Quo scenario or Base Case includes only known events and expected trends (e.g., forecasts of fuel prices, economic forecasts, estimated future capital costs, expected load forecast, etc.). This scenario provides a 22-year projection without any unduly speculative and significant changes to resources or laws/policies affecting resources that are not known and measurable.

Energy Emissions Regulations

The Trump administration replaced the CPP with the ACE rule, which is less restrictive. The ACE rule would have lowered power sector emissions by 11 million tons by 2030, or between 0.7% and 1.5%. On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit struck down the Trump administration's ACE rule, citing that it failed to provide adequate environmental and health protections. This decision will provide a path forward for the new administration's clean energy plan.

Kentucky, long known to be a heavy coal state, had approximately 11 GW of operational coal in 2020. This is a reduction from all-time high installations of 15 GW. An additional 2 GW are slated for retirement in the next ten years. In 2019, coal-fired power plants supplied 73% of Kentucky's electricity generation compared to historical production of more than 90% of Kentucky's net generation. As older coal-fired generating units became more costly to operate, a number of coal-fired power plants in Kentucky were recently retired or retrofitted to burn natural gas. These changes to Kentucky's energy landscape occurred absent of carbon regulations.



Energy Independence Pushes Focus on Tapping North American Resources

Energy production hit a record high in 2018 as production grew by 5.7%, while energy consumption decreased by 0.9%. The significant growth can be attributed to an increase in crude oil and natural gas production from hydraulic fracturing and horizontal drilling. This notable production growth has also contributed to the U.S.'s remarkable achievement of energy independence for the first time in 62 years.

Figure 10.1.1-2 shows that in 2019, energy production exceeded energy consumption in the United States on an annual basis for the first time since 1957, according to the EIA's Monthly Energy Review. Production in the United States reached 101.0 quadrillion British thermal units (quads) of energy versus a consumption of 100.2 quads in 2019.

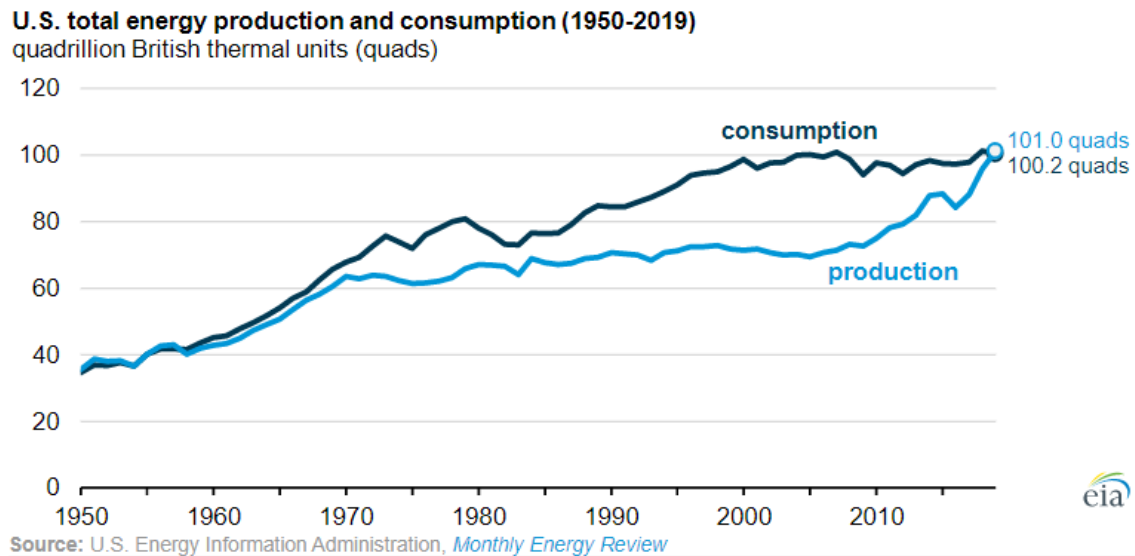


Figure 10.1.1-2: U.S. Total Energy Production & Consumption Graph



Figure 10.1.1-3 shows the natural gas price staying low; but gradually increasing over time.

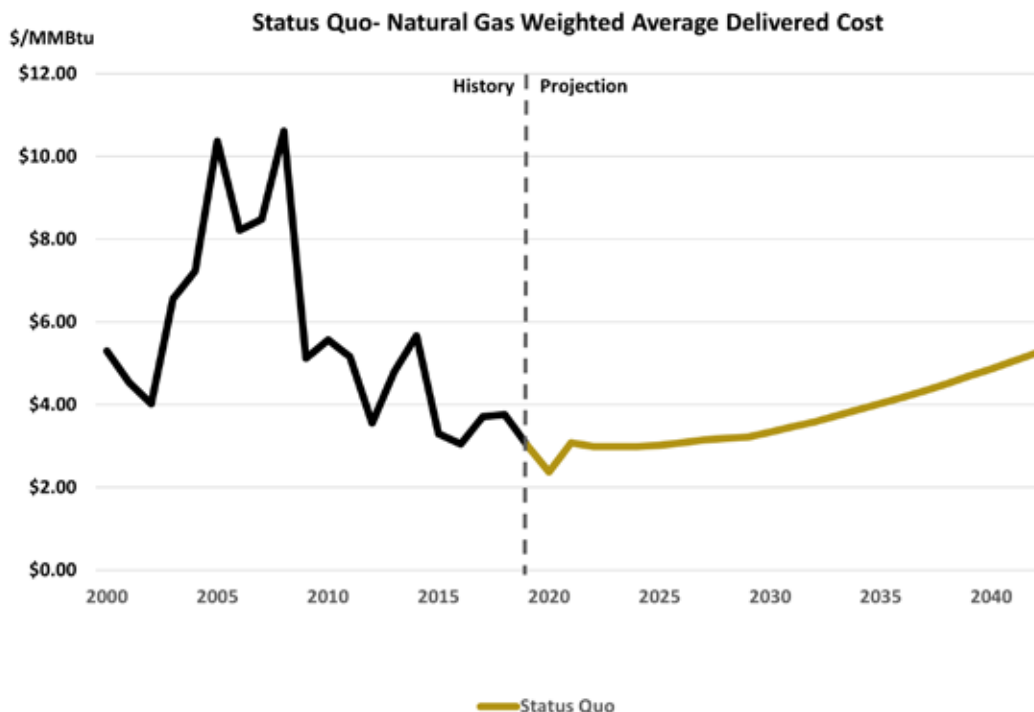


Figure 10.1.1-3: Status Quo Scenario Natural Gas Price Graph

Economic Drivers Push Continued Fossil Fuel Retirements

To forecast unit retirements, Status Quo considers announced retirements as known and measurable. All scenarios assume the ability to economically retire unprofitable units. By the end of the study, 3 GW of coal were economically retired in Kentucky. It is assumed that wind resources built before 2021 receive production tax credits (PTCs), and solar resources will receive declining levels of ITCs to a floor of 10%. Energy efficiency is added economically in the states with an energy efficiency resource standard (EERS). Behind-the-meter generation is also added consistent with assumptions in the 2020 EIA Annual Energy Outlook (AEO). These assumptions result in a compound annual growth rate (CAGR) of 0.1% in energy and 0.2% in demand for the market area of MISO-IN-KY or MISO Load Zone 6. Status Quo also reflects over 3 GW of behind-the-meter (BTM) rooftop solar by 2050.

Figures 10.1.1-4 and 10.1.1-5 provide the North American projected peak demand and energy for the Status Quo scenario.

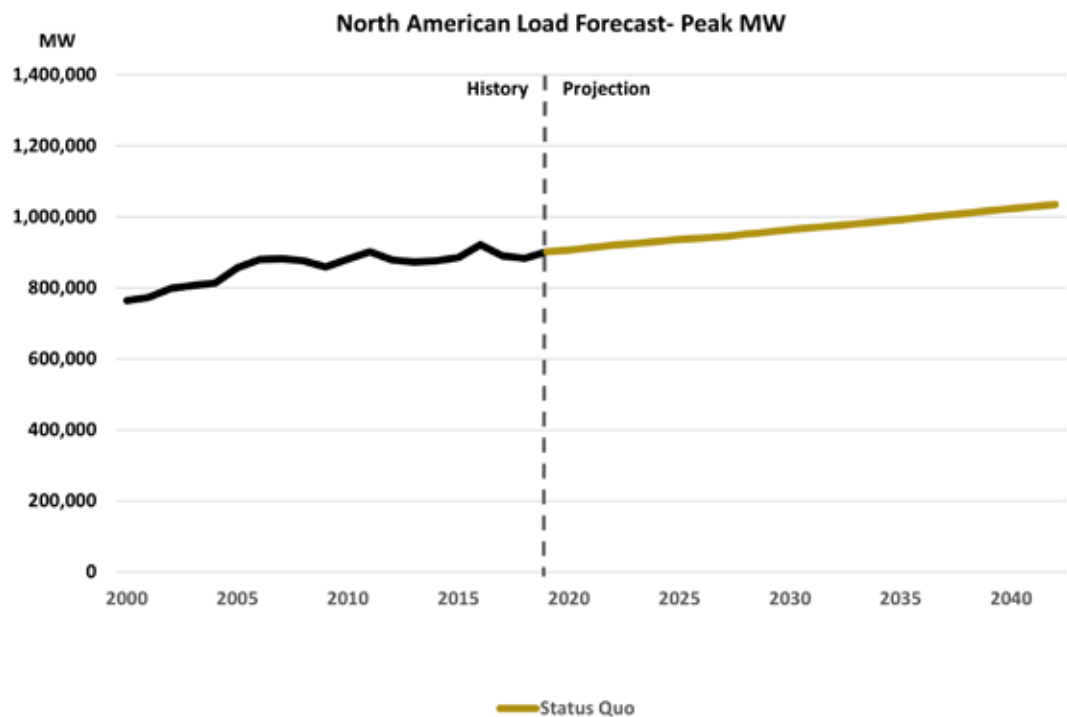


Figure 10.1.1-4: Status Quo Scenario North American Load Forecast Graph - Peak

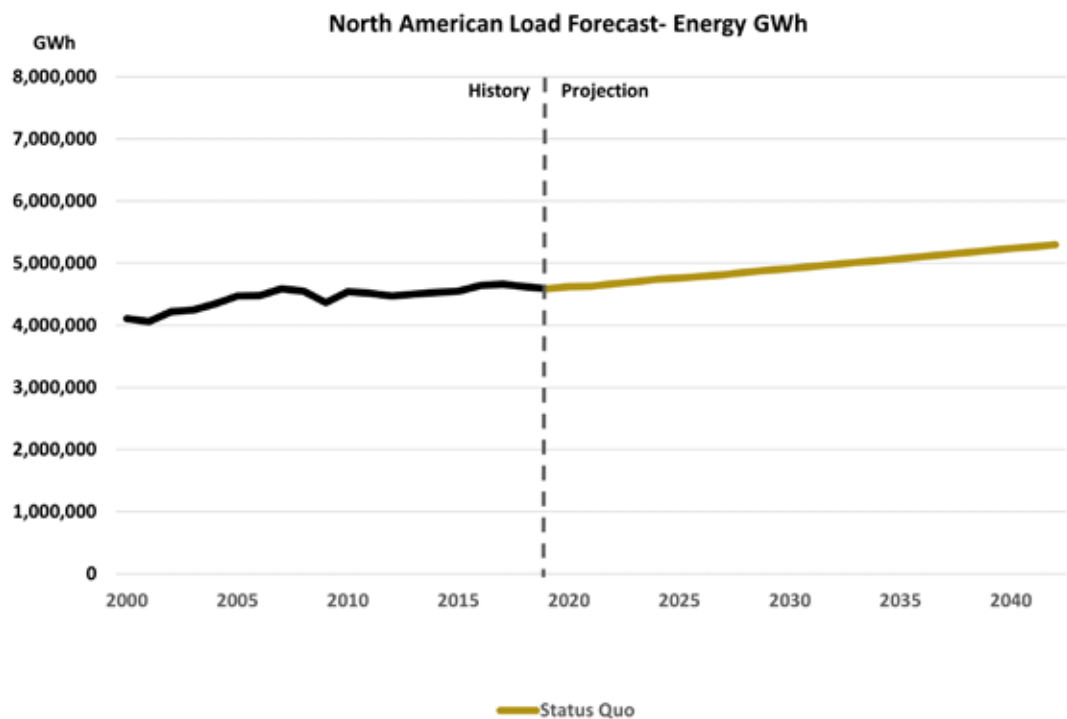


Figure 10.1.1-5: Status Quo Scenario North American Load Forecast Graph - Energy



10.1.2 High Natural Gas Storyline

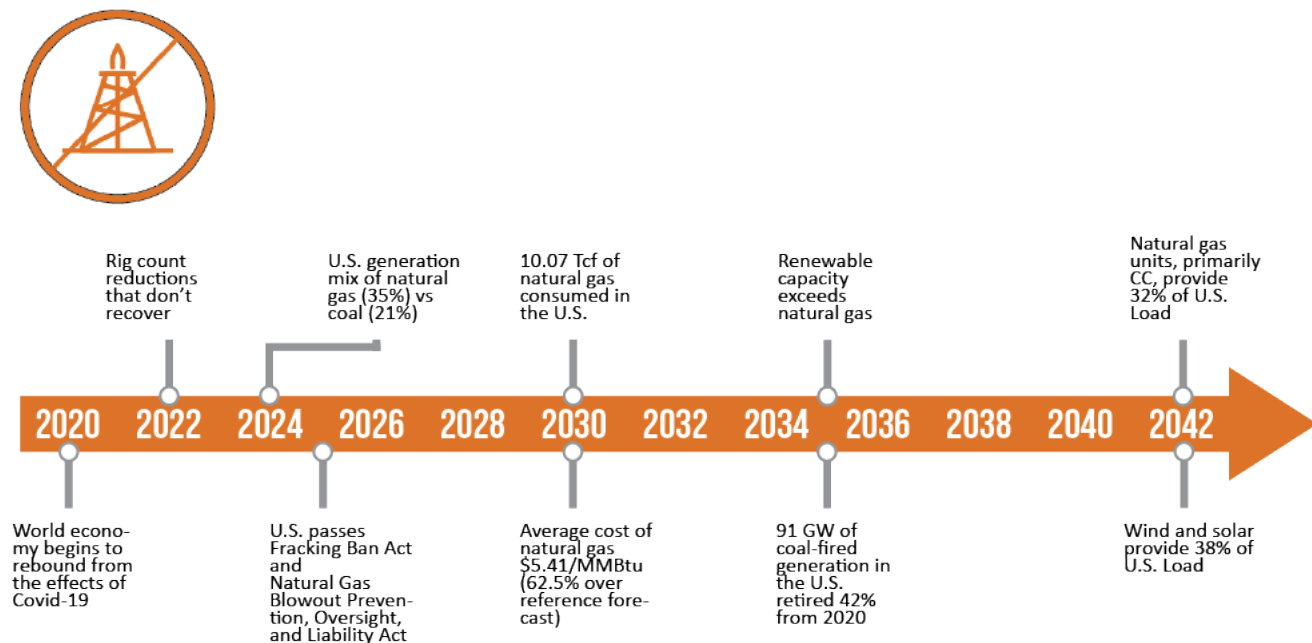


Figure 10.1.2-1: High Natural Gas Timeline

Supply-Side Factors Affect Natural Gas Prices

Estimates of technically recoverable shale oil and natural gas resources are uncertain and change over time as new information is gained through drilling, production, and technology experimentation. During the past decade, as more shale oil formations have gone into production, estimates of technically recoverable tight/shale oil and natural gas resources have generally increased. However, these increases in technically recoverable resources (TRR) are based on many assumptions that might not apply over the long term or over the entire tight/shale formation. Currently, production is so heavy that producers are routinely flaring.

Three major supply-side factors affect prices:

- Amount of natural gas production
- Level of natural gas in storage
- Volumes of natural gas imports and exports



High Production Costs Promote Low Storage Levels

The High Natural Gas scenario is intended to address the uncertainty around natural gas production costs and storage levels. The estimated ultimate recovery per well is assumed to be 50% lower than Status Quo for:

- Tight oil
- Tight gas
- Shale gas in the United States
- Undiscovered resources in Alaska
- Offshore Lower 48 states

Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% lower than Status Quo. Growing demand in domestic and export markets leads to increasing natural gas prices despite continued technological advances that support increased production. Natural gas production expands into less prolific and more expensive-to-produce areas, putting upward pressure on production costs.

High Natural Gas Signposts

The 2020 pandemic created many economic unknowns. The world economy, including the energy industry, is expected to begin its rebound from the effects of COVID-19. After a 4% drop in demand in 2020, recovery is expected in 2021, with forecasts projecting a rebound of 1.5% per year through 2025. However, it is expected that rig counts will be reduced as some will not experience recovery.

One significant signpost for High Natural Gas prices is historical volatility. As shown in Figure 10.1.2-2, the High Natural Gas price is consistent with pricing that was experienced in the 2005 through 2008 time frame when natural gas prices were being influenced by high demand in a pre-shale discovery era.

Another influence on the utilization of shale is the use of hydraulic fracturing to extract natural gas from the formations. Senator Bernie Sanders and Representative Alexandria Ocasio-Cortez, along with the 116th Congress, have introduced legislation that would ban the practice of hydraulic fracturing for oil and natural gas on all onshore and offshore land in the United States. The Fracking Ban Act was introduced in both the House and Senate in early 2020. If passed, the legislation would commence on January 1, 2025. Numerous states are also introducing state-specific legislation to tamp down on the use of fracturing due to water contamination issues. As drilling for natural gas has increased through hydraulic fracturing, it has attracted much public scrutiny. The scrutiny has generated both support and criticism from various stakeholders and ensured the topic will be a reoccurring political debate across party lines in all foreseeable elections.

With the focus on the affects of climate change increasing, methane emissions are also being addressed at some levels. Senator Edward Markey, in August of 2020, introduced the Natural Gas Blowout Prevention, Oversight, and Liability Act, legislation that would regulate large-scale emissions of natural gas—both flared and un-combusted, and its central component, methane. While oil well operators are held liable for oil spills, there are no federal restrictions or liability for large-scale natural gas releases or blowouts. Several states, including Pennsylvania, are also attempting environmental measures to reduce methane emissions.



Figure 10.1.2-2 illustrates the projected high natural gas price compared to the Status Quo scenario

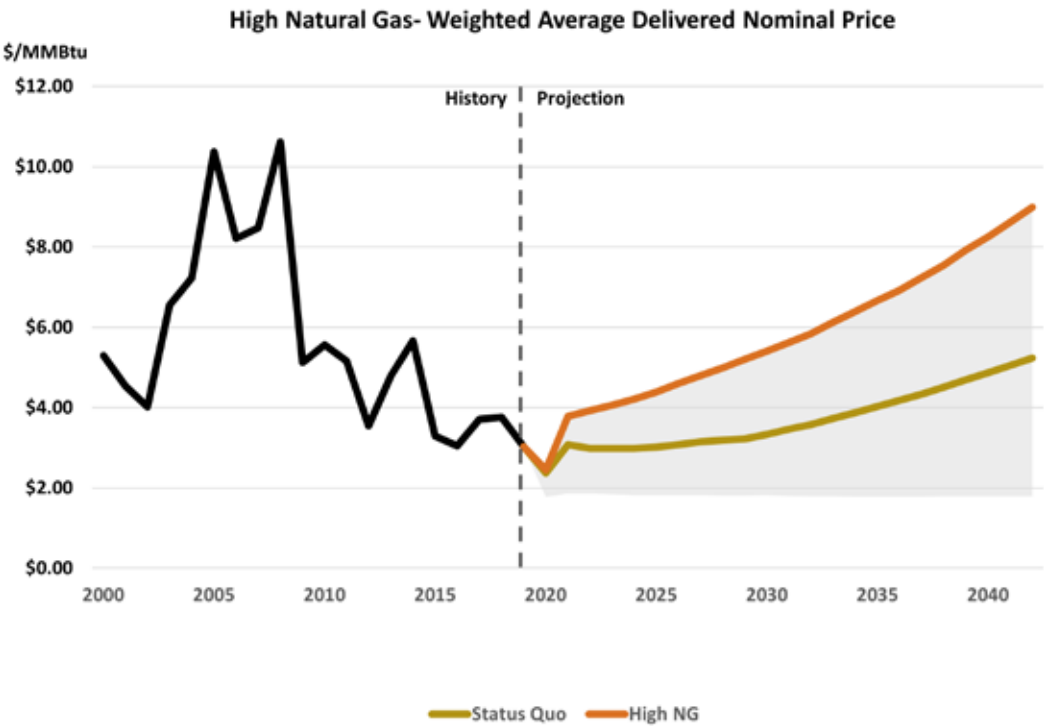


Figure 10.1.2-2: High Natural Gas - Weighted Average Delivered Cost



10.1.3 Low Natural Gas Storyline

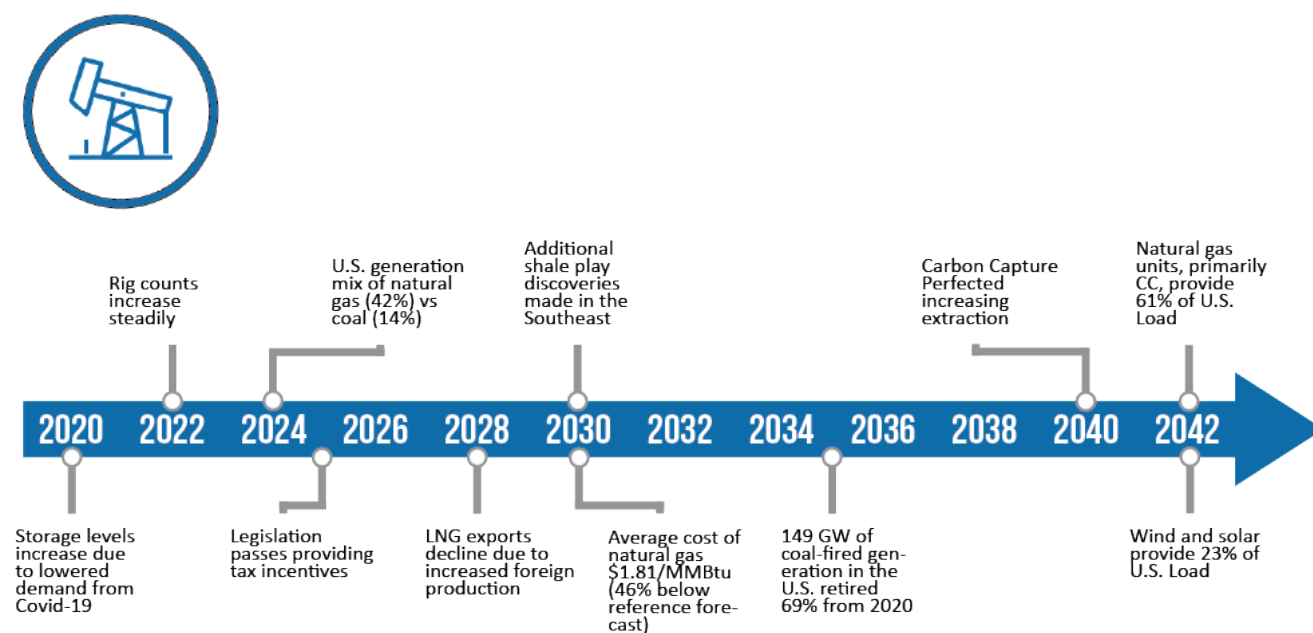


Figure 10.1.3-1: Low Natural Gas Timeline

As discussed previously, there is a great deal of uncertainty associated with the volatility of natural gas pricing. The Low Natural Gas scenario is consistent with the all-time low forward pricing of Henry Hub that has been experienced in the 2019 and 2020 time frame. These low prices have been driven by high storage levels, low production costs, and reduced demand both in the electric residential and commercial sectors. As further evidence, the Low Natural Gas scenario is consistent with the 90th percentile confidence interval level when reviewing Henry Hub pricing back to 2015 and is assumed to remain at those levels throughout the forecast.

High Storage Levels are Linked to a Reduction in Demand

Due to COVID-19, the U.S. has seen natural gas (dry and associated) production diminished in recent months from the nearly 7 billion cubic feet per day (bcf/d). Healthy hedge books are mitigating these production declines. Producers locked in higher prices and made more economical cuts to production, resulting in total U.S. shale gas production down just 1.4 bcf/d year over year in July of 2020, forcing average Henry Hub prices to 25-year lows.

Low Production Costs

An abundance of lower cost resources, primarily in tight oil plays in the Permian Basin, allow these lower cost resources to produce at higher levels with higher recovery rates to lower prices. As reported in the EIA's AEO, the U.S. has seen dry natural gas production from oil formations almost double from 2013 to 2018. This level of production is expected to continue at this rate through 2050. As natural gas prices go down, this will naturally improve the economics of gas generation.



Low Natural Gas Signposts

September 2020's Henry Hub natural gas spot prices were down to an average of \$1.92 per million British thermal units (MMBtu), from August 2020 prices of \$2.30/MMBtu. These declining natural gas spot prices are reflective of a reduction in demand for natural gas as a result of cooler-than-normal temperatures during the second half of September 2020 and a decrease in demand for U.S. liquefied natural gas (LNG) exports due to continued hurricane-related activity in the Gulf of Mexico.

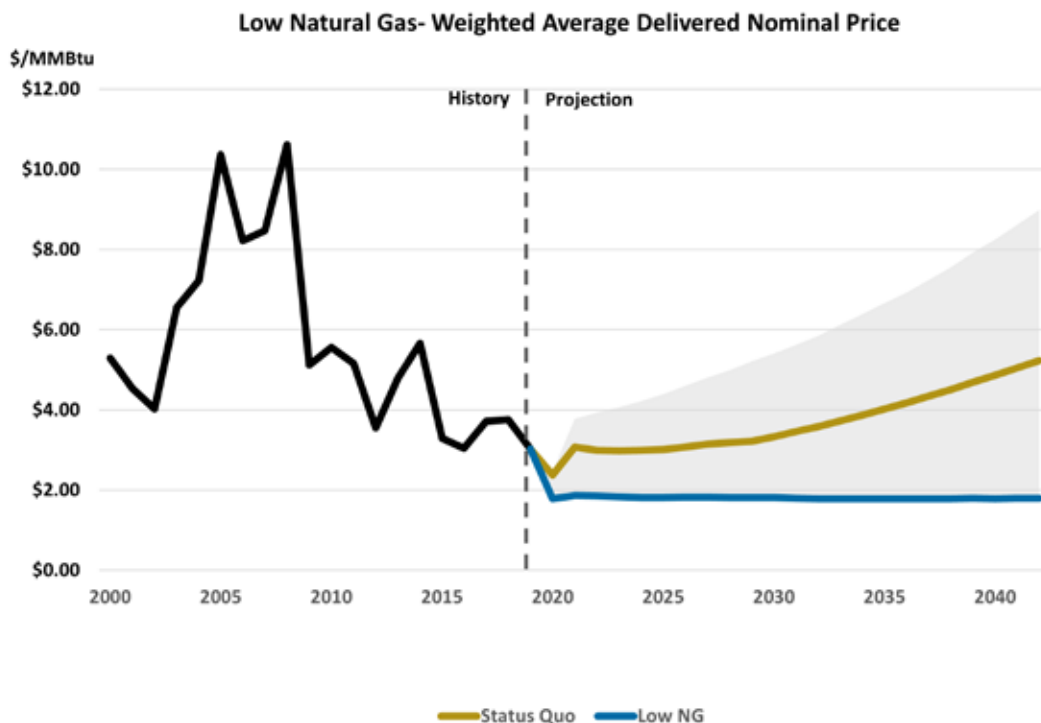


Figure 10.1.3-2: Low Natural Gas - Weighted Average Delivered Costs

Figure 10.1.3-2 displays the pricing information from the 95th percentile using historical prices from 2015 and NYMEX futures as of March 2020.

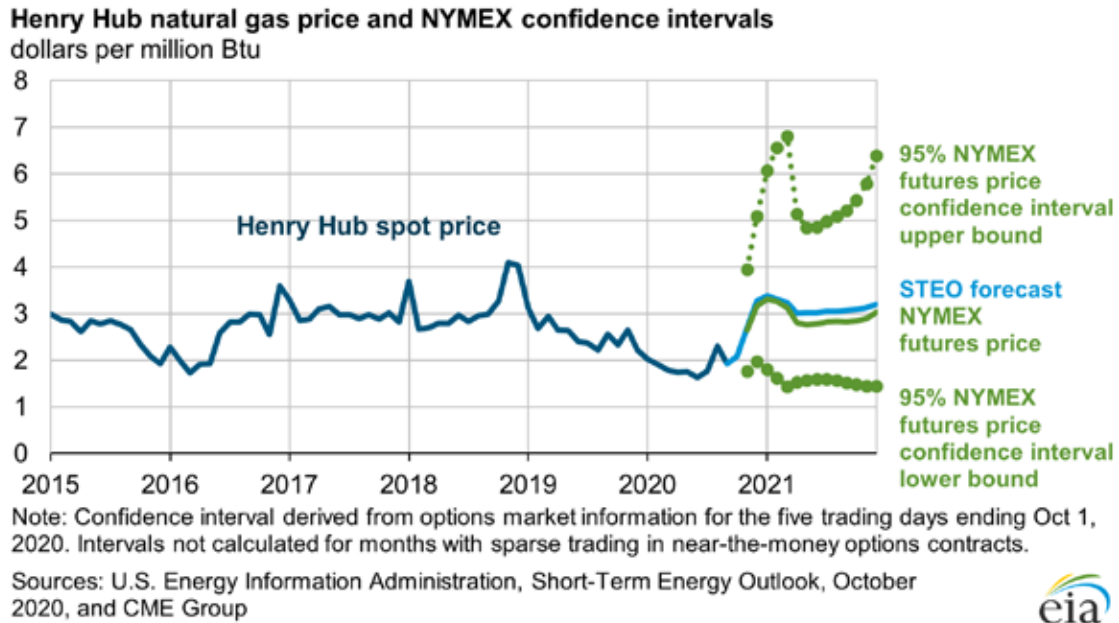


Figure 10.1.3-3: EIA Confidence Interval of Henry Hub¹⁰⁰

Several states have tax incentives in the works for natural gas production. This is consistent with the need for economic recovery. The Pennsylvania House and Senate recently approved HB732 granting tax incentives to natural gas producers that stimulate job growth.

Although international demand for natural gas over the long term is uncertain, the EIA's Trends and Expectations Surrounding the Outlook for Energy Markets forecasts LNG exports to be lower due to lower international oil prices and an increase in foreign gas production. These circumstances lead to an increase in U.S. gas storage levels.

Another factor that will decrease production costs is an improvement in technology for Carbon Capture and Sequestration. There is still hope the CCS technology can be better utilized to improve extraction levels. The DOE has appropriated more than \$7B grants since 2008, helping to fund the studying of CCS and how to make the technology viable.

100 EIA. (2020, October). Short-Term Energy Outlook - Natural Gas. Retrieved November, 2020, from <https://www.eia.gov/outlooks/steo/archives/oct20.pdf>



10.1.4 High Demand Storyline

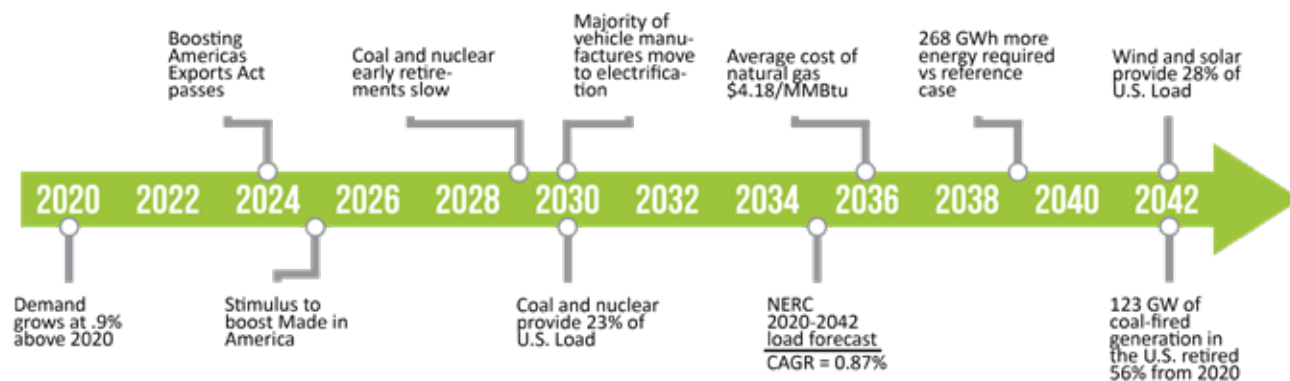


Figure 10.1.4-1: High Demand Timeline

Population Growth Results in Increased Demand

The High Demand scenario is based on assumptions from the 2020 EIA AEO High Economic Growth case where it examined the impact of population and non farm labor productivity growth assumptions, which are altered, yielding changes in the growth of non farm employment, real disposable income and real GDP, among other macroeconomic effects. The High Economic Growth case assumed that population growth would be 0.7% and real GDP was assumed to be 2.4% compared to 0.5% and 1.9%, respectively, for the EIA AEO Reference case. Disposable income and labor force are also higher than the reference. Multipliers were developed that are then applied to the Status Quo demand and energy forecast. The demand CAGR for MISO-IN-KY for the High Demand scenario is 0.5% compared to 0.2% in Status Quo.

Legislation Encourages U.S. Manufacturing and Exports

Buying American-made products has become increasingly necessary in 2020, especially as the country experienced a disruption in the supply chain during the COVID-19 pandemic. The Trump administration proposed several bills to encourage manufacturers to keep operations and productions within the U.S., satisfying a demand for product that may have been imported prior to the pandemic. U.S. trade deals are also encouraging suppliers to purchase within the country. The High Demand scenario is reflective of this increase in demand.



Auto Industry Shifts to Electrification

With the global push to reduce carbon emissions, pressure is building for vehicle manufacturers to shift focus to electrification. Manufacturers are rushing to improve battery technology that will give daily drivers an economical and clean transportation option. Transportation companies and public fleets across the country are also committing to moving to 100% electric fleet in the near future. These changes will result in an increase in retail and commercial demand for electricity.

High Demand Signposts

Historically, when the Federal Reserve lowers rates, an increase occurs in the GDP, reflecting an economic upturn. This is consistent with the economic assumptions in the High Demand scenario. Recent events have also shown an increase in the housing market. Prior to 2020, the Tax Reduction Act increased levels of disposable income and created an uptick in demand due to both the aforementioned events.

On December 16, 2019, Illinois Congresswoman Cheri Bustos introduced the Boosting America's Exports Act, to strengthen the economy and foster more American production and manufacturing. Likewise, the U.S. Senate also introduced similar legislation. Both the Trump and Biden administrations have committed to additional economic stimuli and policies which they claim will mobilize American manufacturing and innovation.

The World Economic Forum estimates that by the end of 2020, London will have some 20,000 electric vehicles, which could increase to 100,000 in the subsequent five-year span. Bloomberg also estimated that, by 2022, electric vehicles will be competitive with their internal-combustion counterparts driving EV sales to account for 35% of all new vehicle sales by 2040. In addition, on September 23, 2020, California's Governor Gavin Newsome signed an executive order phasing out all new gasoline-powered vehicle sales by 2035. All these events are drivers to the High Demand scenario outlined earlier.

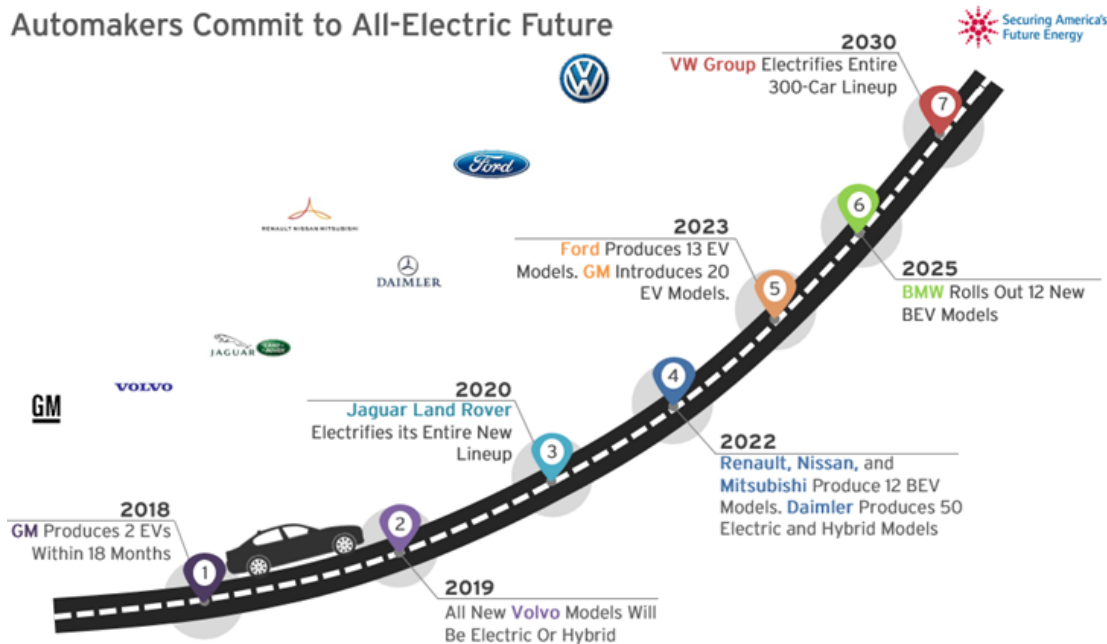


Figure 10.1.4-2: Automakers Electric Future Timeline ¹⁰¹

¹⁰¹ The FUSE. (2017, December 5). Automakers Commit to All-Electric Future [Digital image]. Retrieved April 27, 2021, from <https://energyfuse.org/safe-fact-pack-highlights-significant-growth-u-s-ev-market/>



Figures 10.1.4-3 and 10.1.4-4 compare the High Demand scenario growth with the Status Quo scenario for the North American load forecast.

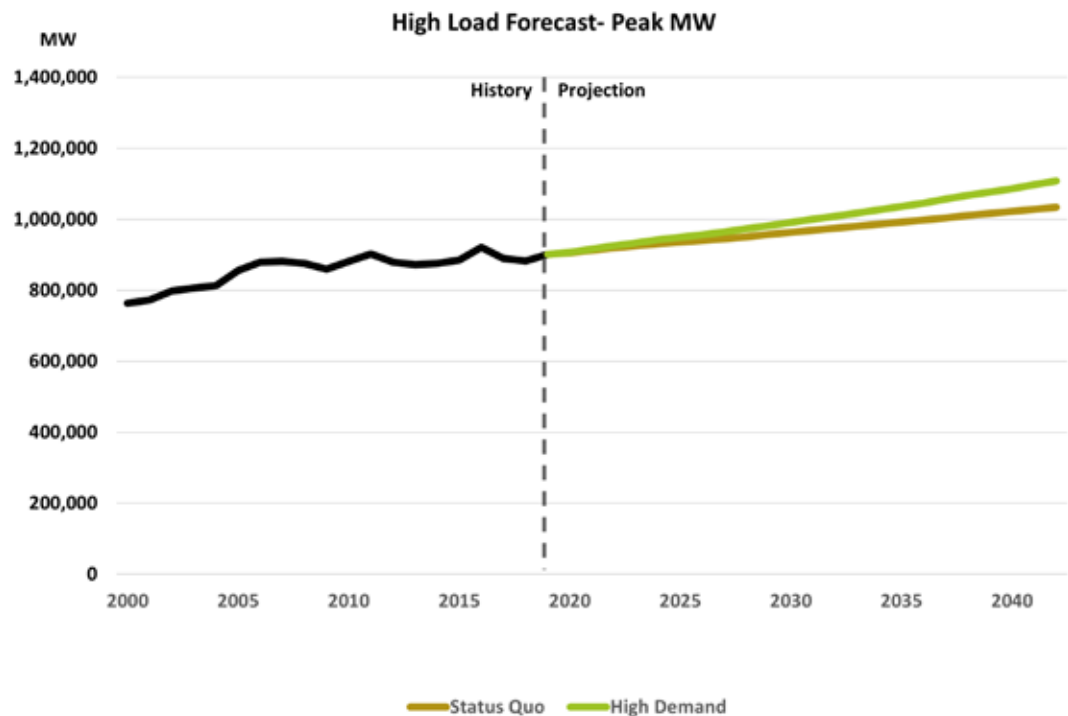


Figure 10.1.4-3: High Demand - Peak Load Forecast

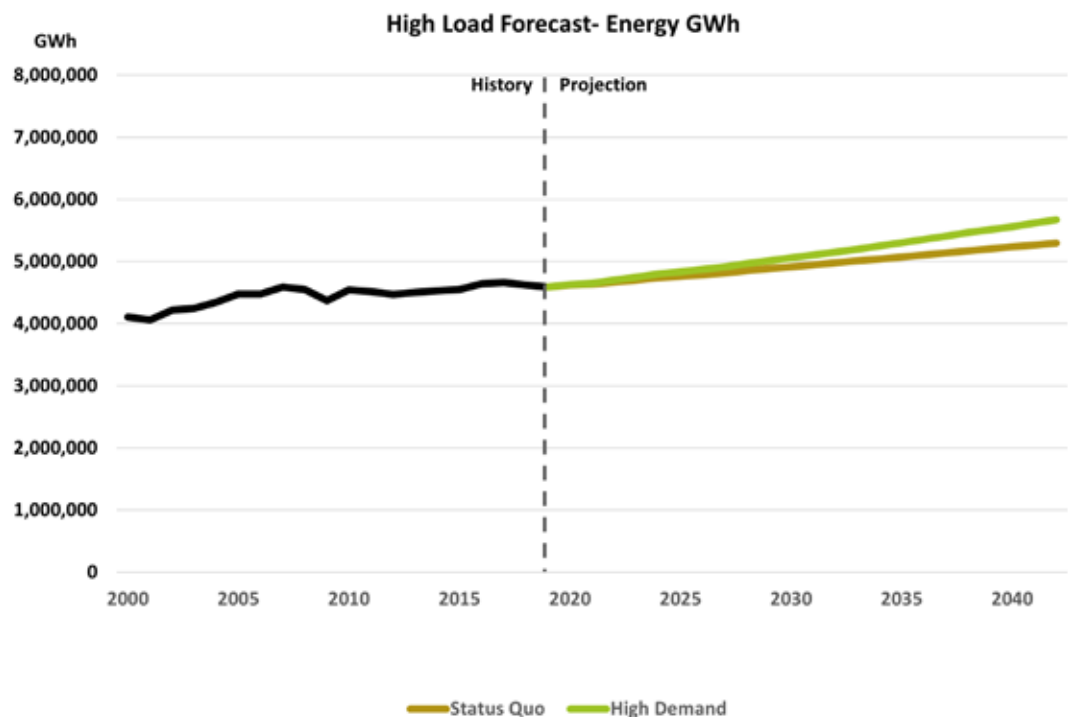


Figure 10.1.4-4: High Demand - Energy Load Forecast



10.1.5 Low Demand Storyline

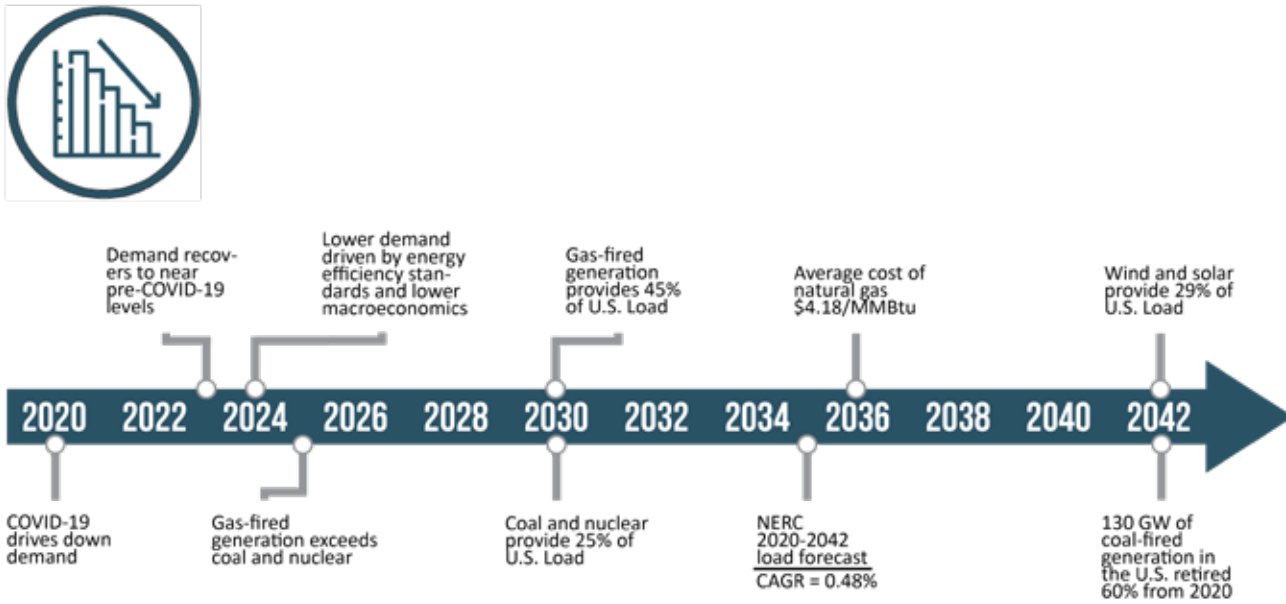


Figure 10.1.5-1: Low Demand Timeline

The Low Demand scenario is based on assumptions from the 2020 EIA AEO Low Economic Growth case where it examined the impact of population and non farm labor productivity growth assumptions, which are altered, yielding changes in the growth of non-farm employment, real disposable income and real GDP, among other macroeconomic effects. The Low Economic Growth case assumed that population growth would be 0.4% and the real GDP was assumed to be 1.4% compared to 0.5% and 1.9%, respectively, for the EIA AEO Reference case. Disposable income and labor force are also lower than the reference. Multipliers were developed that are then applied to the Status Quo demand and energy forecast. The demand CAGR for MISO-IN-KY for the Low Demand scenario is 0.1% compared to 0.2% in Status Quo.

The Low Demand scenario reflects a 5% decrease in demand in 2020 to reflect the impact of COVID-19. Demand through 2024 continues to be down by 2% before flattening out.

Lingering Effects of the COVID-19 Pandemic

As the effect of COVID-19 continues its ripple effect across the world, analysts are trying to understand the long-term impact the energy industry will see as a result. In the near term, manufacturing and production facilities are seeing the largest impact, causing a decrease in industrial demand for electricity which trickles down to local utility companies. This decrease outweighs the increase in residential customer demand of electricity from at-home workers and home-schoolers.



Efficiency Standards Impact Demand

The Department of Energy (DOE) has established various energy-efficiency standards for certain appliances and equipment that include over 60 different consumer, commercial and industrial, lighting, plumbing, and other products. Along with the federal government efficiency standards, some states are also setting their own standards. Efficiency standards encourage manufacturers to employ smart technologies that will save consumers on their energy bills and also reduce demand for energy.

Distributed Generation Trending Upwards

The United States has more than 12 million distributed energy resources (DERs), about one-sixth of the capacity of the nation's power plants. Contributing to this growth is the dramatic decrease in the cost of DER technology, as well as governmental and utility incentives for installations. The number of units is trending upward for both commercial and residential sectors and may include common distributed energy resources such as solar panels, wind turbines, natural-gas-fired fuel cells, biomass combustion, hydropower, emergency backup generators, or reciprocating combustion engines. DERs allow individual customers and communities greater control over their energy usage and help to replace traditional grid infrastructure. DERs also assisting with a reduction in energy losses and utility peak shaving.

Low Demand Signposts

Year-over-year demand continues to decline from a number of factors: energy efficiency, BTM, and reduced energy consumption from commercial and industrial load due to macroeconomic impacts. Figure 10.1.5-2 shows the load forecast for the years 2000-2042.

Energy Star has partnered with over 40% of Fortune 500 companies to deliver energy efficiency solutions saving American consumers over \$35B in energy costs equating to over 4 trillion kilowatt-hours (kWh) of electricity since 1992. The Northwest Power and Conservation Council boasts that federal efficiency standards were responsible for a 20% reduction in energy demand in 2014 and expects an additional reduction of 1,200-1,500 MW by 2035. The EPA has developed a National Action Plan Vision that establishes a goal of achieving all cost-effective energy efficiency by 2025, and it presents ten goals to advance the plans recommendations. Many states across the nation have followed suit by developing more stringent building codes and providing tax incentives to encourage an increase in energy efficiency that is directly impacting demand.

The uncertainty caused by the pandemic has also caused many businesses to put a pause on expansions and previously planned projects. According to the International Energy Agency (IEA), the world has seen electricity demand drop to consistent off-peak levels due to lockdowns and reductions to industry and service levels. COVID-19 is directly responsible for a 4% drop in electricity demand in 2020.

DERs are experiencing additional growth. According to GTM Research, U.S. distributed solar installations are expected to grow from roughly 2.0 million in 2018 to almost 3.8 million in 2022. BTM battery storage is also predicted to grow in that period from around 200 MW to nearly 1,400 MW.



Figures 10.1.5-2 and 10.1.5-3 compare the Low Demand scenario growth with the Status Quo scenario for the North American load forecast.

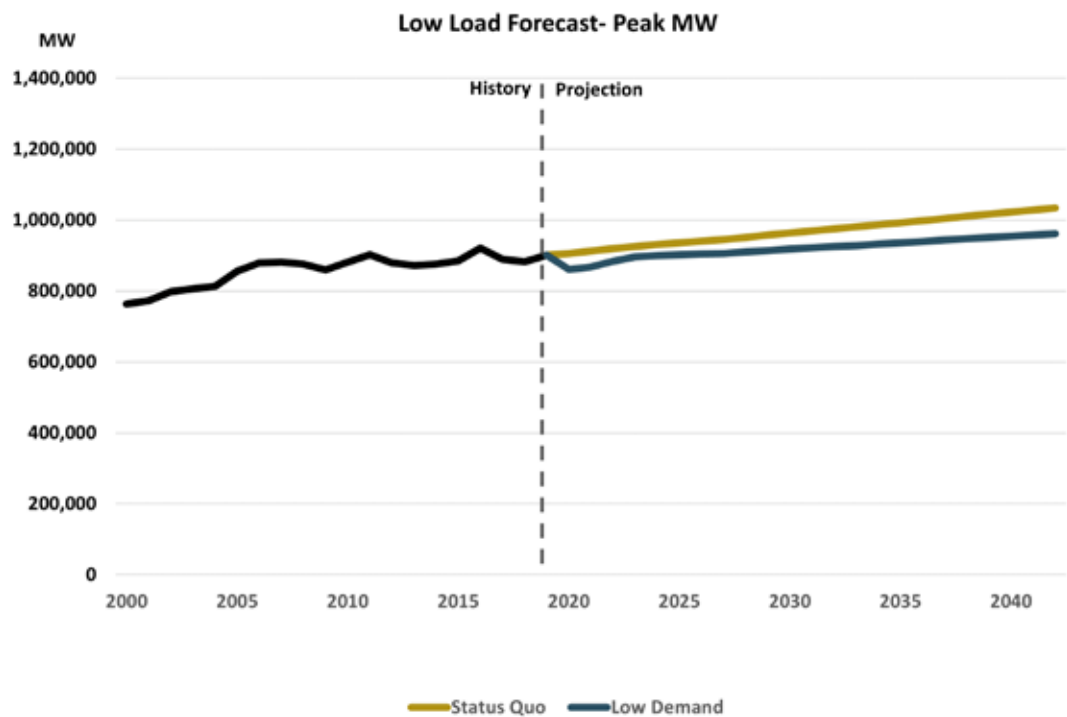


Figure 10.1.5-2: Low Demand - Peak Load Forecast

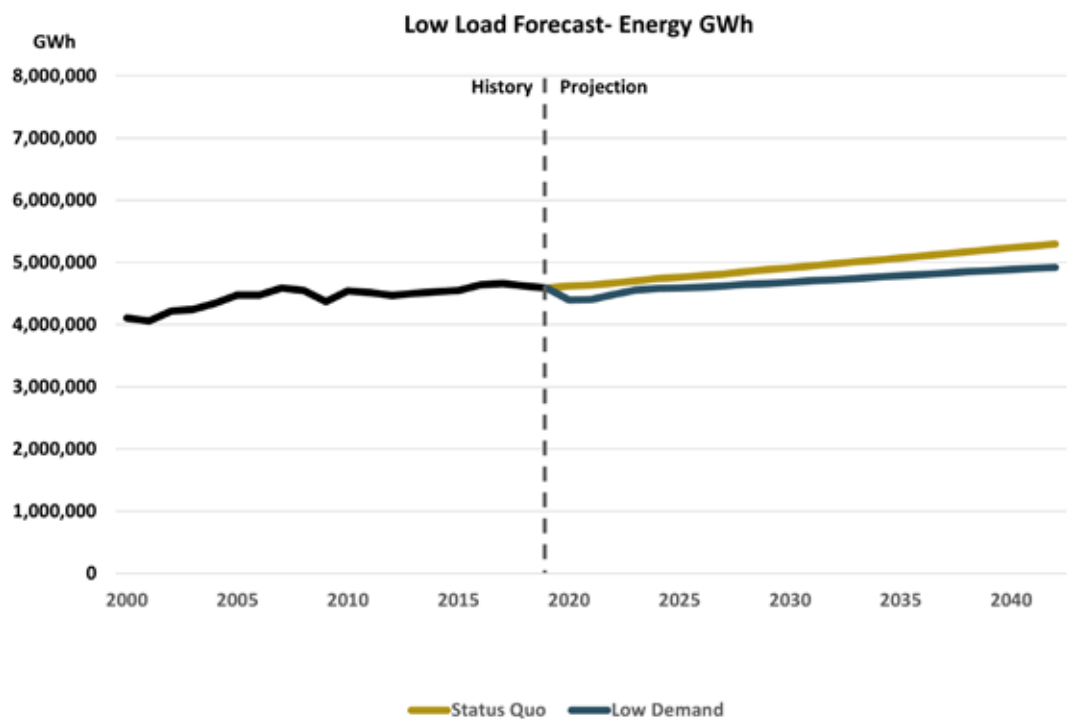


Figure 10.1.5-3: Low Demand - Energy Load Forecast



10.1.6 Zero Carbon Additions Storyline

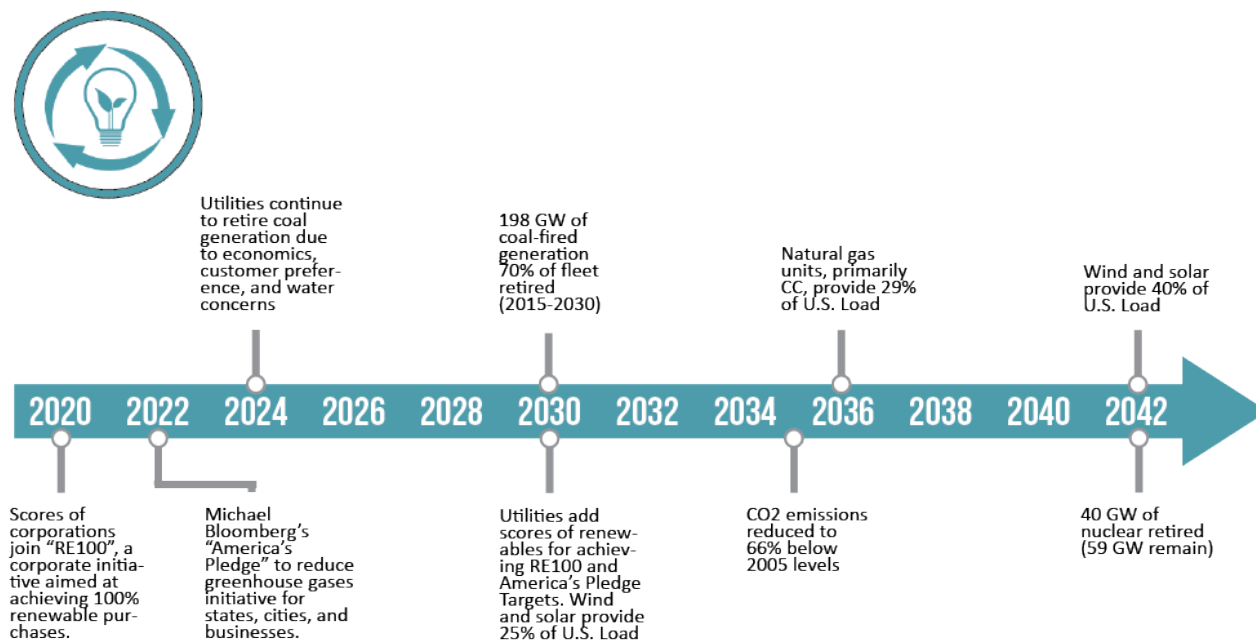


Figure 10.1.6-1: Zero Carbon Additions Timeline

The Zero Carbon Additions scenario is driven by corporations and states pledging to be net-zero carbon emissions by a certain time frame. These range from aggressive target dates of 2030 to 2040.

In order to capture the outlook for the continued commitment of net-zero carbon emissions, the Zero Carbon Additions scenario does not allow the addition of carbon-emitting resources. This causes the acceleration of economic retirements of carbon-emitting resources. Existing nuclear resources are assumed to stay online despite economics in order to meet the net-zero carbon targets.

One aspect of the Zero Carbon Additions scenario is that it assumes higher levels of energy efficiency and demand response to reflect their contribution as viable resources. BTM penetration levels are up to reflect the corporate and societal commitment to reduce carbon emissions. Before BTM penetration, demand growth is a CAGR of -1.0%. BTM represents 15% of total generation by 2050, so the load levels served by the front-meter is significantly reduced.



Figure 10.1.6-2 compares the Zero Carbon Additions BTM generation with the Status Quo scenario for North America. Figure 10.1.6-3 shows the net impact on energy.

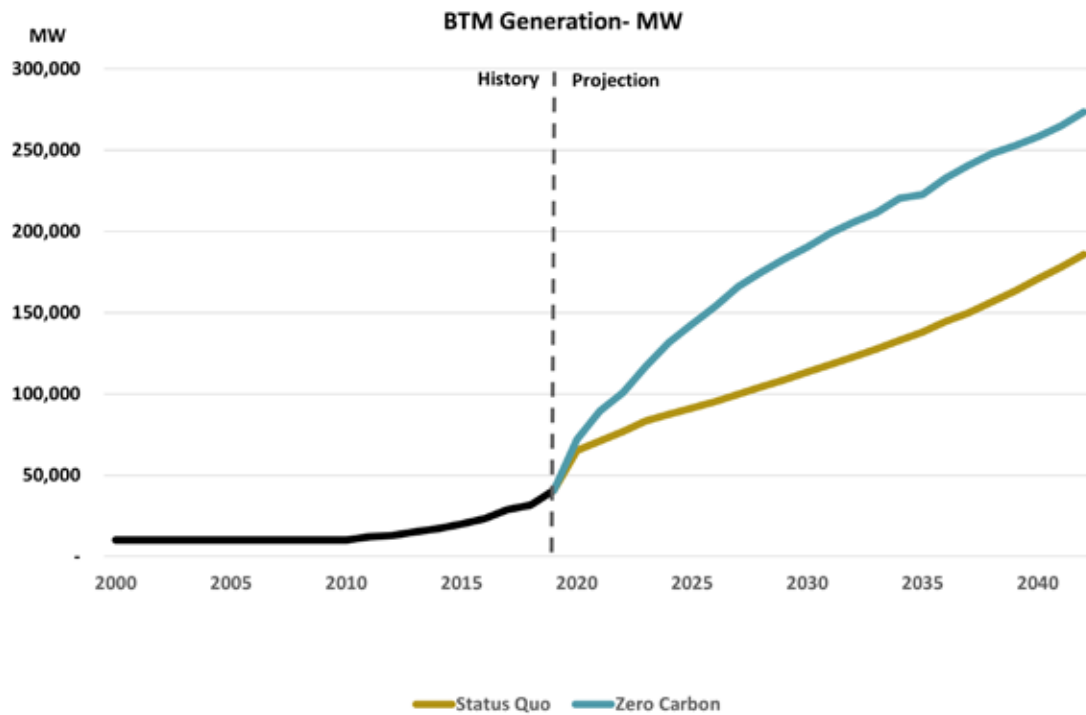


Figure 10.1.6-2: Zero Carbon BTM Generation (MW)

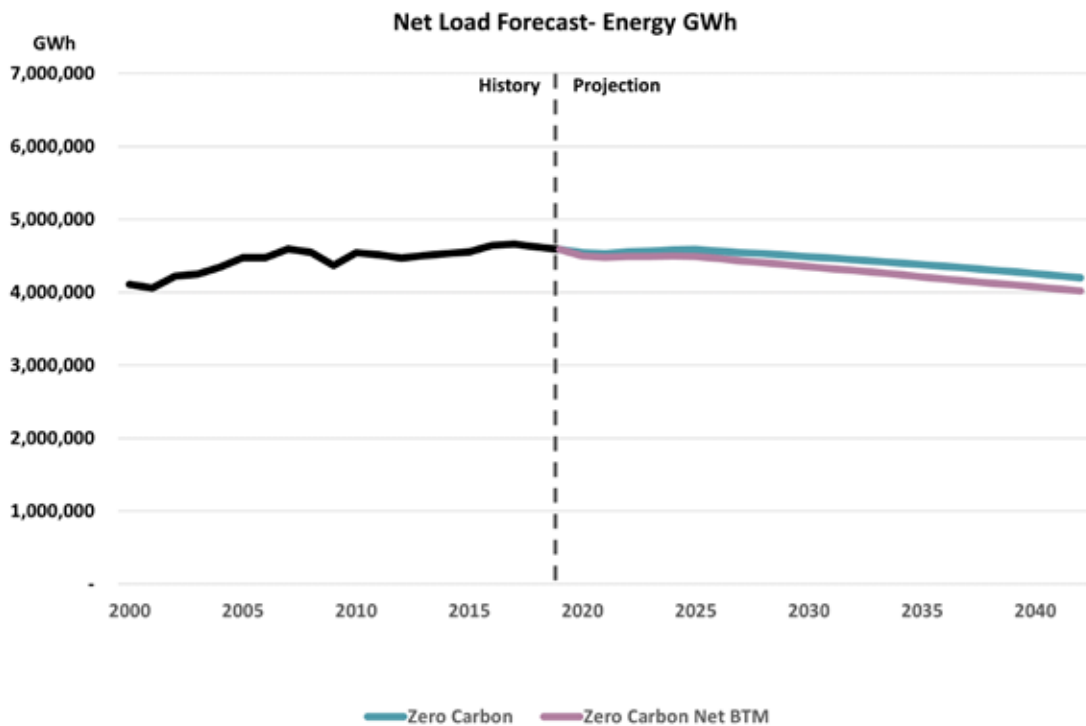


Figure 10.1.6-3: Zero Carbon - Energy Net Load After BTM (GWh)



Efforts Toward 100% Renewable Energy

Climate science teaches that the eventual extent of global warming is a product of the amount of carbon dioxide levels the world emits into the atmosphere. In order to mitigate this potential global environmental crisis, many groups, governments, and corporate entities are investing resources in renewable technologies and low carbon emission electricity production capabilities with the goal to eventually achieve the 100% decarbonization of the planet.

According to the IEA, the United States is expected to see an increase in renewable electric capacity additions in 2020 and 2021. The expiration of renewable tax credits in the United States is resulting in the pull-forward of project development timelines; however, the U.S. Federal government is expected to provide some flexibility, allowing projects to be commissioned through 2023 without losing their tax preferential treatment.

Retirements of Fossil Fuel Generation Facilities

The IEA estimates the most polluting fossil fuels (coal) to be responsible for one-third of global warming. World leaders are working to develop plans and incentives to transition existing coal-fired plants to ones using renewable resource generation.

Zero Carbon Additions Signposts

Over fifteen states and U.S. territories, including Washington, California, Nevada, Colorado, New Mexico, Hawaii, Wisconsin, Virginia, New York, New Jersey, Connecticut, Rhode Island, Maine, Washington DC, and Puerto Rico, have adopted 100% clean energy legislation or executive action as of April 2020. Additionally, over a dozen U.S. electric utilities have announced similar clean energy policies.

The renewable electricity PTC has bolstered renewable projects across the nation that are set to phase out by the end of 2023, creating a rush over the next few years to complete currently scheduled projects. Along with this many nations and financial institutions have pledged to comply with the UN Secretary-General Antonio Guterres's urge to end coal financing, contributing further to the transition to a zero carbon future.

The EIA estimates CO₂ emissions from coal fell 14.6% in 2019, contributing to a 2.8% drop in total energy-related emissions. The drop in emissions mirrored a 16% decline in coal generation, as electricity production from the fuel fell to its lowest level since 1976. Various power companies to include, Alliant Energy Corp., Great River Energy, Arizona Public Services, Vistra, and others announced in 2020 plans to retire over 13 U.S. coal plants.

A growing list of fortune 500 companies have joined together as the world's most influential companies into what is known as the RE100, committing to 100% renewable electricity by 2050. Members include Apple, 3M, Capital One, General Mills, Intel, Lego Group, Microsoft, PepsiCo, and others for a total of 264 companies.



Figure 10.1.6-2 portrays states that have adopted RPS and states that have committed or are pushing for 100% RPS.

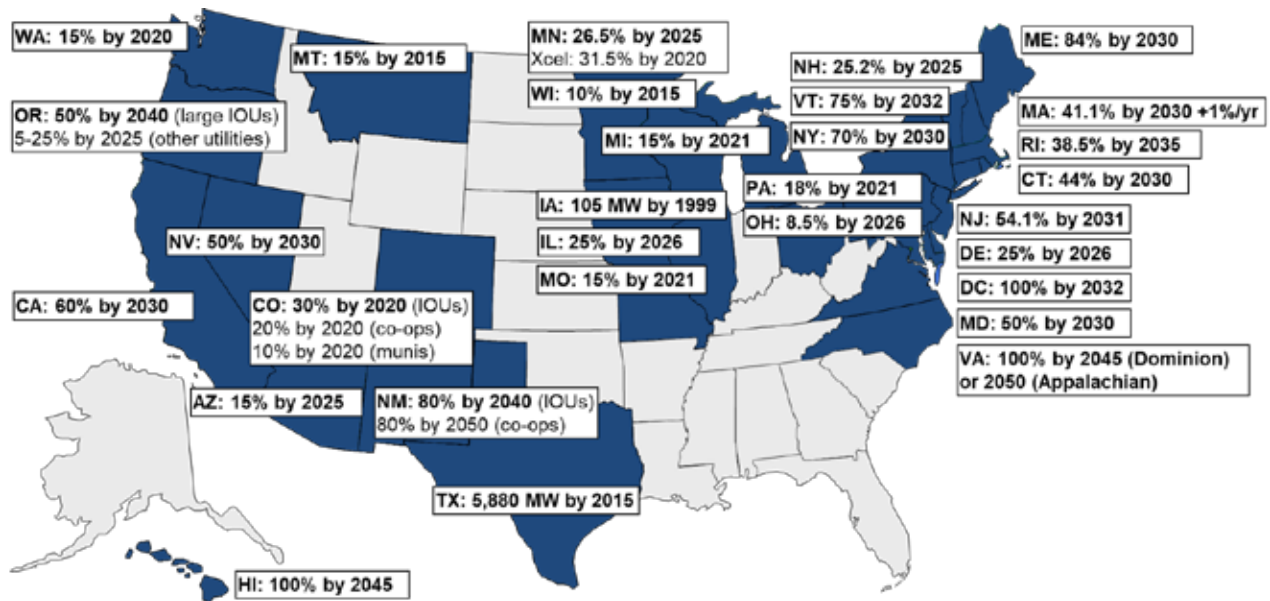


Figure 10.1.6-4: States that Adopted 100% Renewable Goals/Targets¹⁰²

As has been seen in recent years where renewable capacity additions have outpaced gas-fired additions, the Zero Carbon Additions scenario assumes this trend will continue without the backdrop of carbon pricing for incentives. When investigating the new construction projects in the EIA-860M for June 2020, zero carbon resources are more than double that of carbon-emitting resources with a total capacity of 78 GW compared to 36 GW.

102 Environment America. (n.d.). States that Adopted 100% Renewable Goals [Digital image]. Retrieved October, 2020, from <https://environmentamerica.org/feature/ame/100-renewable#:~:text=We%27re%20now%20supporting%20100,%2C%20Pennsylvania%2C%20Wisconsin%20and%20Virginia.>



10.1.7 High Natural Gas with Carbon Limit Storyline

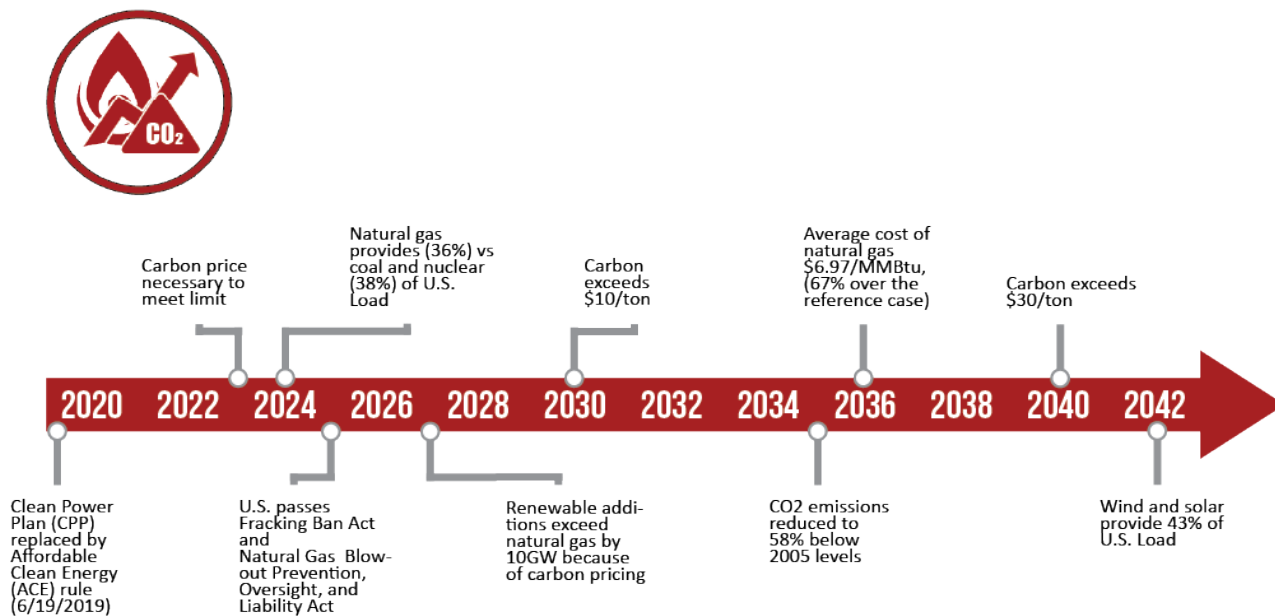


Figure 10.1.7-1: High Natural Gas Timeline

The storyline for the High Natural Gas with Carbon Limit is the same as the High Natural Gas scenario with the exception that a carbon limit is introduced in 2022, reflecting an 80% reduction in carbon emissions from 2005 levels by 2050. The carbon limit trajectory is consistent with the U.S. rejoining the Paris Climate Accord.

Figure 10.1.7-2 provides a comparison of the Status Quo scenario natural gas price and the High Natural Gas scenario gas price. The 2nd Y-Axis is the U.S. carbon limit trajectory. The U.S. power sector target is 444 million short tons by 2050.



High Natural Gas with Carbon Limit Signposts

The signposts for the High Natural Gas scenario will also apply here but will include additional signposts for CO₂ limits. H.R.763 was introduced in 2019 by Florida Representative Theodore Deutch to impose fees on the carbon content of fossil fuels, to include crude oil, natural gas, and coal that may be used to emit greenhouse gases. Numerous other House and Senate bills have been introduced and are expected to be debated in future sessions.

In June 2019, the EPA replaced the CPP with the ACE rule establishing guidelines to limit CO₂ from electric generating units. President Joe Biden has outlined in his climate plan that he is a strong supporter of the Green New Deal. On the first day of his administration, President Biden rejoined the Paris Climate Agreement.

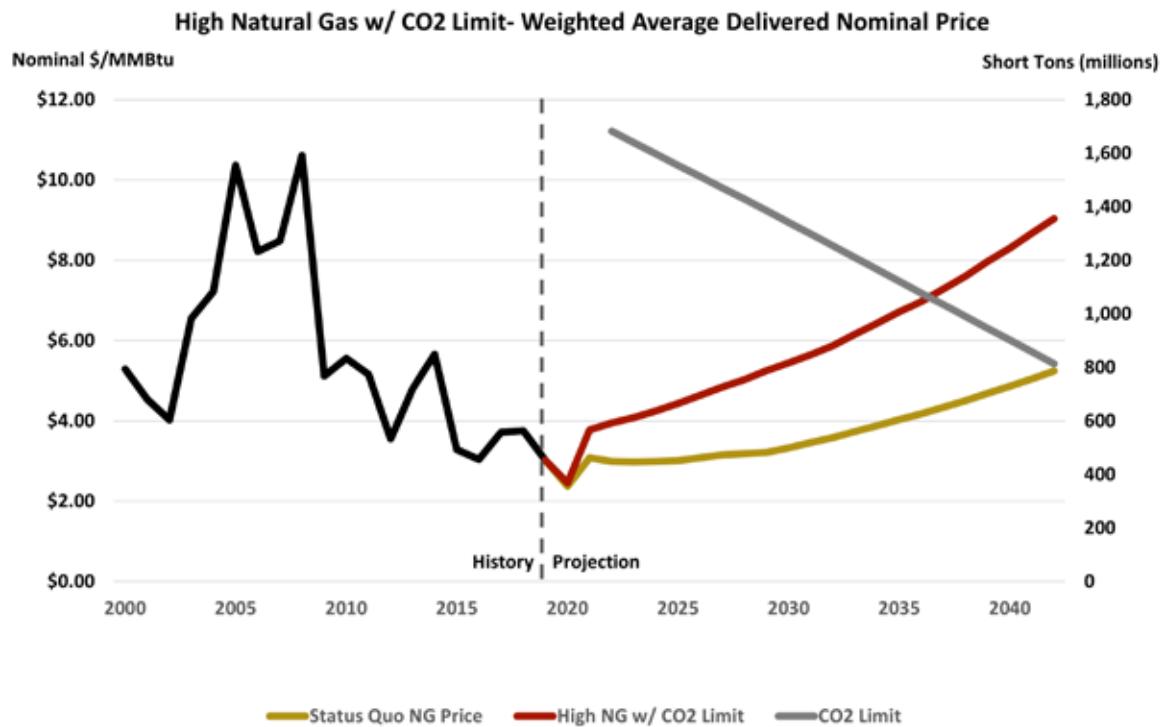


Figure 10.1.7-2: High Natural Gas with CO₂ Limit - Weighted Average Delivered Nominal Price



10.1.8 Low Natural Gas with Carbon Limit Storyline

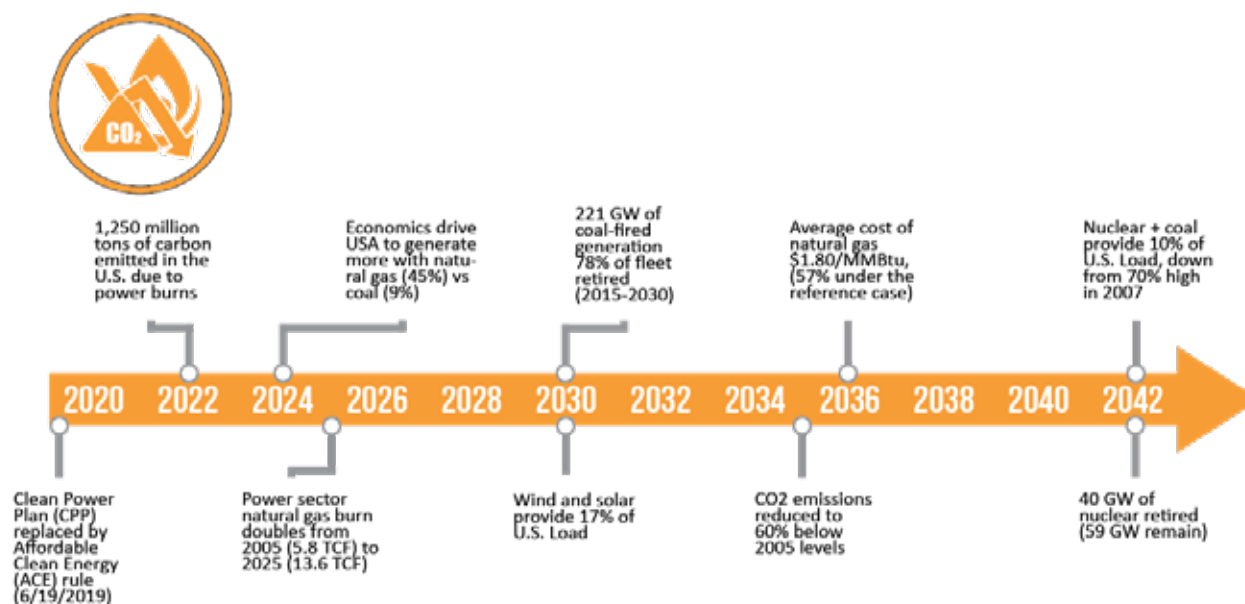


Figure 10.1.8-1: Low Natural Gas Timeline

The storyline for the Low Natural Gas with Carbon Limit scenario is the same as the Low Natural Gas scenario with the exception that a carbon limit is introduced in 2022, reflecting an 80% reduction in carbon emissions from 2005 levels by 2050. The carbon limit trajectory is consistent with the U.S. rejoining the Paris Climate Accord.

Figure 10.1.8-2 provides a comparison of the Status Quo scenario natural gas price and the Low Natural Gas scenario gas price. The 2nd Y-Axis is the U.S. carbon limit trajectory. The U.S. power sector target is 444 million short tons by 2050.

Low Natural Gas with Carbon Limit Signposts

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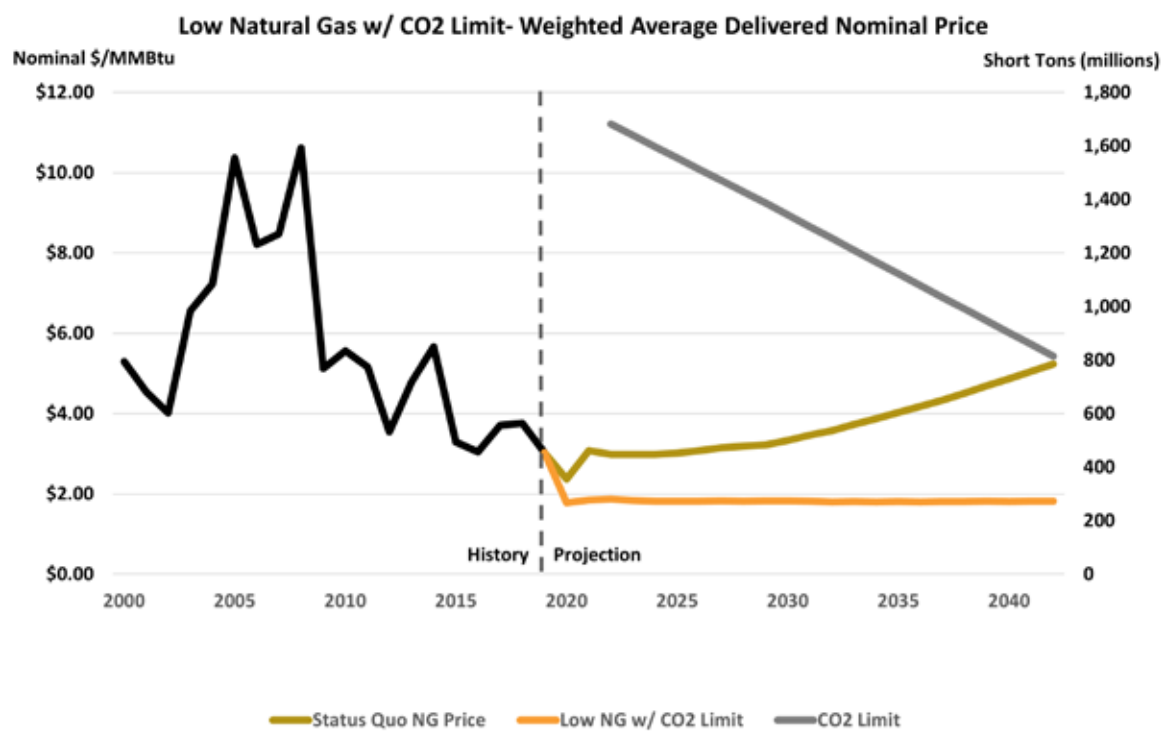


Figure 10.1.8-2: Low Natural Gas with CO2 Limit - Weighted Average Delivered Nominal Price



10.1.9 National Carbon Tax Storyline

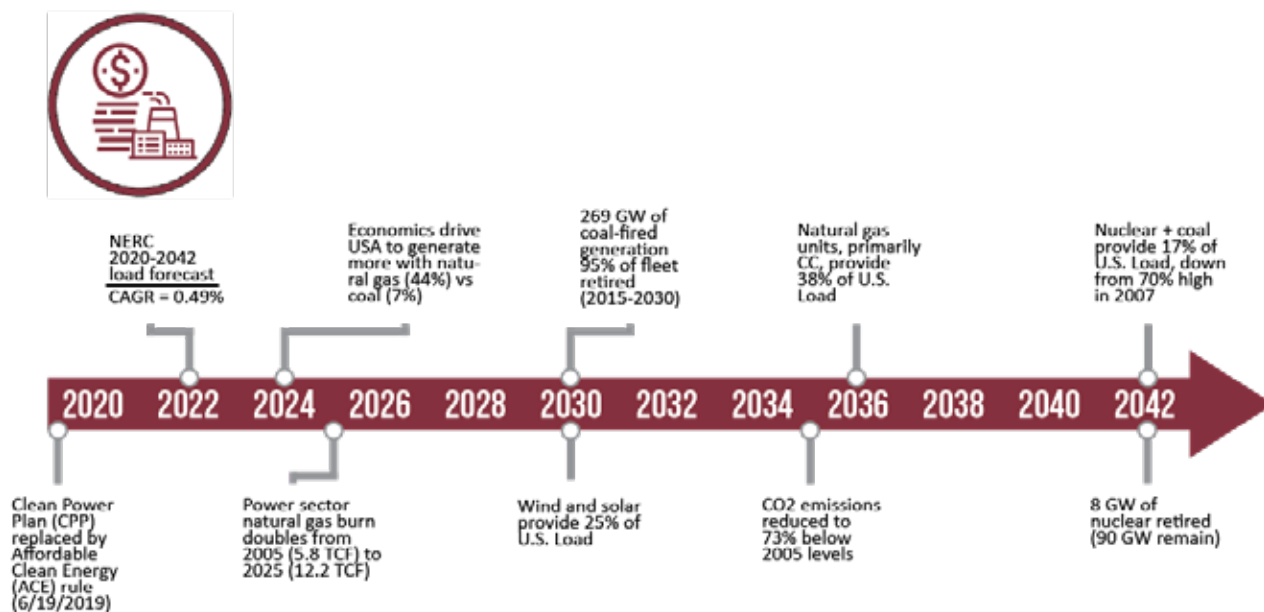


Figure 10.1.9-1: National Carbon Tax Timeline

The carbon prices in the National Carbon Tax scenario are consistent with the 2020 EIA AEO \$15 Carbon Fee Case with the exception that post-2030 prices increase annually at 2.5% instead of 5.0% above inflation. This scenario reflects the imposition of a fee/tax. Natural gas prices are slightly higher than Status Quo scenario until 2045 when reduced natural gas demand results in slightly lower prices. Demand is also down due to the pressure associated with higher consumer bills reflecting a pass-through of the tax. Demand in MISO-IN-KY results in a CAGR of 0.1% down from 0.2% in Status Quo scenario.

Carbon taxes are levied on the burning of fossil fuels such as coal, oil, and natural gas. The point of the carbon tax is that it acts to incentivize reducing and eventually eliminating fossil fuel usage that is responsible for climate destruction. This incentive aims to encourage policy-makers, corporations, and individuals to reduce carbon emissions through conservation, substitution, and innovation. Users of fossil fuels will have to pay for releasing the harmful carbon dioxide they emit.

National Carbon Tax Signposts

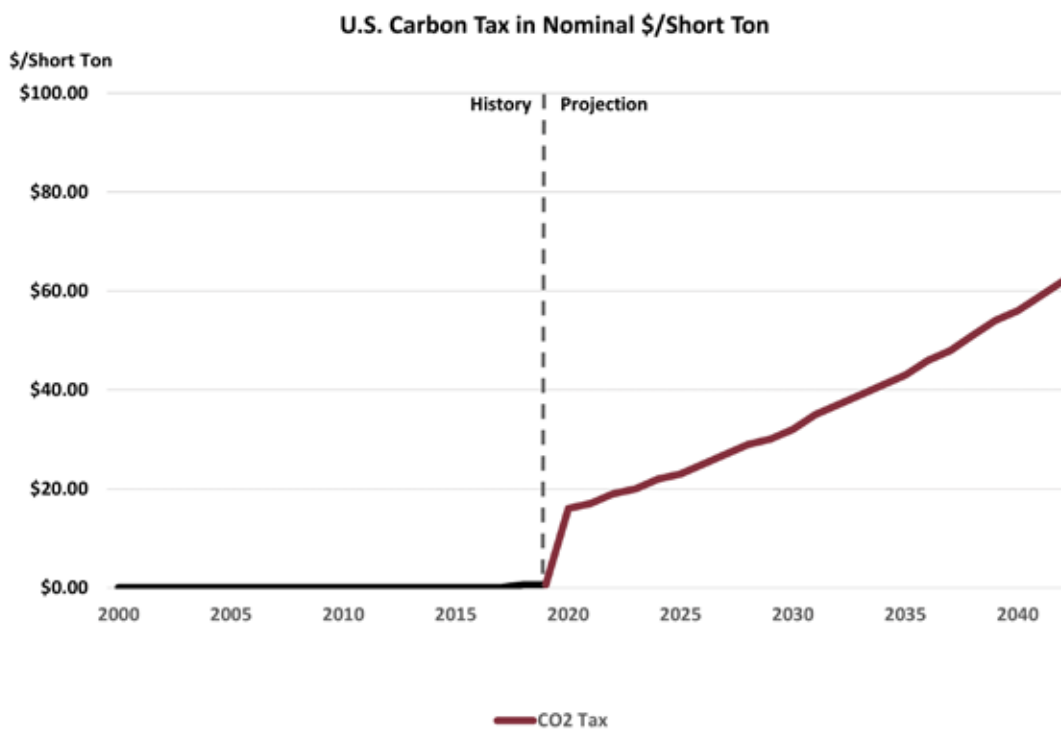
The 116th Congress has introduced eight carbon legislation bills as shown in Table 10.1.9-1. The Energy Innovation and Carbon Dividend Act and Climate Action Rebate Act are both similar to the \$15/short ton assumption in the National Carbon Tax scenario. Several of these bills have been introduced previously pointing to further signs that there may be momentum for a national carbon policy. In addition, four of the bills are bipartisan.

**Table 10.1.9-1: 116th Congress Carbon Legislation**

Carbon Pricing Bill	Pricing Mechanism	Initial Tax Rate	Annual Adjustments	Starting Year
America's Clean Future Fund Act	Carbon Fee	\$25 per metric ton (\$2022)	\$10 + inflation	2023
Energy Innovation and Carbon Dividend Act	Carbon Fee	\$15 per metric ton (\$2020)	\$10 + inflation	2020
American Opportunity Carbon Fee Act	Carbon Fee	\$52 per metric ton (\$2020)	6% + inflation	2020
Stemming Warming and Augmenting Pay Act	Carbon Fee	\$30 per metric ton (\$2021)	5% + inflation	2021
Climate Action Rebate Act	Carbon Fee	\$15 per metric ton (\$2020)	\$15 + inflation	2020
Raise Wages, Cut Carbon Act	Carbon Fee	\$44 per metric ton (\$2020)	2.5% + inflation	2020
America Wins Act	Carbon Fee	\$52 per metric ton (\$2020)	6% + inflation	2020
MARKET CHOICE Act	Carbon Fee	\$35 per metric ton (\$2021)	5% + inflation	2021

On October 15th, 2020, FERC made a clarification that FERC has jurisdiction over organized wholesale market rules that may incorporate a state-determined carbon price.

The EIA released a report in March 2020 showing the effect carbon fees would have on carbon dioxide emissions. The report discusses three carbon fee cases beginning in 2021, and in all cases, there is a reduction in carbon dioxide emissions in the near term that eventually level off.

**Figure 10.1.9-2: U.S. Carbon Tax (\$/MWh)**



10.2 Scenario Summary

The Scenario Drivers of the nine scenarios are summarized in Table 10.2-1. Each of the key drivers identified in the left-hand column was categorized as: medium, higher, really high, low, and really low.

For example, coal price was assumed to be really high in the High Natural Gas scenario to reflect a correlation between natural gas price and coal. When natural gas price is really high, coal will dispatch more as it becomes the marginal fuel a greater percentage of the time. Since there is more coal burn, then the law of supply and demand theory dictates the coal price is higher, in this scenario it was assumed to be really high. In the same scenario, we see an increase in solar, wind, and storage generator additions. These are generation additions that occur as renewables and storage become more profitable when natural gas prices are really high.

Table 10.2-1: Scenario Drivers

	Status Quo	High Natural Gas	Low Natural Gas	High Demand	Low Demand	Zero Carbon Additions	High Natural Gas with CO2	Low Natural Gas with CO2	National Carbon Tax
Load	➡	➡	➡	⬆	⬇	⬇	➡	➡	➡
Natural Gas Price	➡	⬆	⬇	➡	➡	➡	⬆	⬇	➡
Coal Price	➡	⬆	⬇	➡	➡	➡	⬆	⬇	⬆
Technologies									
Nuclear Economic Retirements	Staggered beg. 2022					None			
Nuclear License	60 Years					60 Years			80 Years
Coal Economic Retirements	Staggered beg. 2022					Unlimited	All eligible beg. 2021		
Natural Gas Additions	CA Limited					Limited	CA Limited		
Natural Gas Retirements	Staggered beg. 2022					Unlimited	All eligible beg. 2025	All eligible beg. 2021	
Hydro	Existing								
Geothermal	Existing								
Other Renewables	Existing								
% of Generation Additions									
Solar	48%	↗	⬇	➡	⬇	➡	⬆	↗	↗
Wind	8%	↗	⬇	➡	⬇	➡	⬆	↗	↗
GT	11%	➡	⬆	↗	⬇	⬇	➡	➡	⬇
CC	28%	➡	↗	⬆	⬇	⬇	⬇	➡	⬇
IC	1%	➡	↗	↗	⬇	⬇	➡	⬆	⬇
Storage	4%	↗	⬇	➡	⬇	⬆	↗	↗	↗
Distributed Generation	➡	↗	⬇	⬇	➡	↗	⬆	↗	↗
Carbon	State/Province						Limit	Limit	Tax

➡ Medium ⬆ Higher ⬆ Really High ⬇ Low ⬇ Really Low

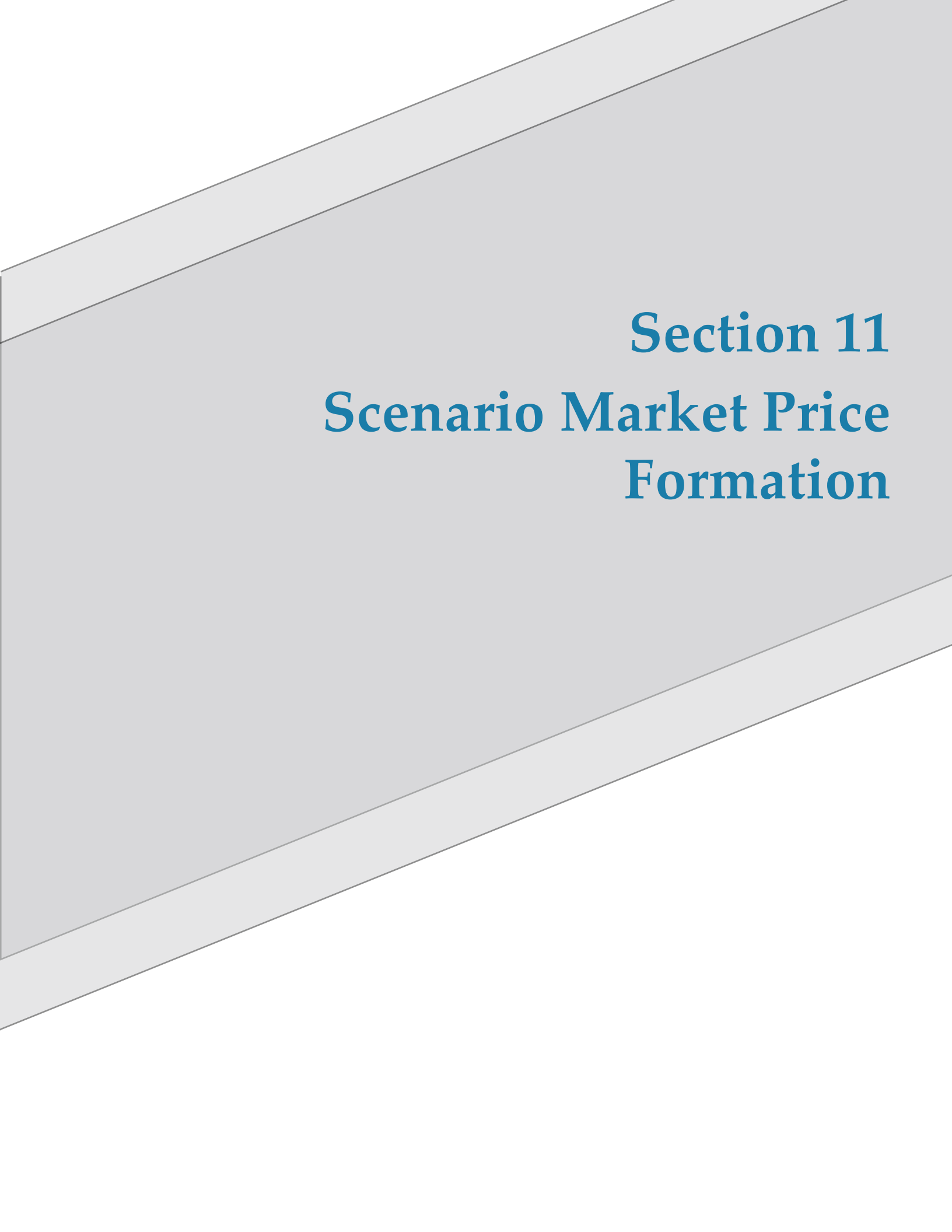


In Table 10.2-2, a brief description is provided for all scenarios, providing an easy compare and contrast.

For example, the High Natural Gas and High Natural Gas with CO₂ Limits scenario both use the same natural gas forecast. However, when CO₂ Limits are imposed, nuclear generation is no longer economically retired by the EnCompass model.

Table 10.2-2: Scenario Descriptions

	Status Quo	High Natural Gas	Low Natural Gas	High Demand	Low Demand	Zero Carbon Additions	High Natural Gas with CO ₂	Low Natural Gas with CO ₂	National Carbon Tax
Description	Base case driven by existing policies and technologies	High NG production cost coupled with restrictive legislation	Low NG production cost and enhanced recovery	Higher demand driven by economic upturn	Lower demand driven by energy efficiency standards and lower macroeconomics	No-fossil fired generation added; reduced technology cost	Same as High NG coupled with CO ₂ limit	Same as Low NG coupled with CO ₂ limit	National carbon tax legislation to address climate change
Economic Growth	GDP of 1.9%			GDP of 2.4%	GDP of 1.4%				
Demand Growth	MISO-IN-KY CAGR of 0.2%	MISO-IN-KY CAGR of 0.2%		MISO-IN-KY CAGR of 0.5%	MISO-IN-KY CAGR of 0.1%	MISO-IN-KY CAGR of -1%			MISO-IN-KY CAGR of 0.1%
Energy Efficiency	Current EES	Current EES			EES improvements	High EES coupled with increased demand response			
Carbon	State/provincial prices		State/provincial prices	State/provincial prices			CO ₂ limit to meet Paris Climate Accord	CO ₂ limit to meet Paris Climate Accord	Carbon tax of \$15/short ton increasing annually
Natural Gas Price	Settled prices through 2032 and trended thereafter forecast period average of \$3.52/MMBtu	Higher prices with forecast period average of \$5.74/MMBtu	Lower prices with constant nominal pricing of \$1.50/MMBtu	Settled prices through 2032 and trended thereafter forecast period average of \$3.52/MMBtu					Slightly higher prices than status quo with forecast period average of \$3.59/MMBtu lower post-2047
Coal Price	Status Quo from 2020 EIA AEO	Coal prices change consistent with the high and low gas recovery EIA cases		Status Quo from 2020 EIA AEO					Coal prices change consistent with the EIA \$15/ton carbon tax
Economic Retirements	Status Quo staggered beginning in 2022	Status Quo staggered beginning in 2022	Status Quo staggered beginning in 2022	Status Quo staggered beginning in 2022		Unlimited coal and gas retirements	All Eligible units advanced to beginning 2021	All Eligible units advanced to beginning 2021	
Nuclear Generation	Staggered economic retirements beginning in 2022 60- year license	Staggered economic retirements beginning in 2022 60-year license	Staggered economic retirements beginning in 2022 60-year license	Staggered economic retirements beginning in 2022 60-year license		No economic retirements 60- year license	No economic retirements 60- year license	No economic retirements 60- year license	No economic retirements 80- year license
Wholesale electric price	Medium-low	Medium	Low	Medium-low	Medium-low	Medium-low	High	Medium	Medium-high
Wholesale capacity price	Medium-high	Medium-high	High	Medium-high	Medium	Medium	Medium-low	Medium-low	Low



Section 11

Scenario Market Price Formation

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11. SCENARIO MARKET PRICE FORMATION

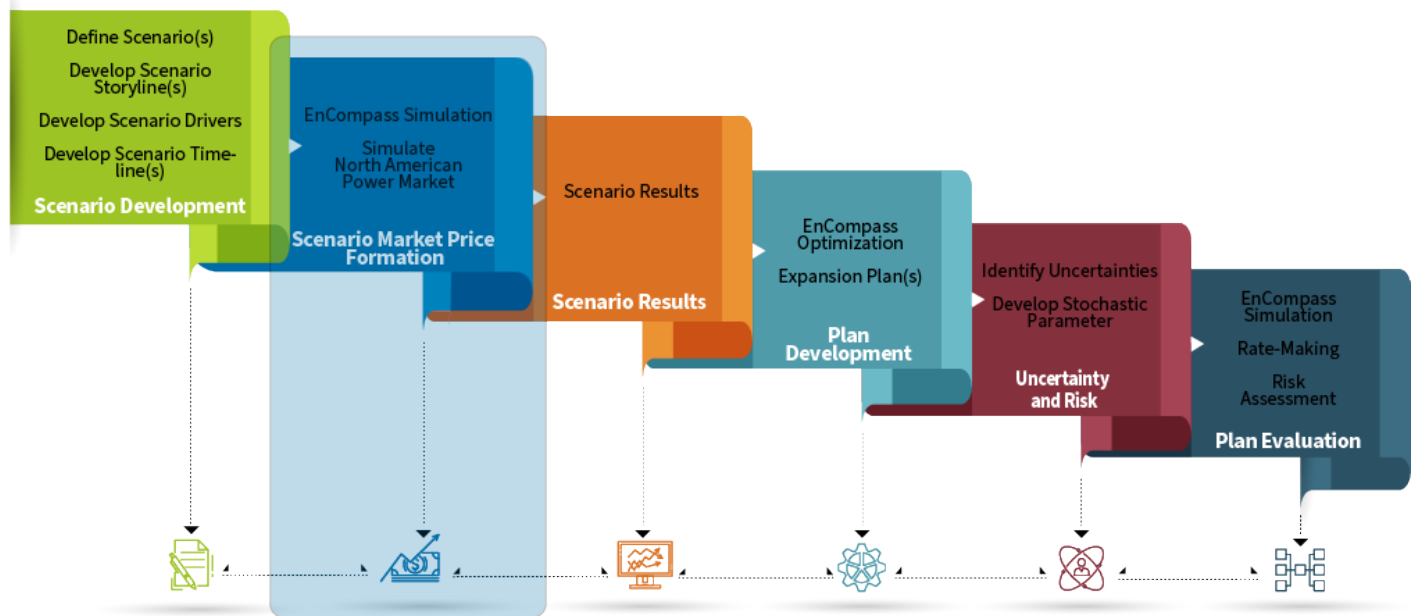
11.1 Modeling and Market Approach

Once the Section 10 Scenario Development storyline, timelines, and drivers have been developed, the next step is to make the scenarios actionable by modeling their unique characteristics in the EnCompass Market Simulation Module combined with the Horizons Energy National Database (NDB) and Horizons Energy Scenarios.

The future cost of energy, ancillary services, and capacity is one of the most critical aspects of utility planning. No longer can utilities simply plan as islanded entities, building for their own load in a vacuum. Planning must incorporate a reasonable and realistic projection of the market, including present and future policies and market rules.

KYMEA utilizes market price projections for all planning activities, from near-term hedging decisions to long-term planning. The integrated modeling approach creates a fundamental forecast that is internally consistent across supply, demand, fuels, emissions, and transmission drivers. This section of the report discusses KYMEA's methodology for creating the market price forecasts used in various aspects of its planning processes.

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11.2 EnCompass Market Simulation Module

The EnCompass Software permits large scale market simulations of the entire North American electric system, optimizing decisions across multiple commodities by minimizing costs while observing constraints and market rules. EnCompass creates a unique long-term resource plan for all of North America for each set of scenario drivers by considering capital projects, capacity, environmental programs, unit commitment and dispatch, ancillary services, and unit outages.

EnCompass – Energy and Ancillary Services Co-Optimization

As part of a standard simulation, EnCompass calculates the marginal cost (shadow price) of meeting energy and ancillary service requirements. This is equivalent to a system lambda type of calculation that considers incremental fuel and variable costs, but not startup or no-load costs. EnCompass has an option to dynamically adjust energy and ancillary bids to account for these costs and minimize the amount of uplift that would be needed to make generators whole.

In market simulation runs, BAs are selected, and their resources and capital projects are utilized to meet energy, capacity, and ancillary service requirements, subject to transmission constraints and environmental program limits at the least total cost. Prices are calculated for energy, ancillary services, and environmental programs with limits. In general, the prices represent the marginal costs associated with meeting the imposed limits. If the load requirements were increased by 1 MW in 1 hour, the price in that hour represents the increase in overall costs to meet that additional load.

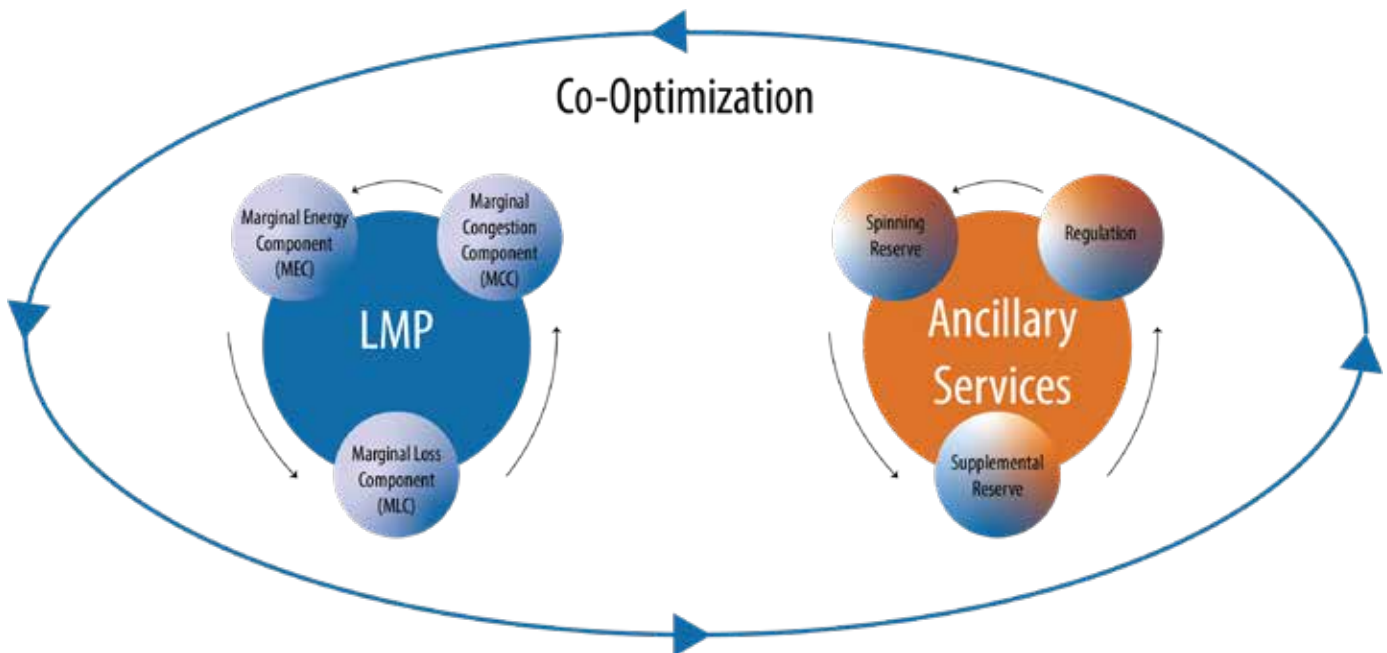


Figure 11.2-1: Energy and Ancillary Services Co-Optimization Flow



The marginal energy costs do not consider the costs associated with being committed and online, only the incremental dispatch costs. In ISO markets such as MISO and PJM, bids will be submitted, and prices set so that commitment and dispatch costs can be completely recovered through energy and ancillary service prices. To model this, EnCompass iteratively determines the bids and resulting prices that make generators “whole.” Resources that must be committed will be evaluated during the iterative bidding process; contract sales and payback resources (storage and demand response) are not considered. For all periods in which a commitment decision was made (number of units online is greater than the minimum), revenues from energy and ancillary service sales are compared against the bids for commitment, dispatch, and ancillary services. If the revenue did not cover the bids and the resource was dispatched or provided ancillary services during the period, a bid adder is calculated for dispatch and ancillary services to try and increase prices and close the gap. Another simulation is performed with commitment schedules held in place, but the new bid adders applied. This process is repeated until all resource commitment periods cover their bids or are no longer dispatching or providing ancillary services.

Ancillary Services

In addition to providing energy to end-consumers, power system operators are also responsible for ensuring system reliability. As more intermittent renewable generation is added, replacing dispatchable fossil generation, the value of ancillary services will grow. To this end, power markets maintain an array of ancillary services to ensure it is always possible to balance the supply and demand for energy in real-time. The ancillary services calculated in the EnCompass process are:

■ Spinning Reserves

Spinning Reserves are intended to help the system respond quickly to forced outages or other contingency events. Spinning reserves are provided by generation units that are online, but are not generating at full capacity and can increase their output quickly to provide additional capacity to the system. Typically, generation units must be able to fully ramp up their generation within 10 to 15 minutes of receiving instructions to do so, depending on the details of the market.

■ Supplemental Reserves

Supplemental Reserves are also intended to help the system recover from unplanned contingencies; however, supplemental reserves can also be provided by generation units that are offline if they are able to start up and increase their output to the target level within a predefined period, usually 10 to 30 minutes, depending on the market. Online units with available capacity can also provide supplemental reserves. The amount of supplemental reserve capacity in a system is often calculated, inclusive of any surplus spinning reserve capacity. The sum of spinning and supplemental reserves is collectively referred to as Supplemental Reserves.

■ Regulation Service

Regulation service is used to balance small fluctuations constantly and automatically in supply and demand in real-time. Generation units that are providing regulation service must be able to respond to automatic generation control (AGC) signals from the system operator and change their output accordingly on very short time scales, typically on the order of one to several seconds.

- Regulation-up (capacity that is available to increase output)
- Regulation-down (capacity that is available to decrease output)



In the EnCompass market simulation runs, a zonal topology is created to forecast market prices. There are 78 defined zones in the Horizons Energy national database, which were described earlier in Section 9 of this report. For the MISO topology, there are ten market price zones or areas in the national database. For capacity planning in the MISO market, there are also ten local resource zones or capacity markets as described in the upcoming pages of this report. In the NDB, the zonal market areas and the capacity markets are identical.

The third market topology is the MISO ancillary services topology shown in Figure 11.2-2. The eight MISO ancillary services regions are modeled in the NDB to calculate regional values for spinning reserves, supplemental reserves, and regulation service.

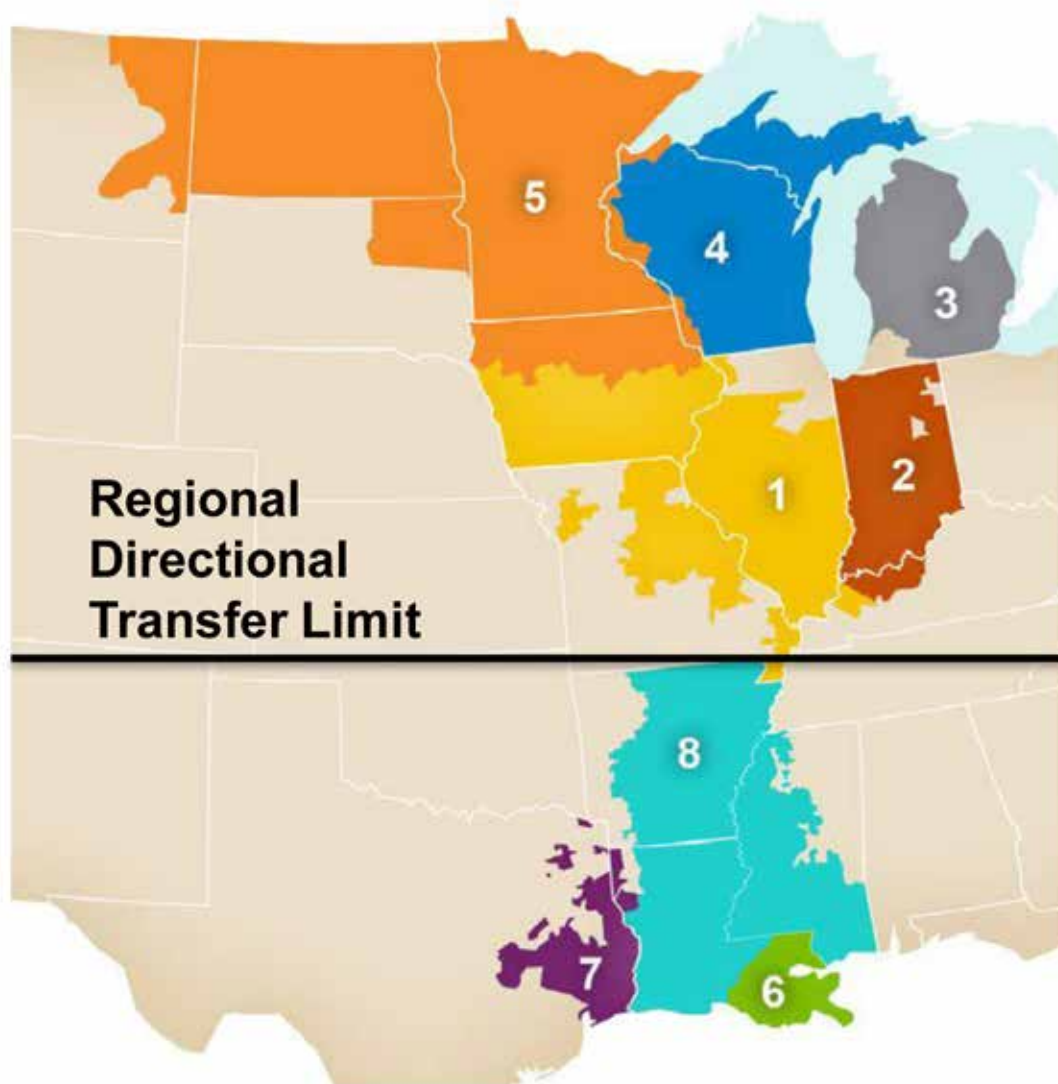


Figure 11.2-2: MISO Ancillary Services Map¹⁰³

103 MISO Energy and Ancillary Services Co-optimization (Rep.). (2019, September 24). Retrieved April 27, 2021, from MISO website: http://www.ercot.com/content/wcm/key_documents_lists/187700/4._MISO_Energy_and_Ancillary_Service_Co-optimization_091819.pdf



11.3 Horizons Energy National Database

Complete EnCompass databases for North American power markets have been developed by Horizons Energy. With these databases, EnCompass can be used to forecast energy, ancillary service, capacity, emission allowances, and renewable energy to the year 2050. Other market metrics can be produced including hourly generator operations, transmission flows, and congestion costs.

Zonal Markets

As a market participant in both the MISO and PJM, KYMEA is interested in projected zonal energy and capacity price curves for two specific market zones (MISO Indiana.Hub and PJM AEP-Dayton.Hub); however, to capture the market impact of both regional capacity/energy mixes as well as national policies such as a carbon cap, the entire North American footprint is modeled. Figure 11.3-1 illustrates the interconnections surrounding the MISO zonal markets highlighted in red.

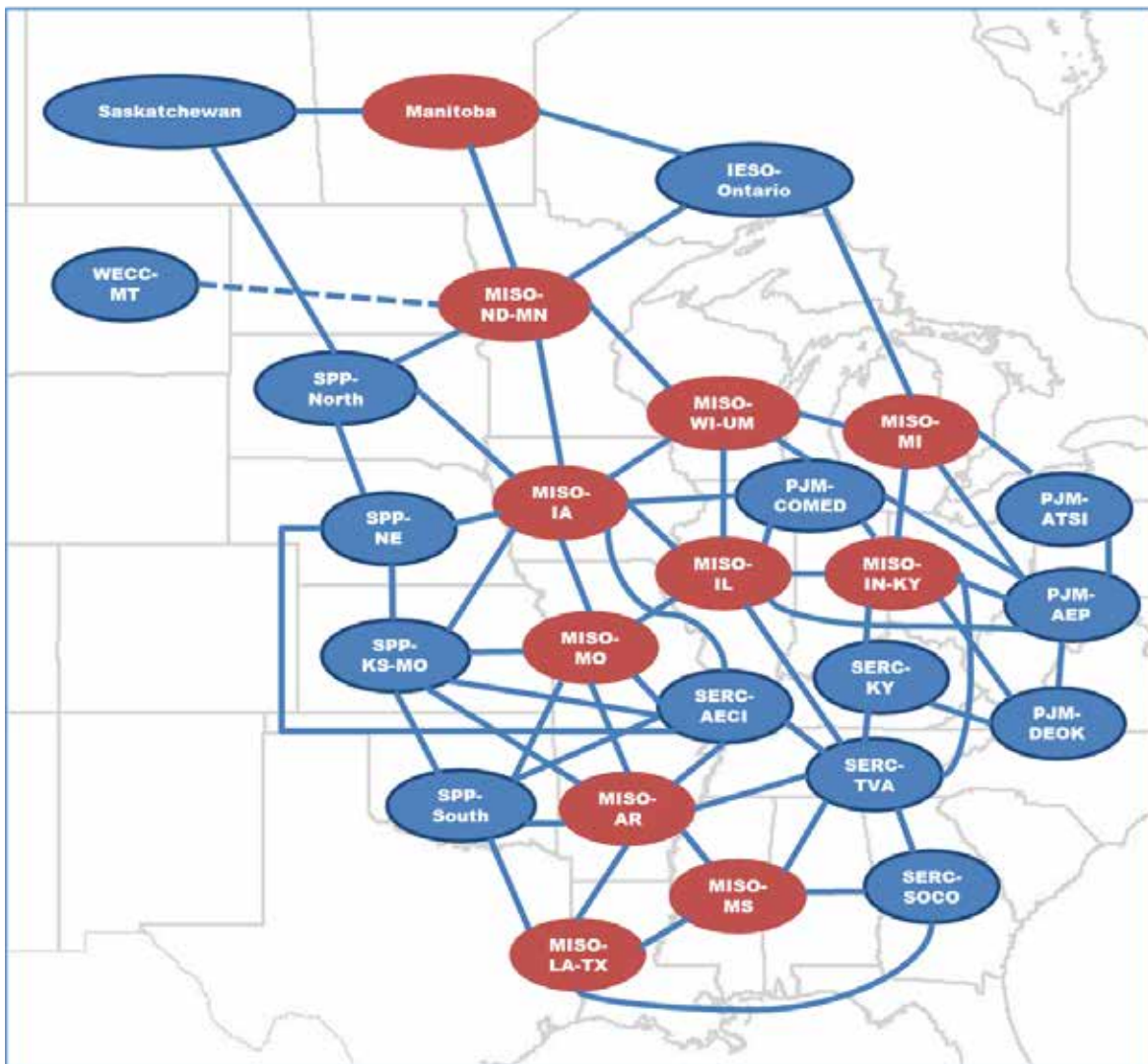


Figure 11.3-1: MISO and Interconnected Zonal Markets



Fundamental Market Modeling

The simulation of market prices is referred to as fundamental market modeling. Fundamental market models include forecast hourly loads, tens of thousands of resources of all technologies and fuel types, delivered fuel costs, unit heat rates and outages, transmission paths and costs, environmental programs, and many other fundamental drivers of power markets. Fundamental models provide insight into market prices, volatility, fuel usage, emissions, etc. In Section 12, Scenario Results, the fundamental results for the nine scenarios provide a projection of the resource mix, fuel burn, CO₂ emissions, capacity additions and retirements, and market prices for each of the plausible futures.



11.4 Definition of Spot and Forward Prices

The spot price is the settled price between buyers and sellers looking to make an immediate purchase or sale. The forward price is the market's expectation today for a price and quantity to be exchanged sometime in the future. Successful price forecasting requires that the distinction between spot and forward prices is understood because misapplication can result from using spot prices as forward prices and vice versa. On the surface, the distinction seems easy enough. A spot price represents the price of a commodity at immediate delivery. In our everyday life, most of our purchases – including a meal at a restaurant, a hammer at the hardware store, and gasoline from the corner station – are transacted at spot prices.

Hourly Spot Prices

Hourly spot prices can be very volatile. As the EnCompass model simulation marches through time, an hourly settlement or spot price is calculated. This price represents the marginal generation point at which the load purchases all its energy, aka, the market clearing price. The desired outcome of the modeling endeavor is to mimic the operation and nuances of the power market as closely as possible. The specific regional or RTO market rules such as ancillary service requirements, bidding behavior, and market caps are included in the modeling effort.

Electricity prices often exhibit “jumps” in price. A jump is a stochastic occurrence that has discrete movements with arrival times tied to high loads, low supply, high fuel costs, and constrained transmission. Figure 11.4-1 illustrates that, while the hourly price is between \$16.00 and \$64.50 (two standard deviations), there are times the hourly prices can jump higher. Capturing the jumps will be discussed further in the MISO Operating Reserve Demand Curve discussion in this section of the report.

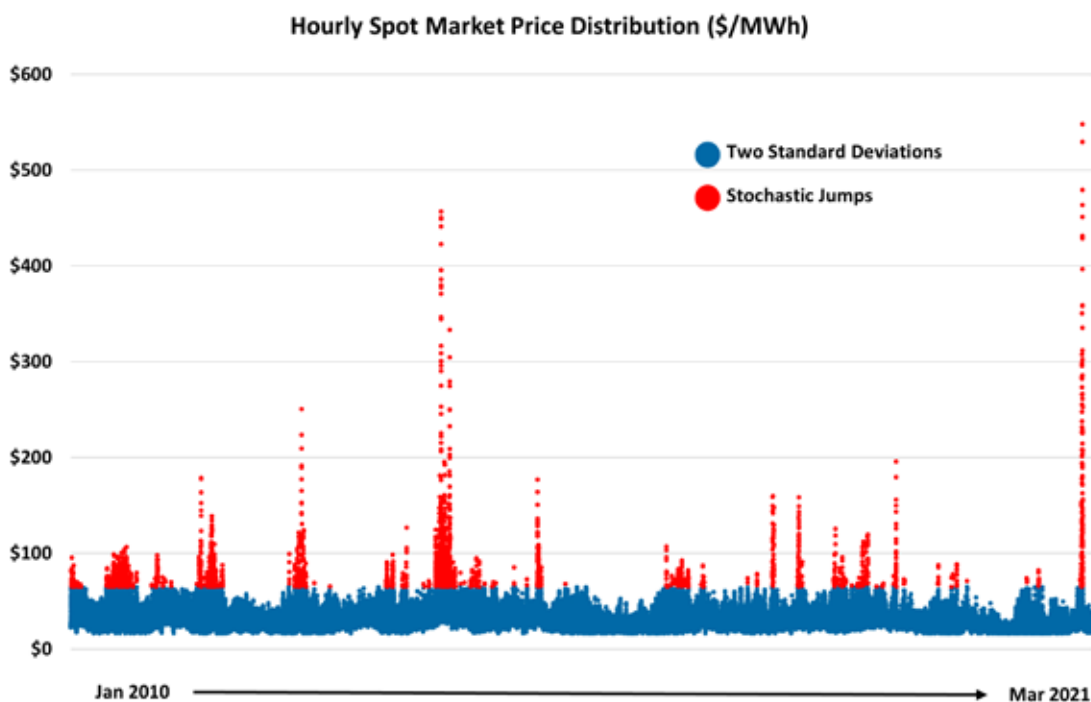


Figure 11.4-1: LGEE Hourly Spot Market Price Distribution



Zonal and Nodal Price Definitions

The EnCompass market model permits both zonal and nodal simulation. For zonal, a transportation model is used, which assumes no congestion within an area, and completely dynamic transfers can be made among connected areas. For nodal, a DC powerflow is employed over a topology defined with buses and branches, like those used in transmission planning models such as PSS/E, PowerWorld and GE-PSLF.

Nodal Prices

As part of the day-ahead (DA) market clearing process, MISO and PJM use a security constrained unit commitment solution (SCUC) and a security constrained economic dispatch solution (SCED) where 99% of the resources are committed in the DA market. These are computer intensive solutions that require elaborate transmission modeling to provide nodal prices. For long-term planning, nodal models require detailed geographic and electrical assumptions of the resources, load, and transmission system. Nodal models are generally limited to a minimal number of scenarios and years due to the computational time requirements of the software and hardware making it difficult to perform scenario and stochastic analysis in a timely fashion.

Zonal and Nodal Equivalent Prices

As discussed earlier, KYMEA uses a zonal topology to solve for hourly spot market clearing prices for multiple scenarios and years across the entire North American electricity footprint where zones are separated by flow gate transmission constraints. However, KYMEA is also interested in the nodal prices at the specific nodes shown in Figure 11.4-2.

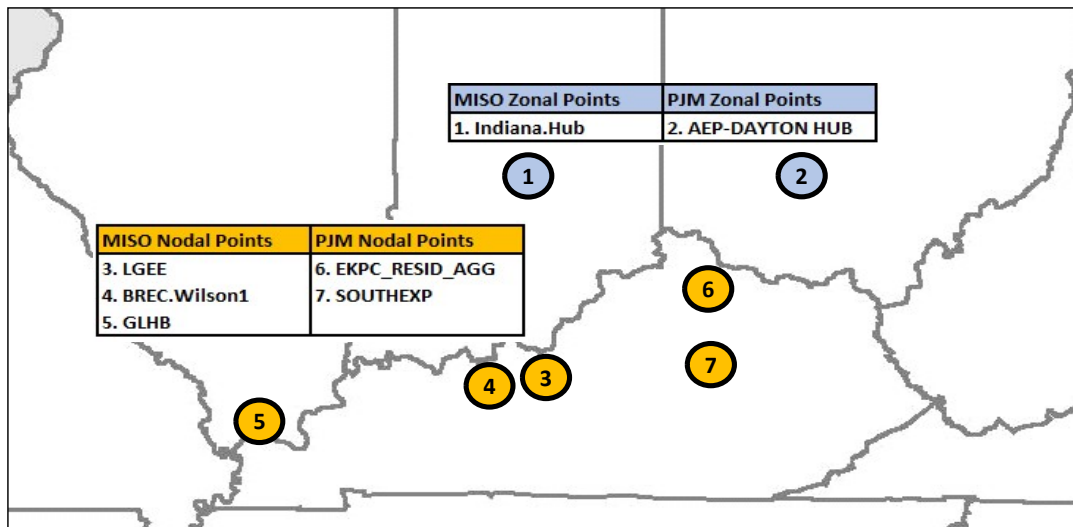


Figure 11.4-2: Zonal and Nodal Price Points of Interest

KYMEA's methodology is to solve for zonal prices and then apply hourly basis spreads to the zonal price based on historical hourly spreads. Figures 11.4-3 and 11.4-4 summarize the hourly spreads by on and off peak, by month, for the LGEE node compared to the Indy.Hub zone. While this method relies heavily on past historical basis spreads, correlation, and volatility, it is flexible enough to incorporate time series adjustments to reflect changes in the resource mix and transmission infrastructure. Since KYMEA is interested in nine scenarios as well as multiple stochastic simulations for up to 20 years, the basis spread technique is the preferred solution.

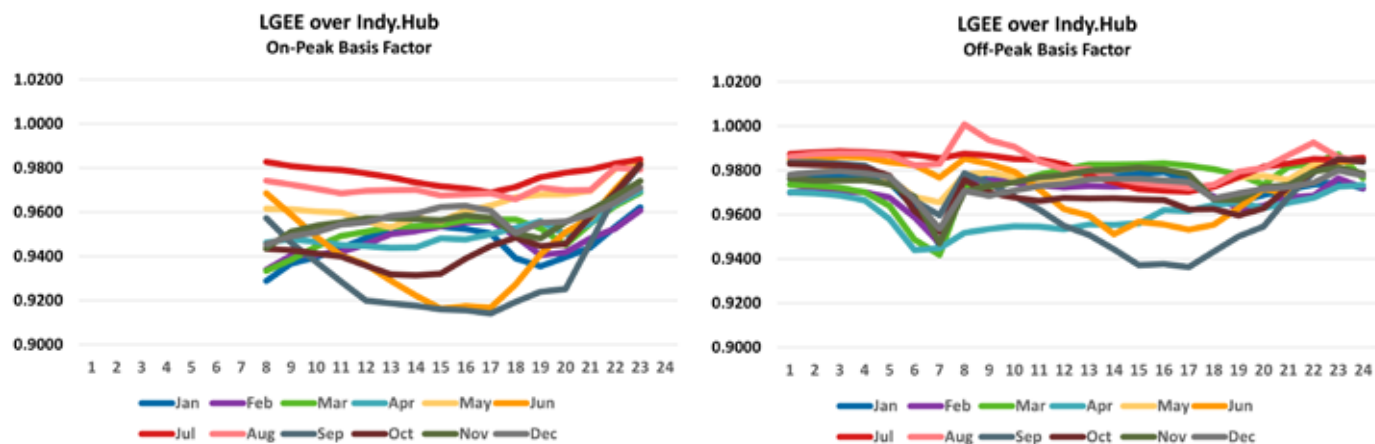


Figure 11.4-3: LGEE Over Indy.Hub Basis Factor

Monthly Spot Prices

The monthly spot market prices exhibit a log-normal distribution. The impact of the stochastic jumps described earlier positively skew the prices.

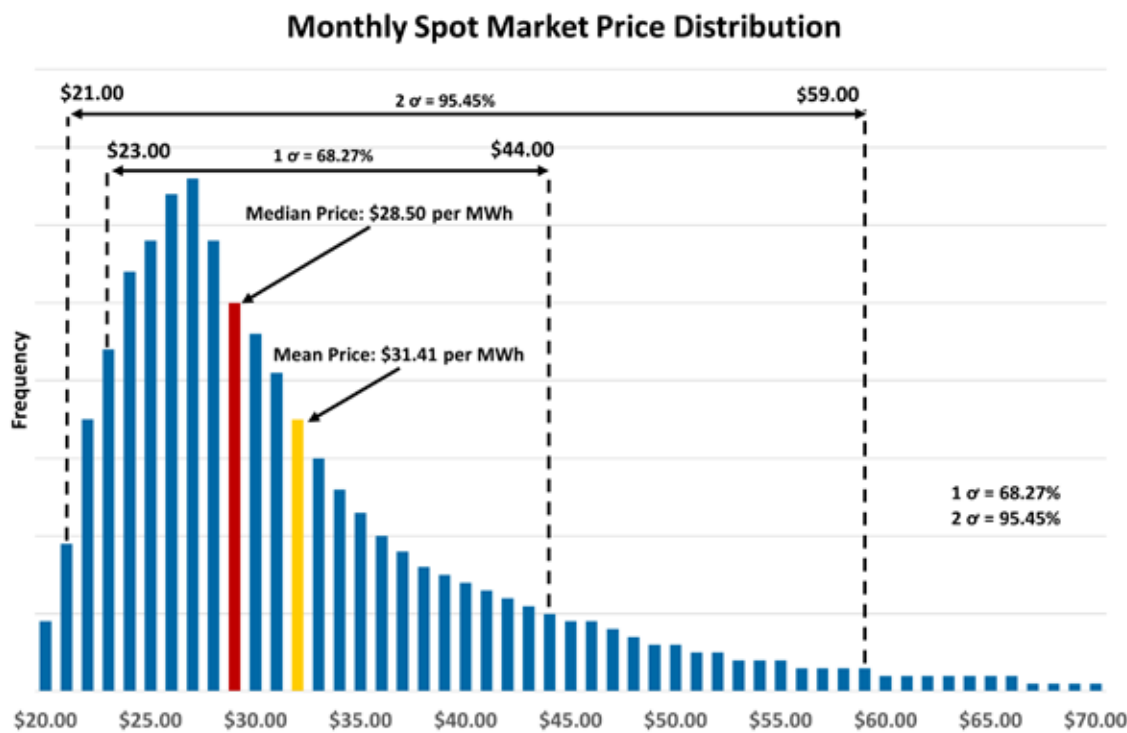


Figure 11.4-4: LGEE Monthly Spot Market Price Distribution



Forward Prices

Unlike spot prices which are immediate, forward prices are prices set today for future delivery. Because the forward prices set today may differ from the spot prices at the time of delivery, the value of a forward position will fluctuate over time. Accordingly, forward transactions require an explicit contract to bind both parties to the future terms.

The asymmetric probabilities around the futures price reflect the implication of a mathematical assumption underlying the Black-Scholes-Merton model. An intuitive explanation for the asymmetric probabilities is that the futures price reflects the need of traders to hedge. Traders not only care if the price rises or falls but also how much the price rises or falls. Traded prices can only fall to zero, but there is no theoretical upper limit to how far they can rise. The greater probability of a price below the mean is offset by the possibility of a price much higher than the mean.



11.5 Capacity and Scarcity Pricing

EnCompass forecasts annual capacity prices using the same methodology as the MISO auction, including the vertical demand curve. New capital projects and resources eligible for retirement will submit capacity bids to recover fixed operating and capital carrying costs, less any profits from the energy and ancillary service markets. If there are still unrecoverable costs, EnCompass will dynamically adjust energy and ancillary service bids using an operating reserve demand curve (ORDC) to match the RTO market rules.

MISO holds a voluntary annual capacity auction called a Planning Resource Auction (PRA). The PRA provides a way for MISO Market Participants to meet resource adequacy requirements. The PRA's location-specific approach encourages resources to take part in the zones where they provide the most benefit. Resource owners offer their generation and demand-side resources into the auction. Electric providers must secure enough resources to meet their Planning Reserve Margin Requirement (PRMR) either through self-supply, bilateral contracts, or through auction purchases.

For providers participating in the auction, MISO will clear resources from within each local resource zone, shown in Figure 11.5-1, based upon economic merit, until the zone's Local Clearing Requirement (LCR) has been reached. After the zone's LCR has been reached, MISO will continue to clear resources from both within and outside of the local zone based upon economic merit, until the zone's PRMR is reached. The auction clearing price is the price of the most expensive resource that clears in the auction. If there are insufficient resources to meet the zone's LCR or the zone's PRMR, the auction clearing price will be the Cost of New Entry (CONE), which is the cost of a new natural gas-fired combustion turbine facility in the zone.



Figure 11.5-1: MISO Local Resource Zone Map¹⁰⁴

104 RTO Insider. (n.d.). MISO Local Resource Zones [Digital image]. Retrieved April 27, 2021, from https://i1.wp.com/rtoinsider.com/wp-content/uploads/YfipbklyQQG1clfGYy-FK_full_Local-Resource-Zones-MISO-FI.jpg?resize=600%2C600&ssl=1



MISO Capacity Auction Offer Behavior

For PY2020/2021, 96.3% (131,003 MW) of the MISO PRA offer curve, which cleared the auction, was offered at a penny or less. The reason most of MISO market participants offer at a penny or less is because most of MISO states are not retail choice states.

As shown in Figure 11.5-2, of the ten MISO Local Resource Zones, only Zone 4, Illinois, is a 100% retail choice state. Zone 7, Michigan, permits 10% retail choice. The rest of the states consist of vertically integrated utilities with both supply and demand. The vertically integrated market participant is highly motivated to ensure their supply clears in the auction since their load must purchase from the auction. This leads to price offers of a penny or less as the utility's investment is recovered through regulated, retail rate making.

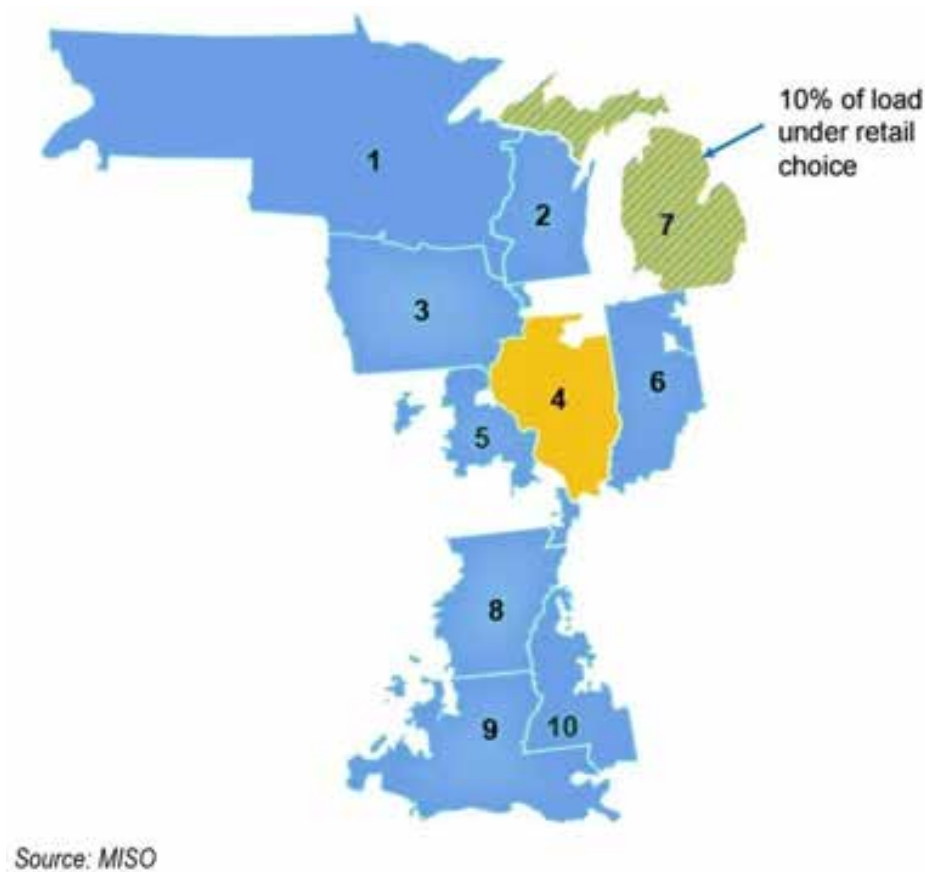


Figure 11.5-2: Retail Choice States in MISO¹⁰⁵

105 MISO. (n.d.). Retail Choice States in MISO [Digital image]. Retrieved April 27, 2021, from <https://rtoinsider.com/rto/miso-board-capacity-auction-imm-26870/>



MISO Independent Market Monitor PRA Recommendations

The MISO Independent Market Monitor (IMM), Potomac Economics, is tasked with evaluating the MISO capacity market design. In its recent 2019 State of the Market Report for the MISO Electricity Markets, Potomac states, “The demand for capacity in the PRA continues to poorly reflect the true reliability value of capacity and undermines the market’s ability to provide efficient economic signals.” As a remedy, the IMM has recommended MISO implement a sloped demand curve. “A sloped demand curve would produce more stable and predictable pricing, which would increase the capacity market’s effectiveness in providing incentives to govern investment and retirement decisions. A sloped demand curve also reduces the incentive to exercise market power because a market with a vertical demand curve is highly sensitive to withholding. Clearing at the deficiency level creates a strong incentive for suppliers to withhold resources to raise prices. Withholding in such a market is nearly costless because the foregone capacity sales would otherwise be priced at close to zero. The benefits of a sloped demand curve will increase as planning reserve margins fall as competitive resources continue to retire.”

MISO Supply and Demand in 2020/2021 PRA

Figure 11.5-3 illustrates how a sloped demand curve applied to the MISO 2020/2021 PRA would significantly raise auction prices.

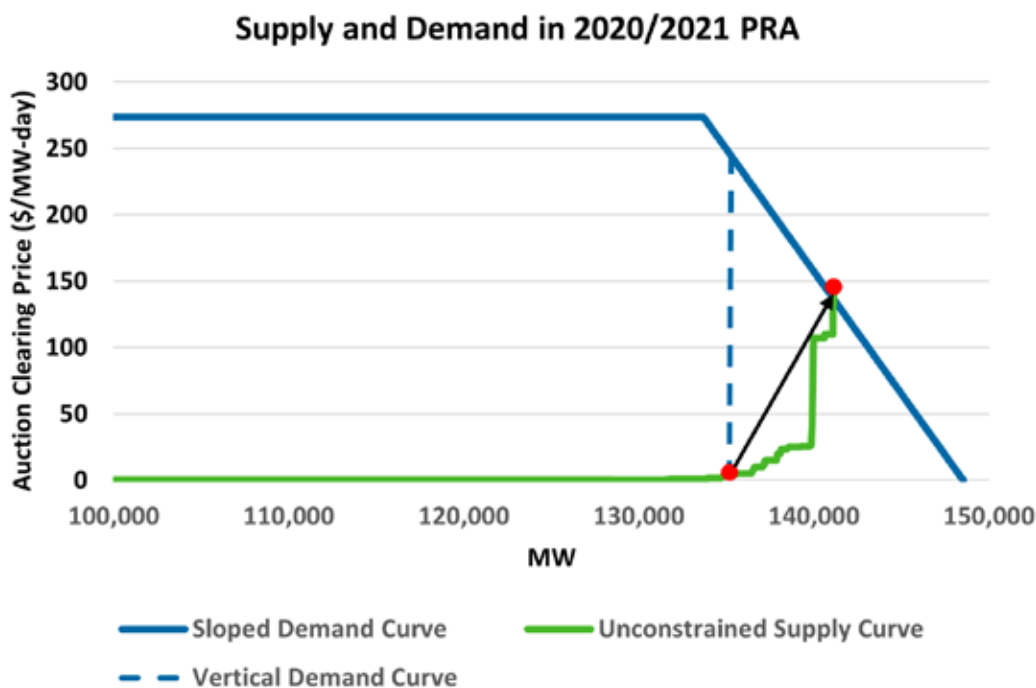


Figure 11.5-3: Potomac Economics Proposed MISO Sloped Demand Curve¹⁰⁶

While the KYMEA load is not in MISO, the Agency monitors the MISO capacity market developments as the MISO resource mix and reserve balance directly affect KYMEA’s bilateral capacity market opportunities. When forecasting the bilateral capacity prices with EnCompass for Integrated Resource Planning, KYMEA uses a rational approach where capacity resources recover their investment. As it is clear from the IMM recommendations, the IMM does not feel the current MISO PRA is sustainable in the future.

¹⁰⁶ 2019 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS (Rep.). (2020, June). Retrieved April 27, 2021, from Potomac Economics website: https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-MISO-SOM_Report_Final_6-16-20r1.pdf



MISO Operating Reserve Demand Curve (ORDC)

In its recent 2019 State of the Market Report for the MISO Electricity Markets, the Independent Market Monitor (IMM) provided a recommendation for the ORDC. As was mentioned earlier in this report, electricity prices exhibit jumps in price. In the MISO market, the jumps are bound by an ORDC cap.

The IMM, Potomac Economics, states, “Virtually all shortages in (co-optimized) energy and ancillary markets are of reserve products (i.e., RTOs will hold less reserves than required rather than not serving the energy demand). When an RTO is short of reserves, the value of the foregone reserves should set the reserve market clearing price and be embedded in all higher-value products, including energy. This value is established in the reserve demand curve for each reserve product, so efficient shortage pricing requires properly valued reserve demand curves.”

“Efficient shortage prices play a key role in establishing economic signals to guide investment and retirement decisions in the long-term, facilitating optimal interchange and generator commitments in the short-run, and efficiently compensating flexible resources. Compensating flexible resources efficiently will be increasingly important as the penetration of renewable resources increases. The output of most renewable resources is intermittent and increases supply uncertainty, which will likely increase the frequency of reserve shortages.”

The IMM recommended that MISO improve its shortage pricing by improving its net value of lost load (VOLL) and the slope of its ORDC as shown in Figure 11.5-4. The IMM recommended MISO adopt a VOLL of \$10,000 per MWh.

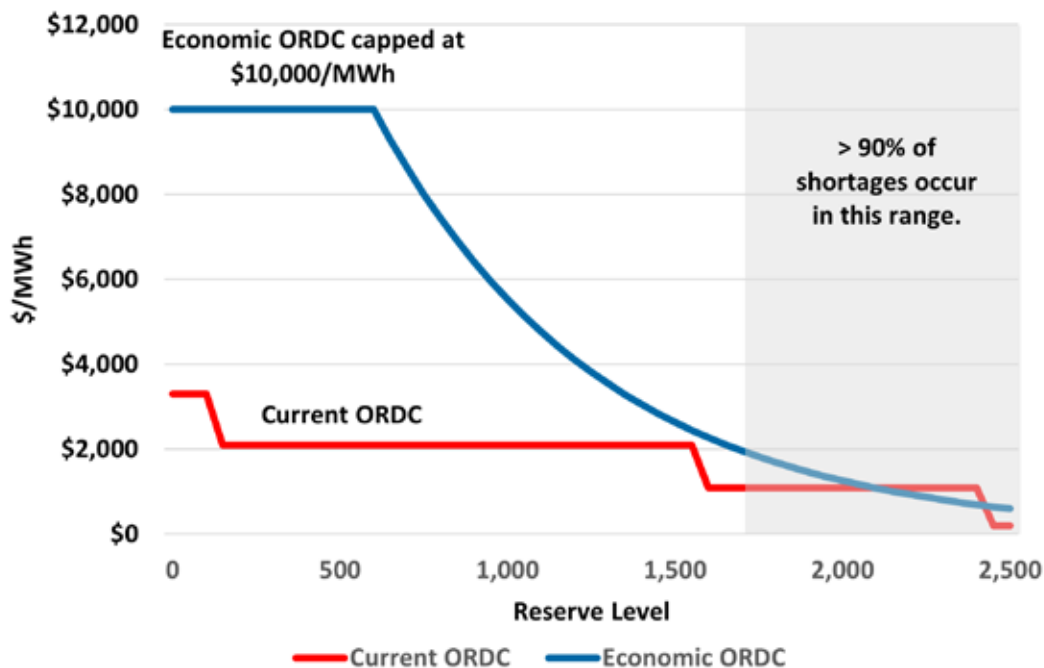


Figure 11.5-4: Potomac Economics Proposed Economic ORDC¹⁰⁷

The Horizons Energy national database models the current MISO ORDC levels. KYMEA monitors the MISO ORDC developments as changes in the VOLL can have a significant impact on the Agency’s energy purchases from the MISO market.

107 2019 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS (Rep.). (2020, June). Retrieved April 27, 2021, from Potomac Economics website: https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-MISO-SOM_Report_Final_6-16-20r1.pdf



11.6 Natural Gas Markets

In Section 10, Scenario Development, Horizons Energy created unique daily natural gas price forecasts that correspond to the nine scenarios. For each scenario, there is a Henry Hub forecast plus a forecast for 43 additional price points identified on the map in Figure 11.6-1.

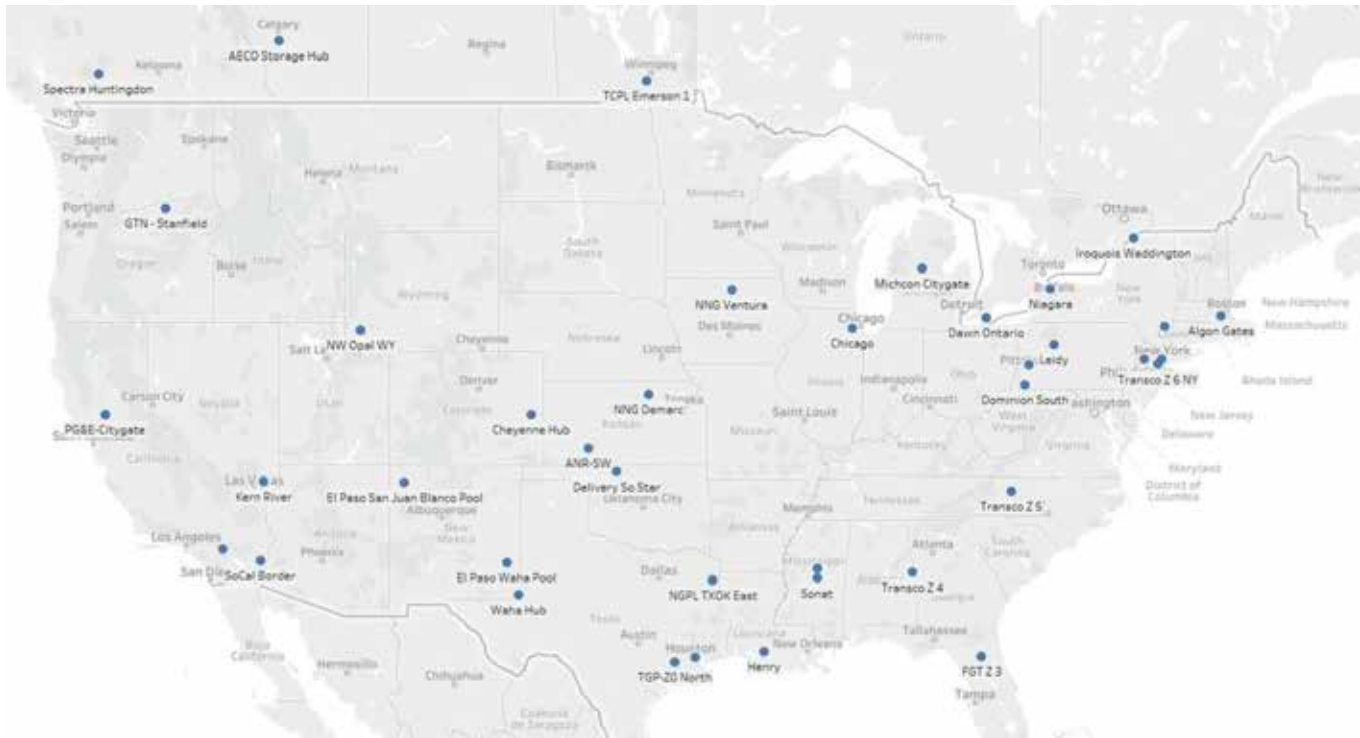


Figure 11.6-1: Natural Gas Market Centers - Horizons Energy

Each natural gas generating resource in the Horizons Energy NDB is mapped to one of the price points. The burner-tip gas price for each gas-fired generation plant in a region is developed by taking the hub price and adding a regional transportation adder. This amount depends on the plant's location relative to the basins or hubs and the economics of transporting gas, including compressor fuel used and pipeline tariffs/discounts, to the plant's burner-tip. The commodity and transportation components of natural gas burner-tip prices are forecast separately and then assembled to derive the prices paid by generation plants appropriate to their geographic location.



President Biden Executive Order - Climate Crisis

On January 27, 2021, President Biden issued Executive Order 14008—Tackling the Climate Crisis at Home and Abroad—to "pursue action at home and abroad in order to avoid the most catastrophic impacts of that crisis and to seize the opportunity that tackling climate change presents."

The order directs the Secretary of the Interior to "pause new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices," including "potential climate and other impacts associated with oil and gas activities on public lands or offshore waters."

This expands upon the 60-day moratorium on new oil and gas leasing or drilling permits on federal land Biden enacted January 20, 2021. It remains unclear if President Biden will pursue a permanent ban on fracking on federal lands after the 60-day moratorium ends.

Figure 11.6-3 highlights the location of federal lands. About 11% of all hydraulic fracturing occurs on federal land. The balance occurs on private and state-owned land. States have jurisdiction on private and state-owned land where the vast majority of fracking is done.

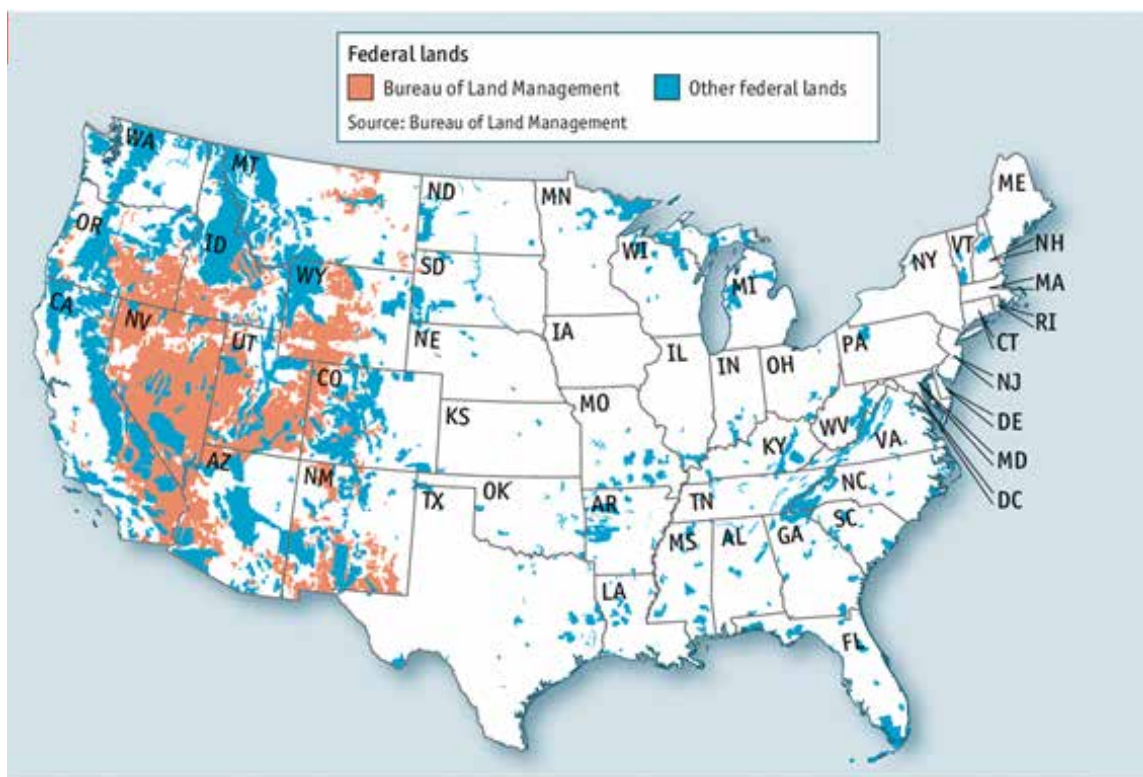


Figure 11.6-3: Federal Lands¹⁰⁹

109 The Economist. (2014, April 26). Federal Lands [Digital image]. Retrieved April 27, 2021, from <https://www.economist.com/united-states/2014/04/24/cowboys-v-feds>



Liquefied Natural Gas

Liquefied natural gas (LNG) is natural gas that has been cooled to a liquid state (liquefied), at about -260° Fahrenheit, for shipping and storage. The volume of natural gas in its liquid state is about 600 times smaller than its volume in its gaseous state in a natural gas pipeline. This liquefaction process makes it possible to transport natural gas to places natural gas pipelines do not reach and to use natural gas as a transportation fuel.

The United States was a net exporter of LNG in 2017 through 2019 (exports were greater than imports), largely because of increases in U.S. natural gas production, declines in natural gas imports by pipeline and as LNG, and increases in LNG export terminal capacity.

U.S. LNG export capacity increased from less than 1 billion cubic feet per day (Bcf/d) in 2016 to nearly 9 Bcf/d at the end of 2019. In 2015, total U.S. LNG exports were about 28 Bcf to seven countries. In 2019, U.S. LNG exports reached a record high of about 1,819 Bcf to 38 countries, and LNG exports accounted for 39% of total U.S. natural gas exports. About half of LNG exports went to five countries in 2019. Figure 11.6-4 identifies the LNG export facilities and their output.

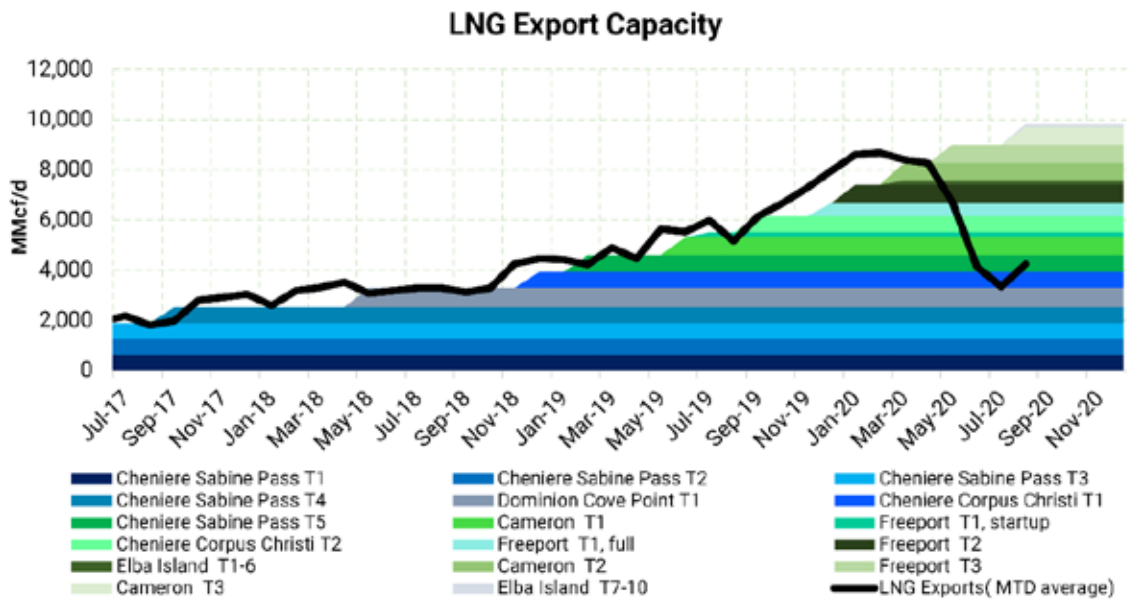


Figure 11.6-4: LNG Export Capacity¹¹⁰

¹¹⁰ AEGIS Hedging Solutions, LLC. (n.d.). LNG Export Capacity [Digital image]. Retrieved April 27, 2021, from <https://aegis-hedging.com/insights/u-s-lng-export-capacity-continues-to-grow/>



Figure 11.6-5 shows U.S. LNG exports dropped in 2020 due to a drop in demand resulting from the response to the COVID-19 pandemic.

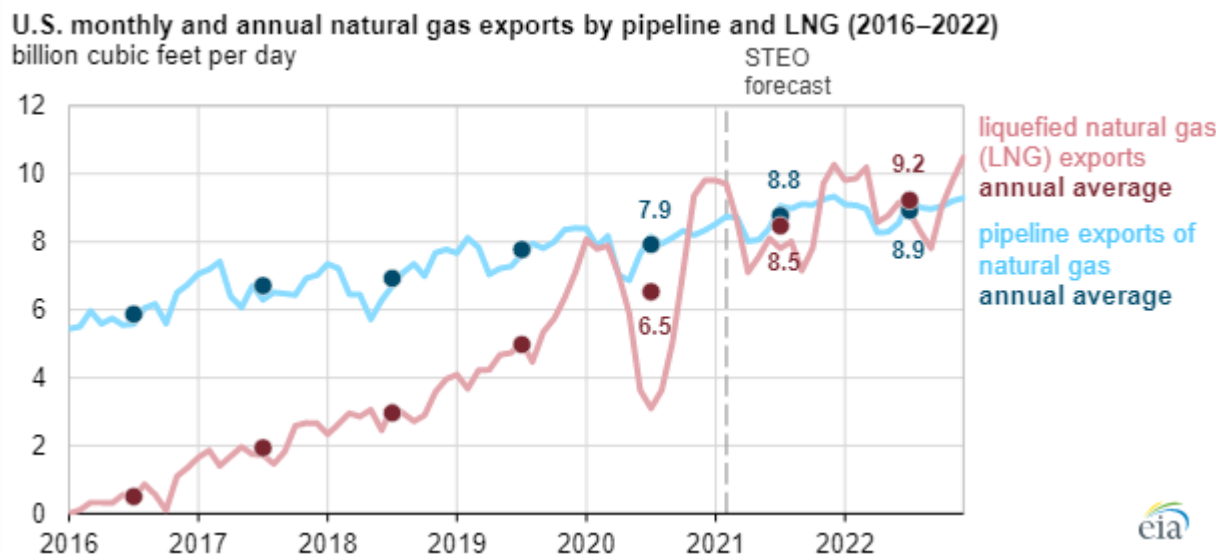


Figure 11.6-5: U.S. Monthly and Annual Gas Exports by Pipeline and LNG (2016-2022)¹¹¹

¹¹¹ EIA. (2021, February 18). Annual U.S. liquefied natural gas exports forecast to exceed pipeline exports in 2022. Retrieved April 27, 2021, from <https://www.eia.gov/todayinenergy/detail.php?id=46796>



11.7 Coal Markets

Forecasted prices for coal at the mine (or FOB mine) are driven by producer cost, generator demand, and competition among all of the mines that can provide coal to a given generating unit, subject to constraints which include environmental, unit specific coal quality and handling, and transportation.

Since 2008, coal retirements have increased at a rapid pace with no signs of relenting. Low natural gas prices, tightened emission regulations, an aging coal fleet, and a push towards renewable energy will ultimately remove most, if not all, coal generation over the next three decades if not sooner.

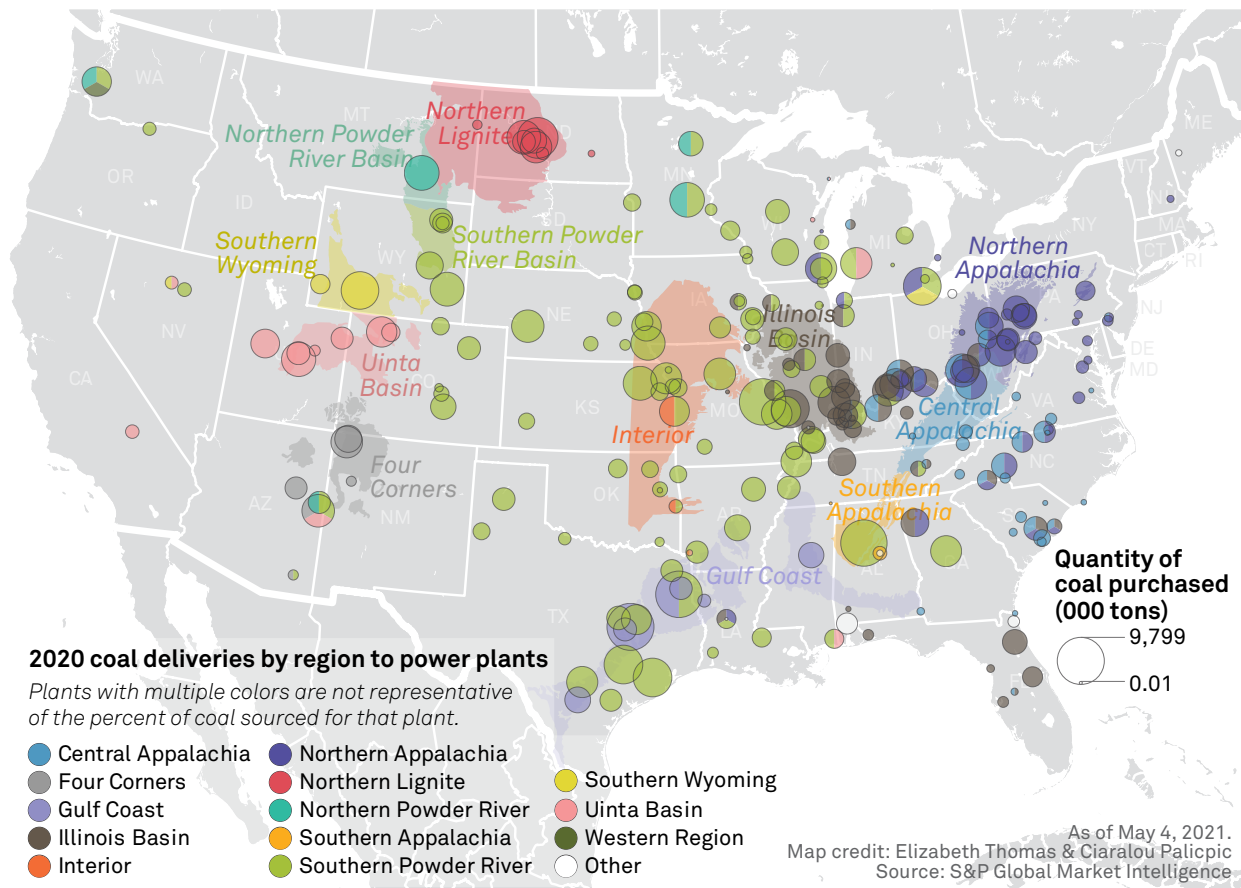


Figure 11.7-1: Deliveries from Major Coal Basins¹¹²

The Horizons Energy forecast is by coal basin. Coal is delivered from the coal basins to each power plant by rail, barge, or truck. Powder River Basin coal, which is abundant, easy to mine, cheap, and low in sulfur content, is the most widely used coal, as illustrated in Figure 11.7-2.



MISO Energy Mix

While the mix of coal in MISO continues to decline, coal remains the dominant fuel source in MISO Central. As shown in the Figure 11.7-2, MISO Central (Indiana, Kentucky, Illinois, Missouri, Wisconsin, and Michigan) was 55% coal in 2019. Given a large percentage of KYMEA's energy is sourced from MISO, it is important the Agency have a clear understanding of the MISO coal price projections and future resource mix.

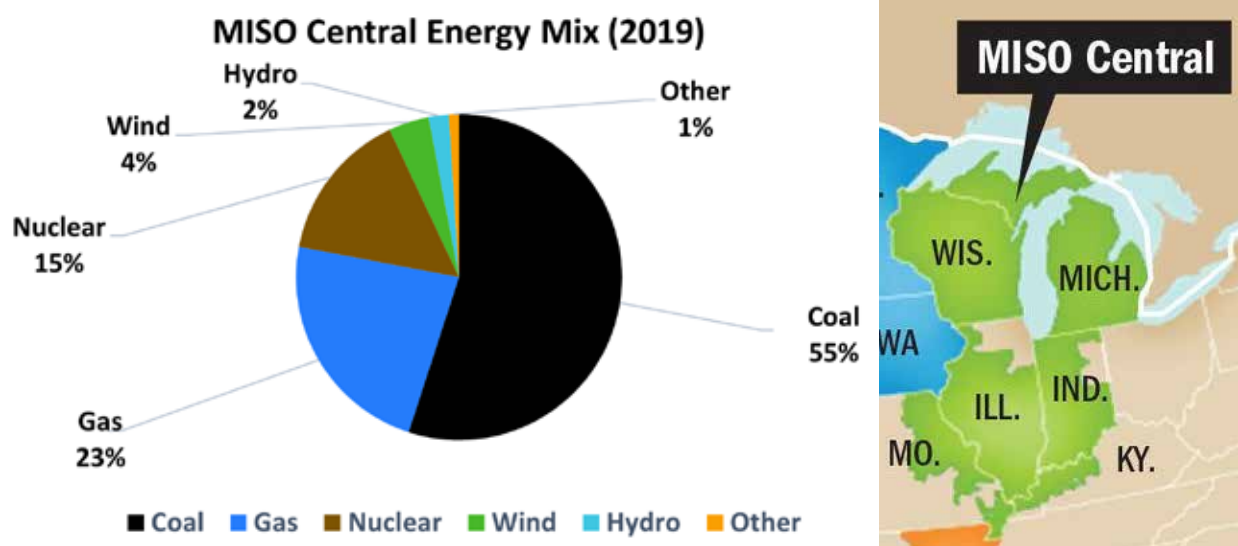
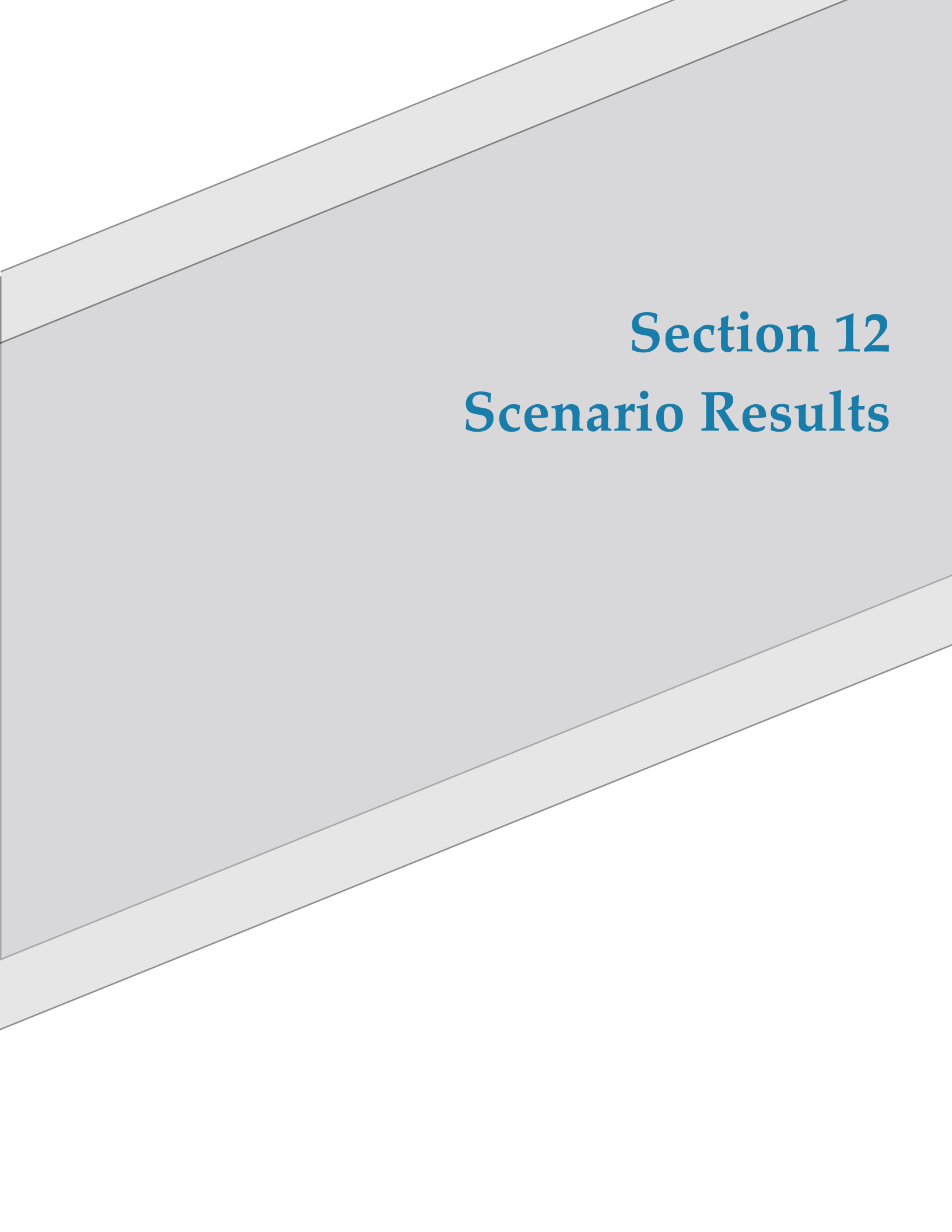


Figure 11.7-2: MISO Central 2019 Energy Mix - MISO

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Section 12

Scenario Results

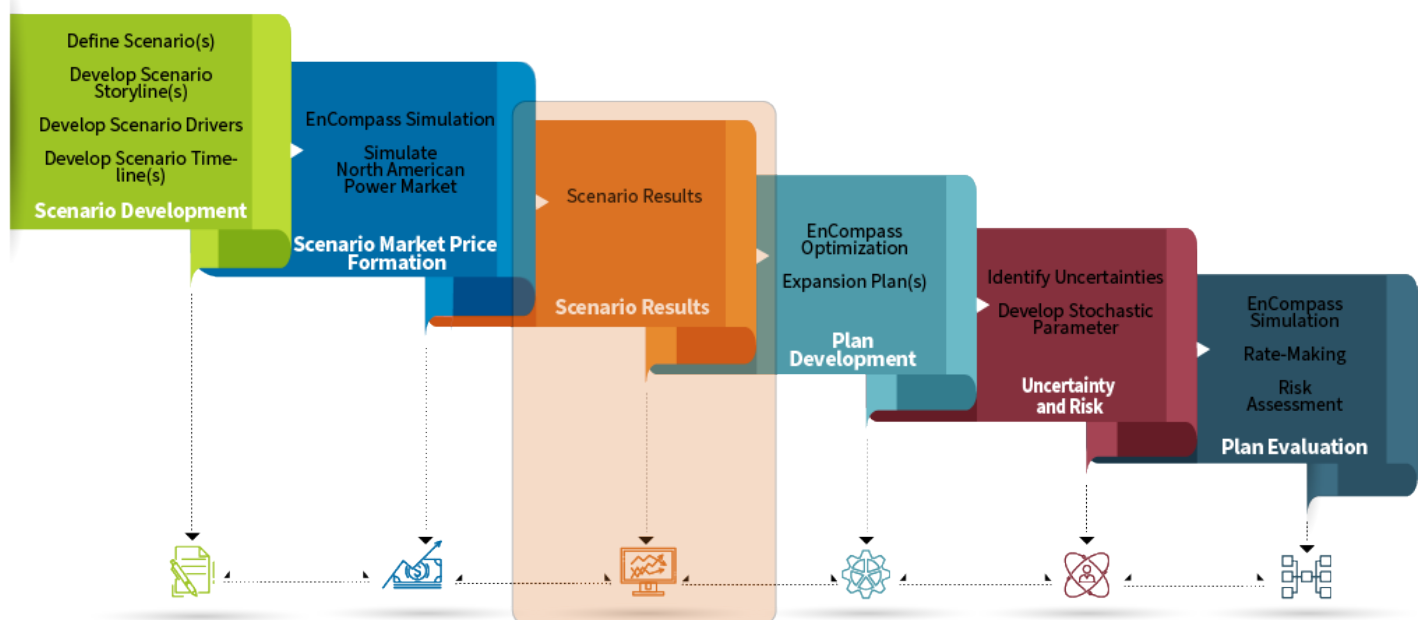
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12. SCENARIO RESULTS

An EnCompass market model simulation is performed for each of the nine scenarios identified in Section 10, providing unique attributes associated with each probable future. In essence, an entire North American power grid integrated resource plan (IRP) is conducted for each of the nine scenarios. The market model results are analyzed to ensure they provide reasonable “book-ends” that examine plausible alternative views of the future given different economic, regulatory, and technological driving forces.

IRP FLOWCHART





12.1 Resource Mix

For each of the nine scenarios, an energy mix graph was created for the years 2000 to 2042 (43 years).

Power Sector Energy Mix Figures

The following figures illustrate the North American generation energy mix for the nine Horizons Energy scenarios.

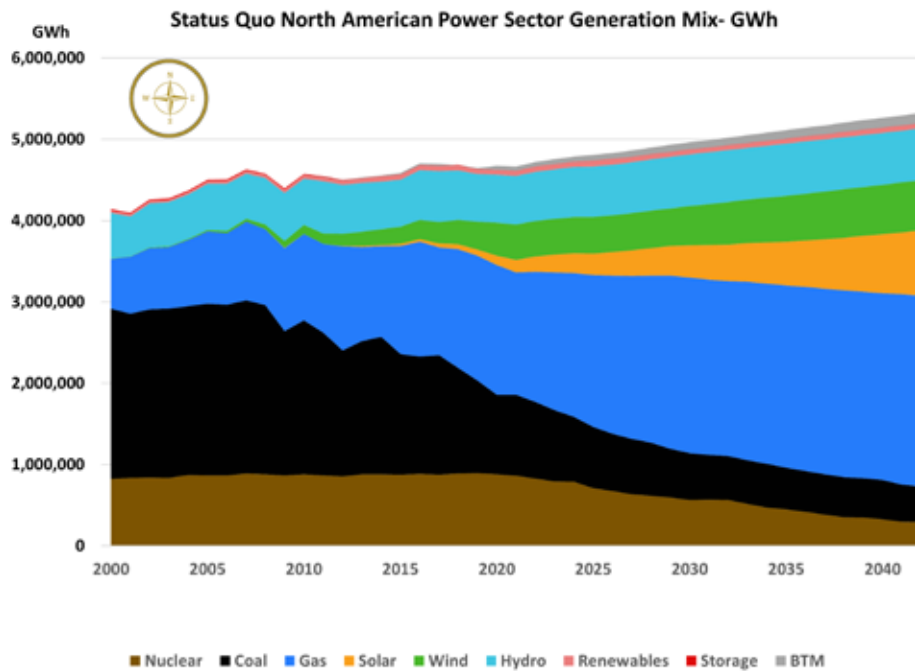


Figure 12.1-1: Status Quo - North American Power Sector Mix (GWh)

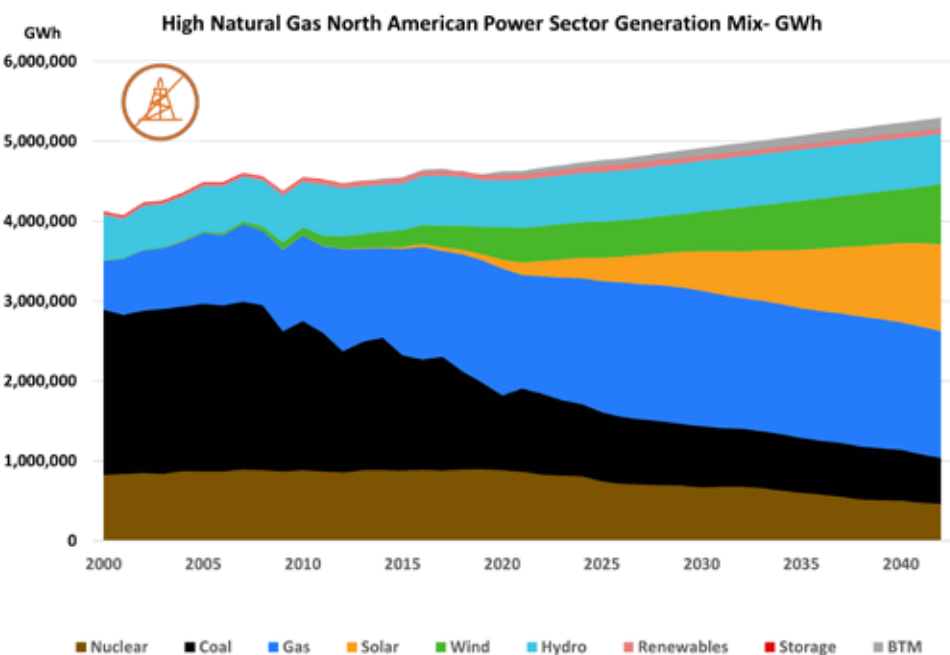


Figure 12.1-2: High Natural Gas - North American Power Sector Mix (GWh)

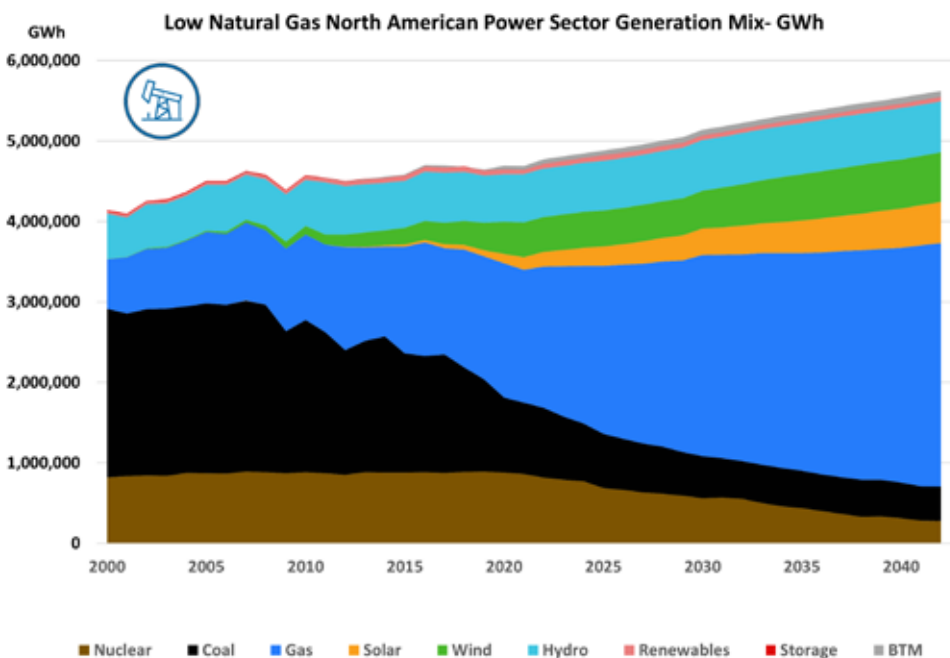


Figure 12.1-3: Low Natural Gas - North American Power Sector Mix (GWh)

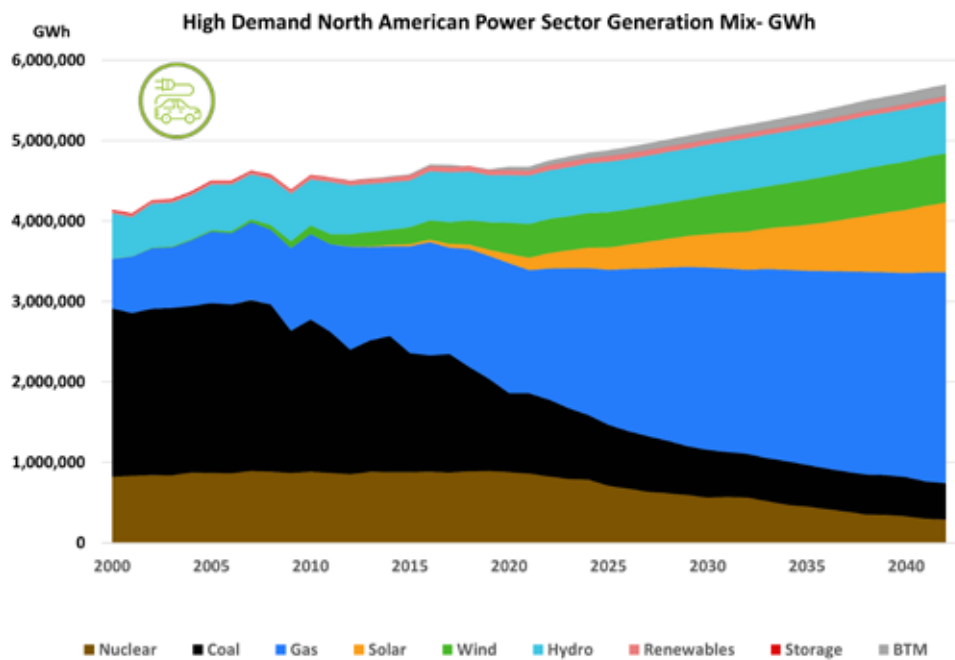


Figure 12:1-4: High Demand - North American Power Sector Mix (GWh)

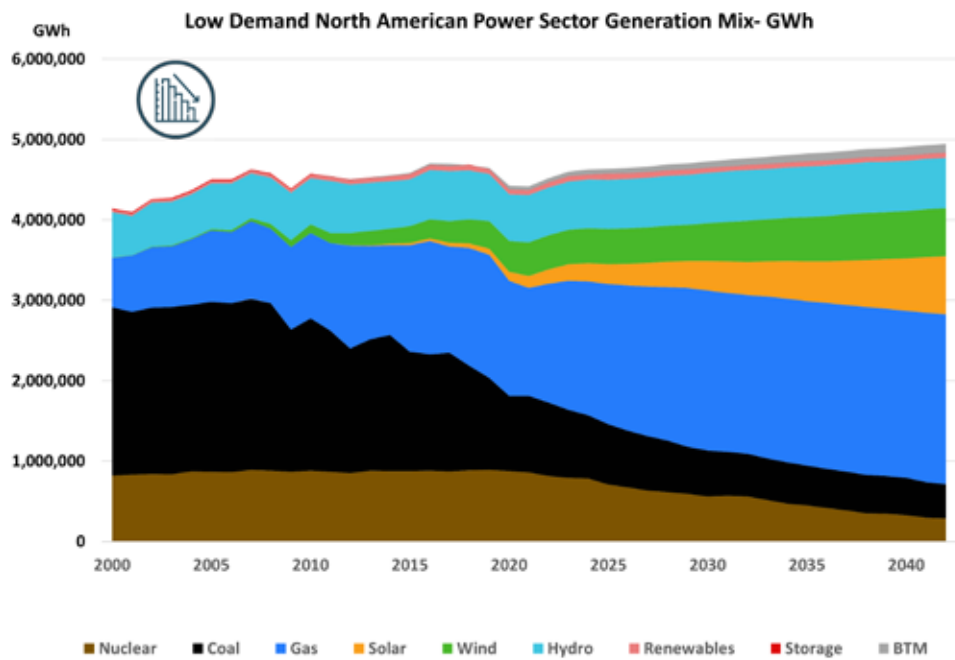


Figure 12:1-5: Low Demand - North American Power Sector Mix (GWh)

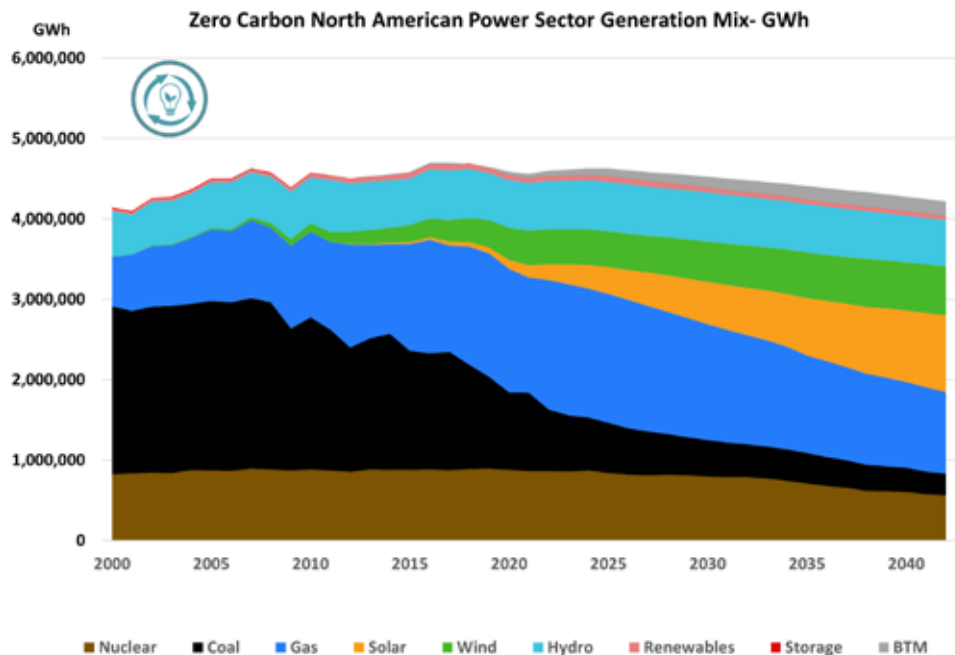


Figure 12:1-6: Zero Carbon - North American Power Sector Mix (GWh)

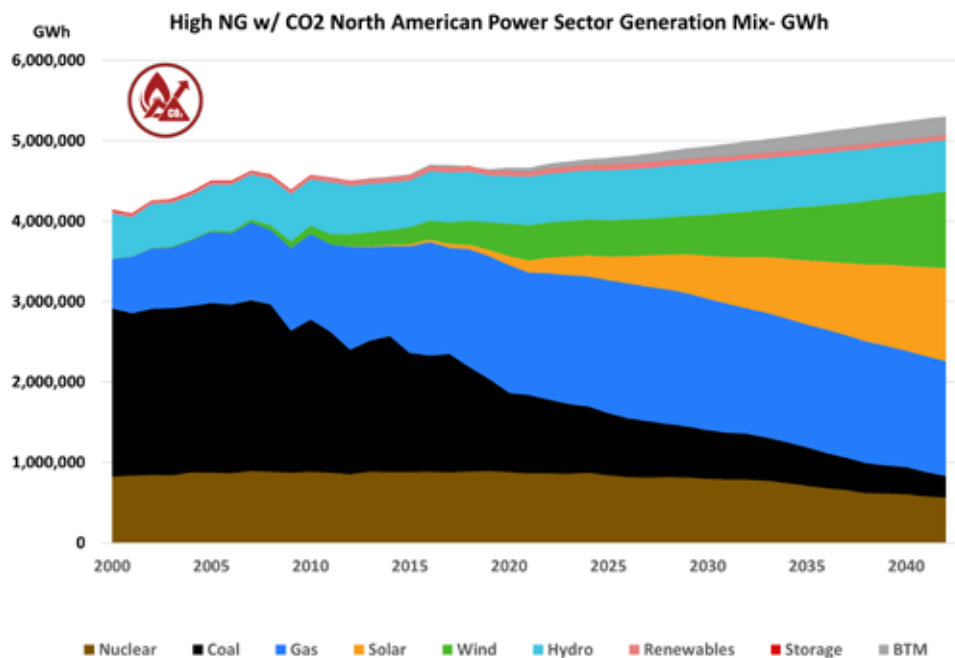


Figure 12:1-7: High Natural Gas with CO2 - North American Power Sector Mix (GWh)

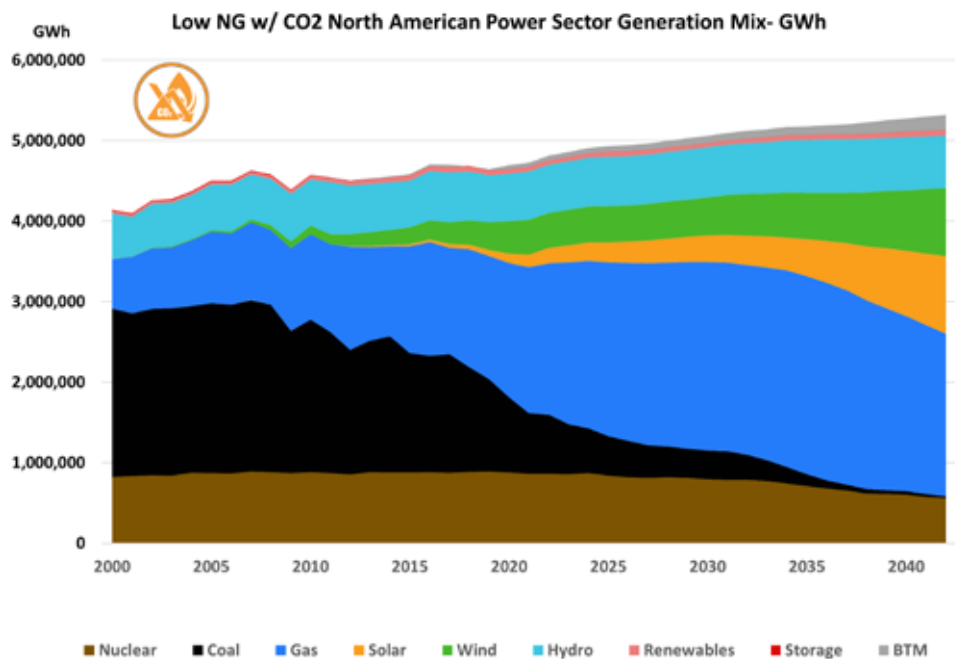


Figure 12:1-8: Low Natural Gas with CO2 - North American Power Sector Mix (GWh)

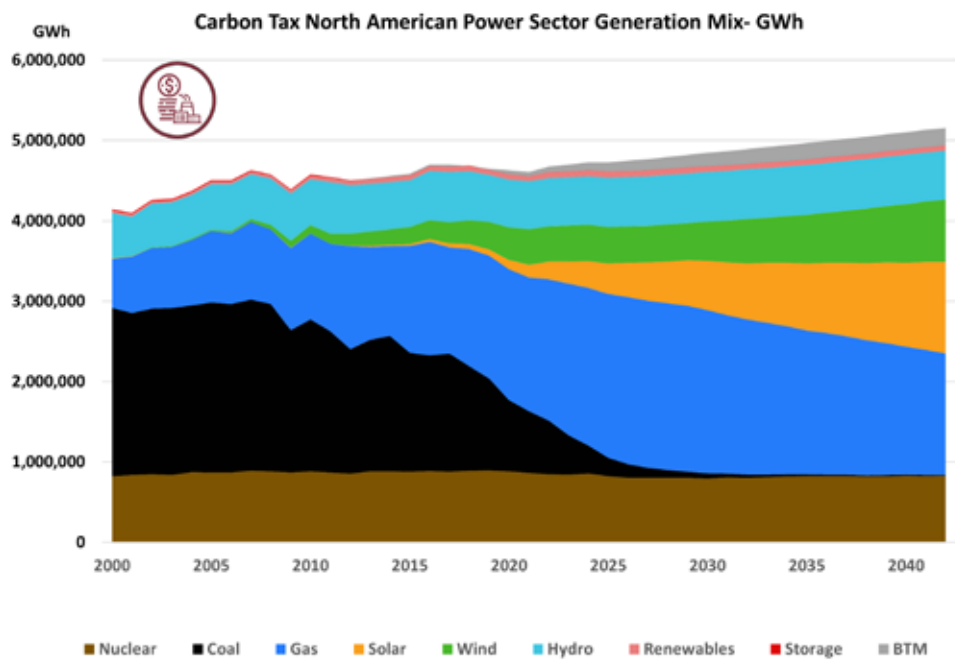


Figure 12:1-9: Carbon Tax - North American Power Sector Mix (GWh)



Nine Scenarios - Energy Mix (2042)

When comparing the last year of the study (2042), the North American energy mix across the nine scenarios varies greatly. Overall, the energy mix from the traditional base load resources of nuclear and coal swings from a low of 8% (Low Natural Gas Scenario) to a high of 20% (High Natural Gas Scenario). Given in 2020, the combined nuclear plus coal was 39%; all nine scenarios show a significant reduction over the next 20 years.

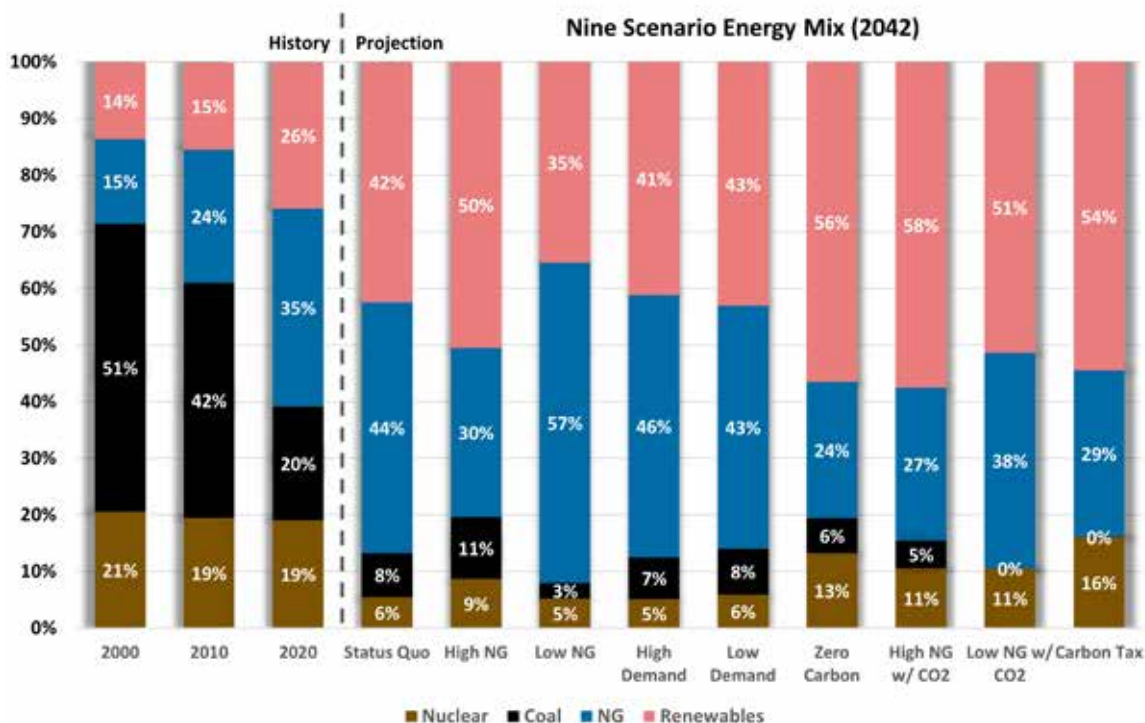


Figure 12.1-10: Nine Scenarios - North American Energy Mix (2042)



12.2 Power Sector Fuel Consumption

Natural Gas Power Sector Consumption

In the Low Natural Gas scenario, natural gas burn increases 70% from 2020 to 2042. Conversely, in the Zero Carbon Additions scenario, natural gas burn decreases 36% from 2020 to 2042. In the Status Quo scenario, natural gas burn increases to 13 TCF by 2035 and stabilizes at that level. Shown in Figure 12.2-1, the Low Natural Gas with Carbon Limit scenario illustrates how the carbon limit stifles natural gas consumption.

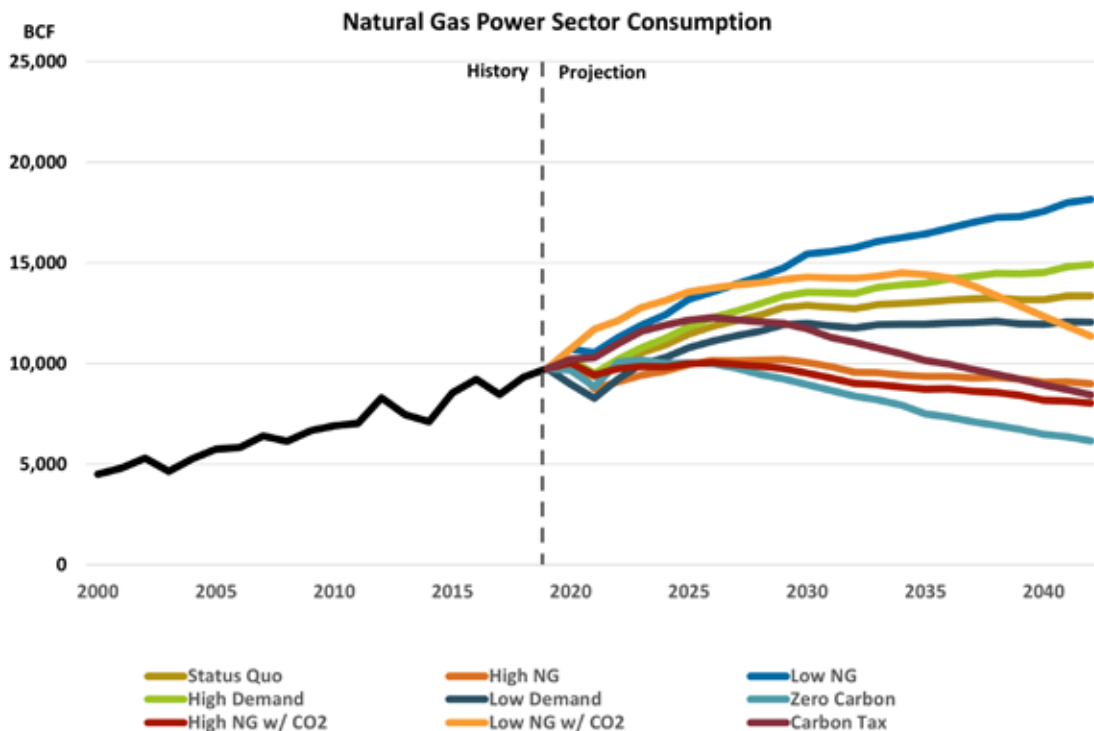


Figure 12.2-1: Natural Gas Power Sector Consumption

Role of Natural Gas

The scenarios create trade-offs between natural gas and renewable energy. Natural gas has been described as either:

1. The nation's next base resource as natural gas is cleaner and cheaper than coal, or
2. A "bridge" to renewable energy in a measured transition away from fossil fuels by the year 2050

Recently, environmentalists who were previously championing natural gas as a bridge, are advocating to bypass natural gas altogether and transition directly to renewables. None of the nine Scenarios eliminates fossil fuels, although the Zero Carbon and High Natural Gas with CO₂ Limits reduce the fossil fuel mix to around 37%.



Coal Power Sector Consumption

In the High Natural Gas scenario, coal consumption hovers around 250 million tons. In the CO₂ Limit with Low NG scenario, coal is eliminated by 2036. In the CO₂ Tax scenario, coal is eliminated by 2031. Due to its low cost, Southern Powder River Basin (SPRB) coal is the strongest performer; however, it too sees a sharp decline across all nine scenarios.

The reduction in coal consumption, shown in Figure 12.2-2, will continue to have a significant impact on the rail industry. Coal accounts for 30.1% of originated tonnage for U.S. railroads and 12.7% of their revenue, far more than any other commodity.

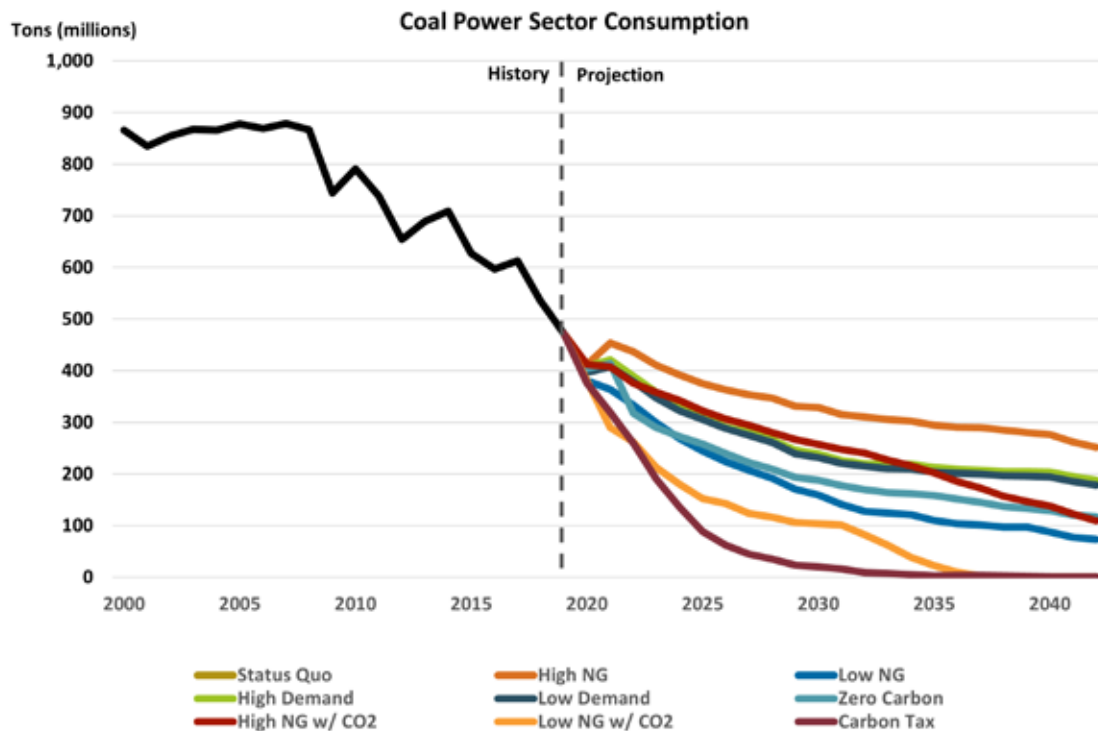


Figure 12.2-2: Coal Power Sector Consumption



12.3 Carbon

Status Quo Power Sector CO₂ Emission Trajectory

As illustrated in Figure 12.3-1, in the Status Quo scenario, U.S. power sector CO₂ emissions is reduced to 44% below 2005 levels by 2030. Over the last decade, the power industry has closely observed the ebb and flow of carbon policies and rulemaking that have been enacted, repealed, and reenacted across three administrations.

Recent Carbon Policies and Rules

- June 2, 2014 - EPA proposed the Clean Power Plan (CPP) for cutting carbon pollution from existing power plants. (Obama)
- December 12, 2015 - the U.S. entered into the Paris Climate Agreement. (Obama)
- June 19, 2019 - the EPA issued the final Affordable Clean Energy rule (ACE) replacing the CPP. (Trump)
- November 4, 2020 - the U.S. withdrew from the Paris Climate Agreement. (Trump)
- January 19, 2021 - the United States Court of Appeals for the District of Columbia Circuit (the “DC Circuit”) vacated the ACE Rule.
- February 18, 2021 - the U.S. rejoined the Paris Climate Agreement. (Biden)



The Status Quo scenario assumes there is not a national policy limiting power sector carbon emissions; however, it is important to note that the 44% decrease below 2005 levels by 2030 far exceeds President Obama's CPP target, which called for a 32% reduction by 2030. The expected 2030 Status Quo decrease is driven by fuel-switching from coal generation (12% of the energy mix) to combined cycle natural gas (45%), wind (10%), and solar (9%).

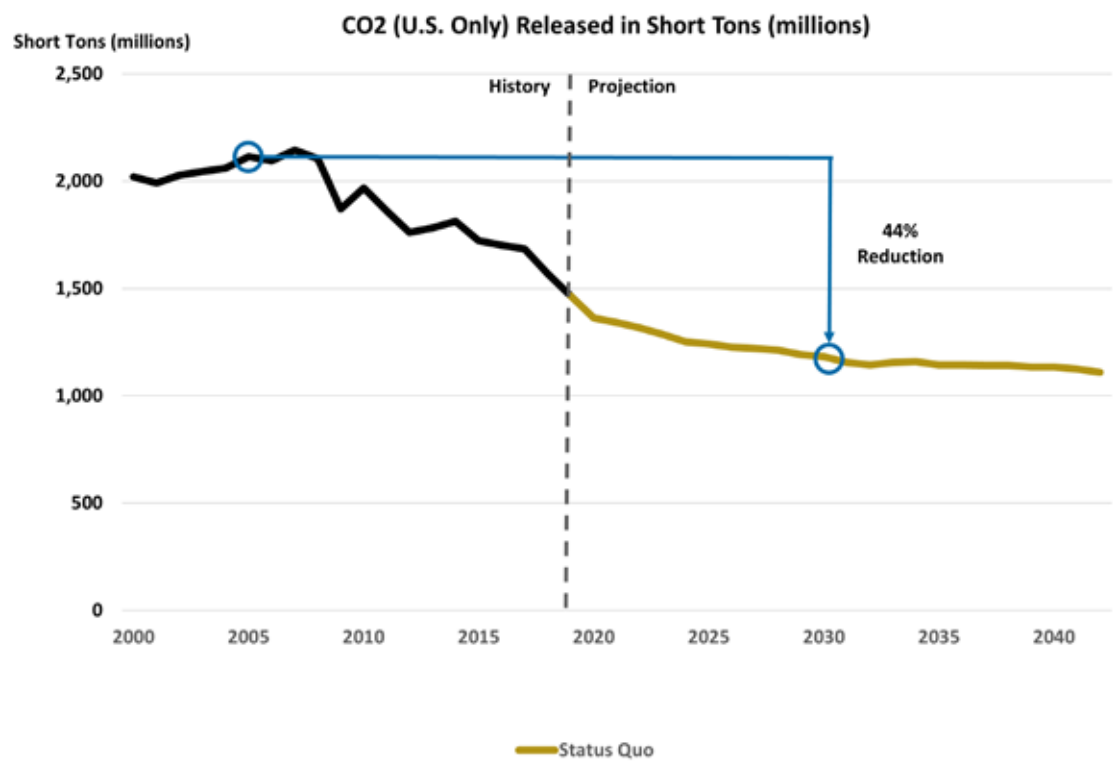


Figure 12.3-1: Status Quo - U.S. Power Sector CO2 Emissions (MM short tons)



In the Status Quo scenario, it is expected the U.S. Power Sector carbon intensity will drop to 554 lb/MWh by 2030 (49%) and 484 lb/MWh by 2042 (55%) below the 2005 level, as illustrated in Figure 12.3-2.

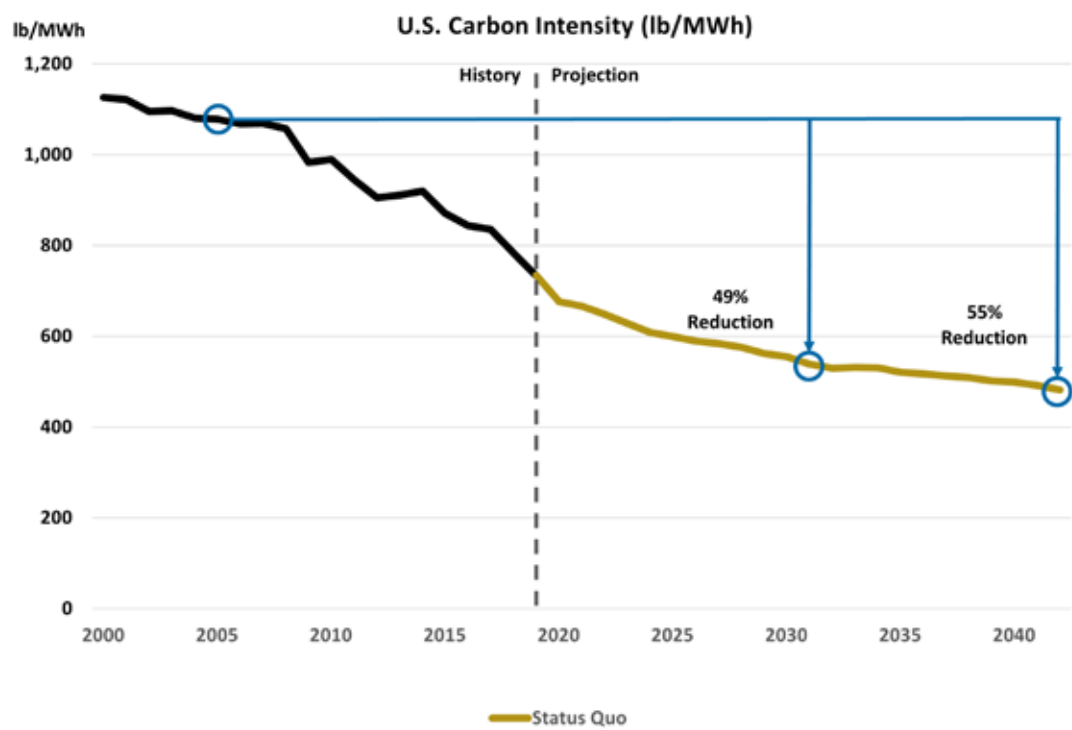


Figure 12.3-2: Status Quo - Power Sector Carbon Intensity (lb/MWh)



No Carbon Emission Limit Scenario Trajectories

In the five No Carbon Emission Limit scenarios (Status Quo, High Natural Gas, Low Natural Gas, High Demand, and Low Demand), U.S. CO2 emissions are projected to decrease in the range of 43% to 53% below 2005 levels by 2042. In these scenarios shown in Figure 12.3-3, the released CO2 power sector emissions remain relatively constant, with a slight decline over time. As with the Status Quo scenario, the reduction is driven by fuel-switching from coal generation to combined cycle natural gas, wind, and solar.

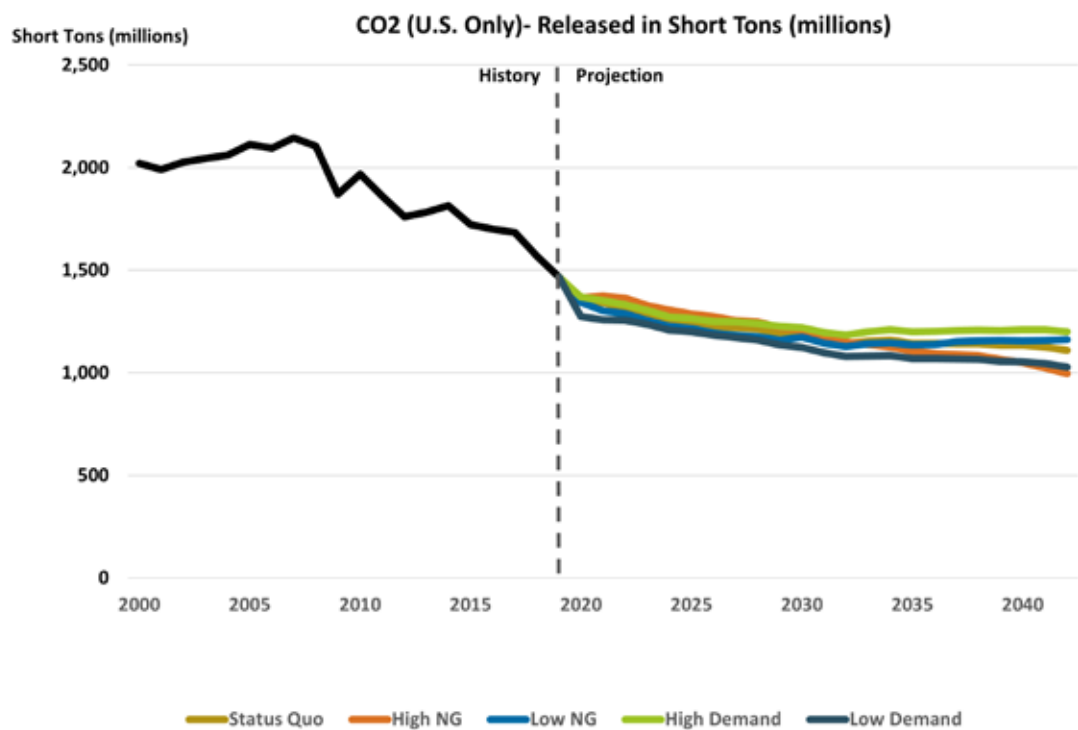


Figure 12.3-3: No Carbon Limit - U.S. Power Sector CO2 Emissions (MM short tons)



Role of Nuclear Generation

Nuclear generation is undergoing a tug-of-war decision between relicensing or retiring. Providing grid resiliency and contributing towards zero carbon emissions are positive attributes for nuclear generation; however, nuclear energy is finding it difficult to compete economically with low priced natural gas and zero marginal cost renewable energy.

By 2022, there are expected to be 114 operating nuclear power plants located in North America. The newest will be Vogtle 3 and 4, assuming their construction and start-up is successfully completed by 2022. The other “newer units” are TVA’s Watts Bar 2 (which began construction in 1985, had construction suspended 22 years until 2007, and was completed and brought online in 2016), and Bruce Power units A1 and A2 in Ontario, where 1977 vintage plants were shut down in the mid-1990s after which the units were refurbished and restarted in 2012.

The median age of the 114 plants will be 40 years in 2022. Since a nuclear license is granted for 40 years, a median age of 40 years presents the decision of relicensing or retiring. As evidenced by Figure 12.3-4, there is expected to be a rapid decline in nuclear generation as many plants are expected to be retired rather than apply for a 20-year license extension. In a world transitioning towards decarbonization, the loss of 60-65% of the nuclear generation means a significant carbon-free source of generation must be replaced. To replace 69 GW of nuclear generation is equivalent to 250 GW of solar or 155 GW of wind.

Figure 12.3-4 highlights the five scenarios, which do not have a carbon limit policy or a carbon tax. Of these five scenarios, nuclear generation, under the High Natural Gas scenario declines the least.

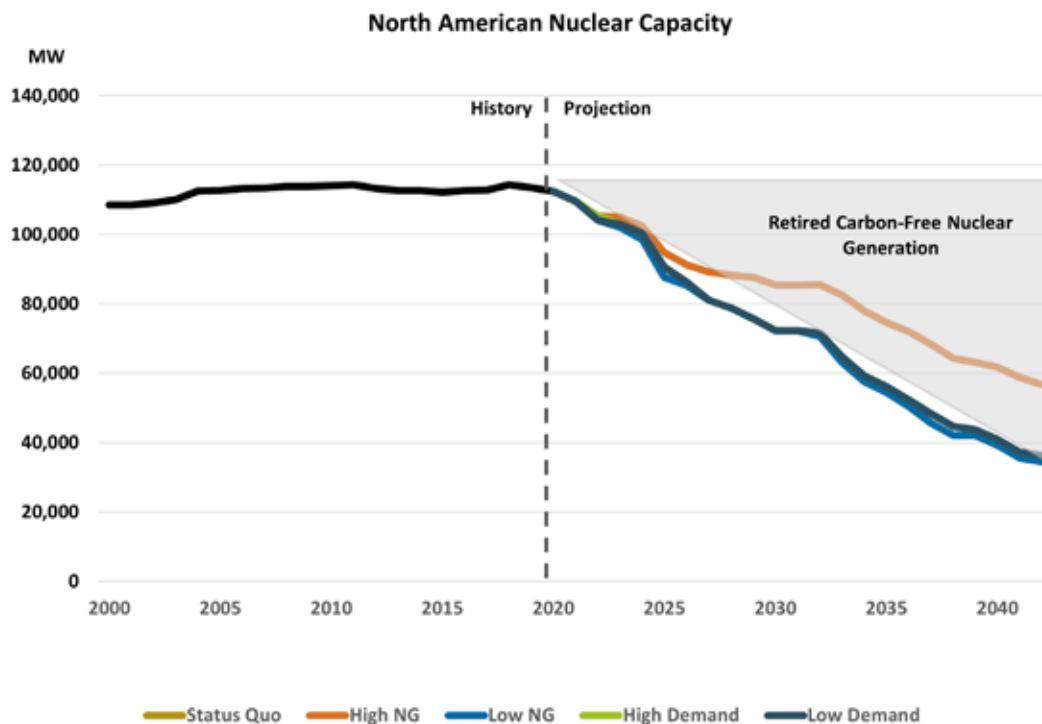


Figure 12.3-4: Nuclear Retirements - Impact on Carbon-Free Generation



Carbon Price

To determine the value, or price, of carbon emissions for scenarios that impose a carbon limit, EnCompass calculates the shadow price required to achieve the limit. Shadow pricing is a method of investment or decision analysis that adds a hypothetical surcharge to market prices for goods or services that involve significant carbon emissions in their supply chain.

- **The High Natural Gas with Carbon Limit** scenario imposes a carbon limit consistent with the Paris Climate Accord. In Figure 12.3-5, the gray line shows the carbon limit, the orange line shows the High Natural Gas scenario carbon emissions without a limit, and the red line shows the carbon emissions with a limit. The 2nd Y-axis, black line, is the calculated shadow price of achieving the limit. The shadow price is applied as a carbon cost to KYMEA portfolios when analyzing this scenario.

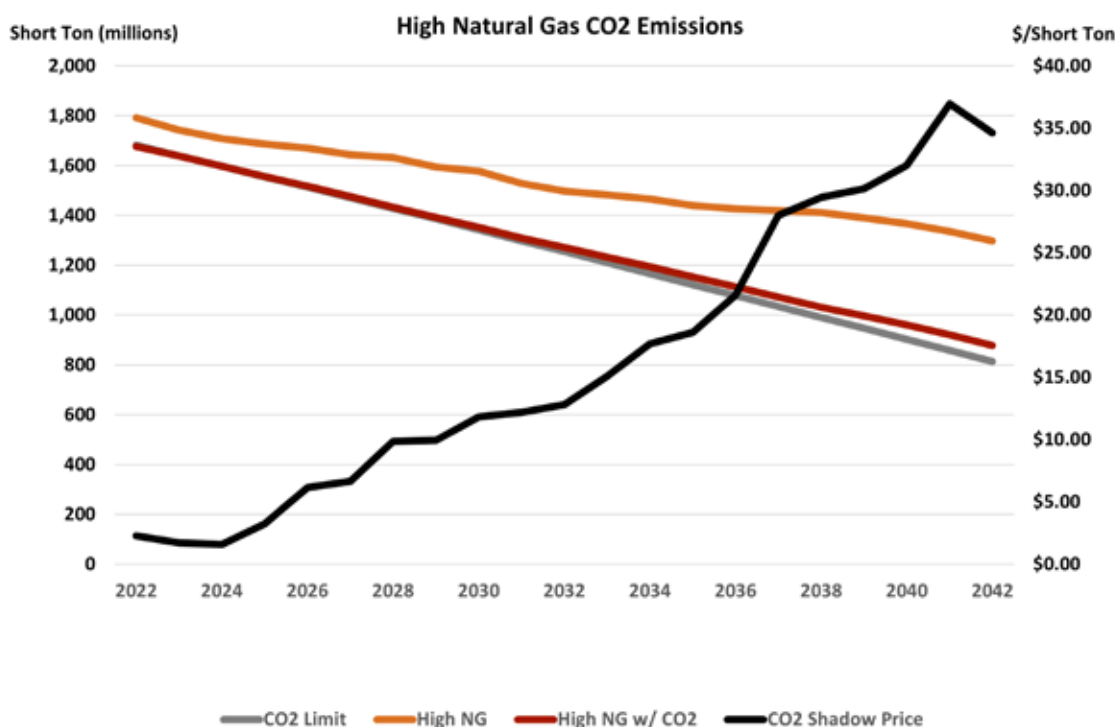


Figure 12.3-5: High Natural Gas with Carbon Limit - CO2 Shadow Price



- **The Low Natural Gas with Carbon Limit** scenario imposes a carbon limit consistent with the Paris Climate Accord. In Figure 12.3-6, the gray line shows the carbon limit, the blue line shows the Low Natural Gas scenario carbon emissions without a limit, and the light orange line shows the carbon emissions with a limit. The 2nd Y-Axis, black line, is the calculated shadow price of achieving the limit. The shadow price is applied as a carbon cost to KYMEA portfolios when analyzing this scenario.

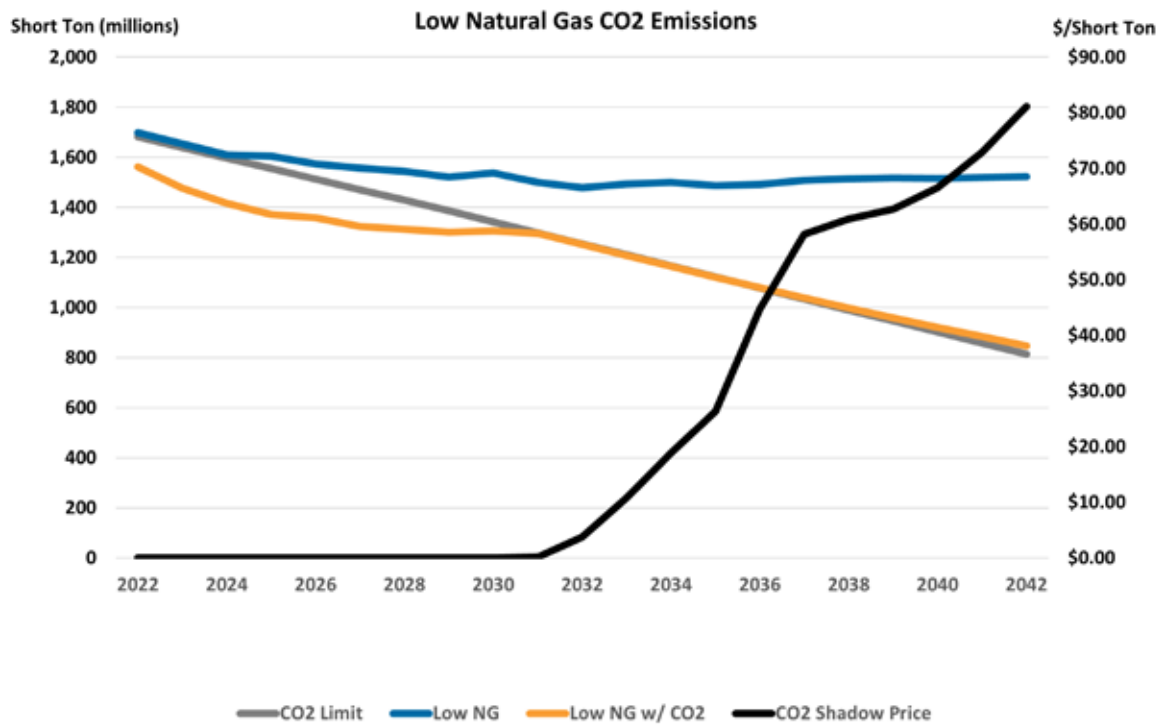


Figure 12.3-6: Low Natural Gas with Carbon Limit - CO2 Shadow Price



- **The Carbon Tax** scenario shown in Figure 12.3-7 applies a tax to fossil fuels based on the amount of carbon dioxide released when the fuel is burned. The primary purpose of a carbon tax is to lower greenhouse-gas emissions by penalizing fossil fuels and encourage the use of non-carbon energy such as nuclear energy and renewables.

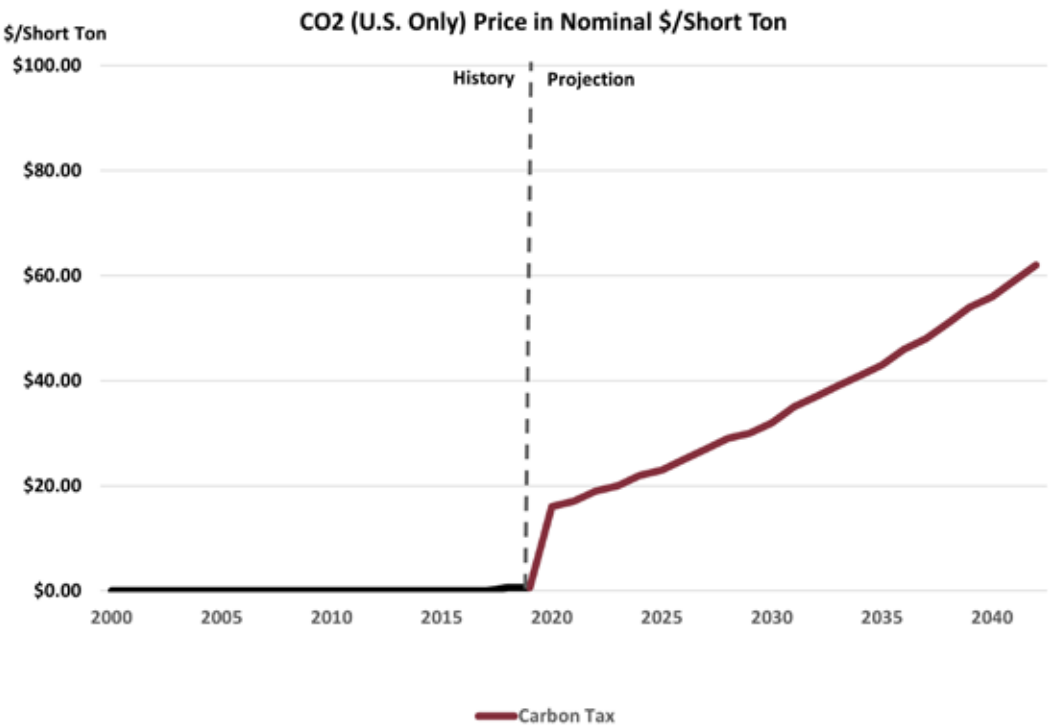


Figure 12.3-7: Carbon Tax (\$/MWh)



Carbon Emission Limit Scenarios

In the four carbon emission limit scenarios (Zero Carbon Additions, High Natural Gas with Carbon Limit, Low Natural Gas with Carbon Limit, and Carbon Tax), shown in Figure 12.3-8, U.S. CO₂ emissions decrease from 68% to 77% below 2005 levels by 2042.

- **Zero Carbon Additions** scenario limits new generation additions to only technologies which do not emit carbon. Overall demand growth is lower due to increased energy efficiency standards and more distributed generation. In this scenario, the U.S. energy mix is 45% wind, solar, and distributed generation. The carbon reduction is 73% under 2005 levels by 2042.
- **High Natural Gas with Carbon Limit** scenario is consistent with the Paris Climate Accord. The limits are achieved through the application of a carbon tax. Environmental policies and regulations on fracking drive natural gas prices higher. In this scenario, the energy mix is 43% wind and solar, and the carbon reduction is 68% under 2005 levels by 2042.
- **Low Natural Gas with Carbon Limit** scenario is consistent with the Paris Climate Accord. The limits are achieved through the application of a carbon tax. In this scenario, fracking is encouraged as low natural gas prices accelerate coal retirements. By 2035, 99% of the coal units have been retired due to economics. In this scenario, the carbon reduction is 70% under 2005 levels by 2042.
- **Carbon Tax** scenario imposes a carbon tax on all CO₂ emissions. In this scenario, existing conventional nuclear power plants extend their licenses to 80 years to provide carbon free generation. The carbon reduction is 78% under 2005 levels by 2042.

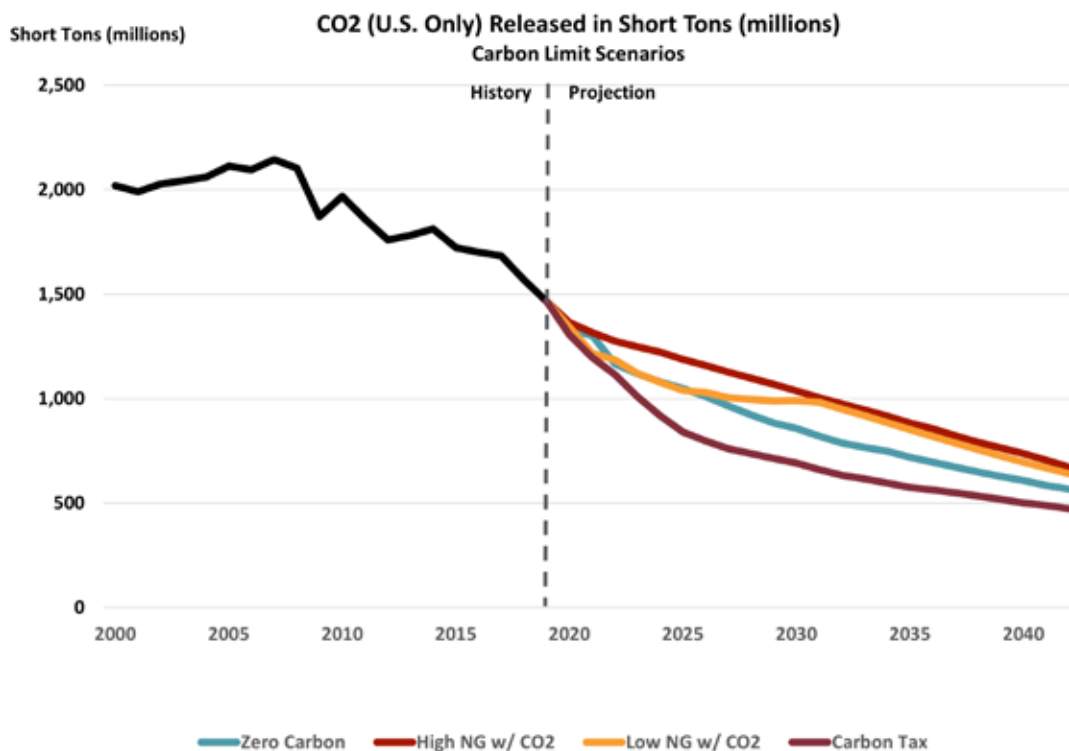


Figure 12.3-8: Carbon Limit - U.S. Power Sector CO₂ Emissions (MM short tons)



The four carbon limit scenarios are successful in pushing the carbon intensity rate below the level of the Status Quo scenario as shown in Figure 12.3-9. A carbon tax produces the lowest carbon intensity rate, while the remaining three carbon limit scenarios produce a similar reduction trajectory, albeit not as rapid as a carbon tax scenario.

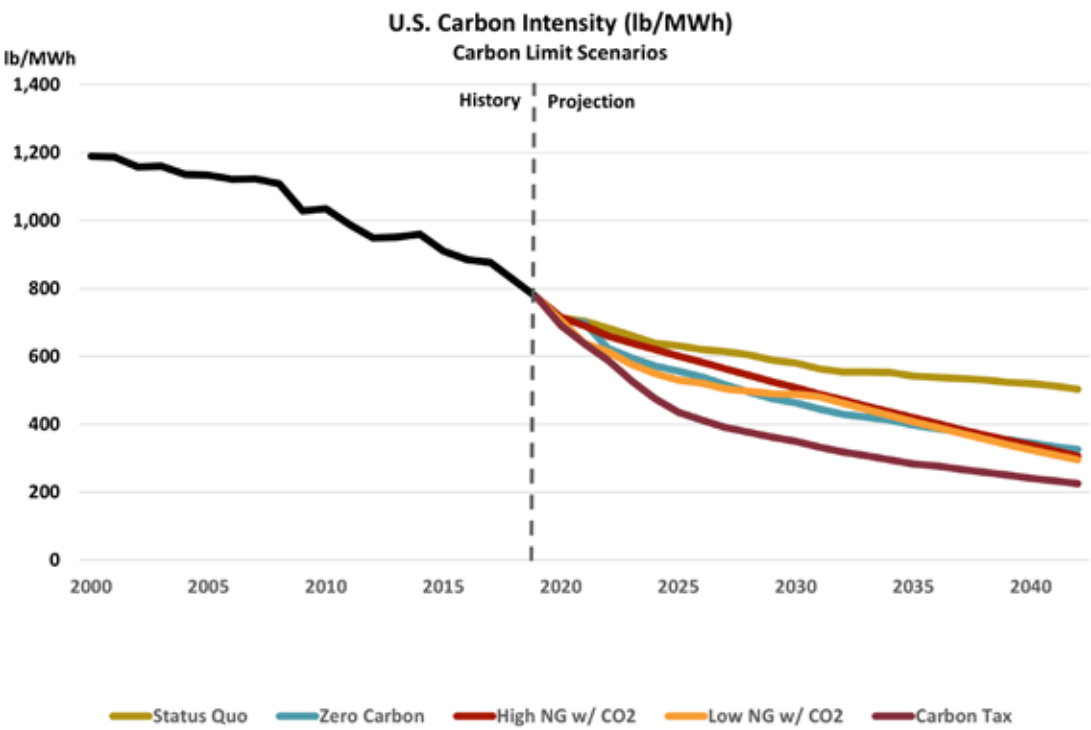


Figure 12.3-9: Carbon Limit - U.S. Power Sector Carbon Intensity (lb/MWh)



12.4 Additions & Retirements

Scenario Capacity Additions

In Figure 12.4-1 and 12.4-2, the Low Natural Gas and High Demand scenarios add the most combined cycle generation while the Zero Carbon Additions and High Natural Gas with Carbon Limits scenarios add the least amount of combined cycle generation. All nine scenarios are bullish on solar generation. The economics of the High Natural Gas scenario add significant solar and wind generation in the absence of any carbon limits. The least amount of wind and solar is added in the Low Natural Gas scenario.

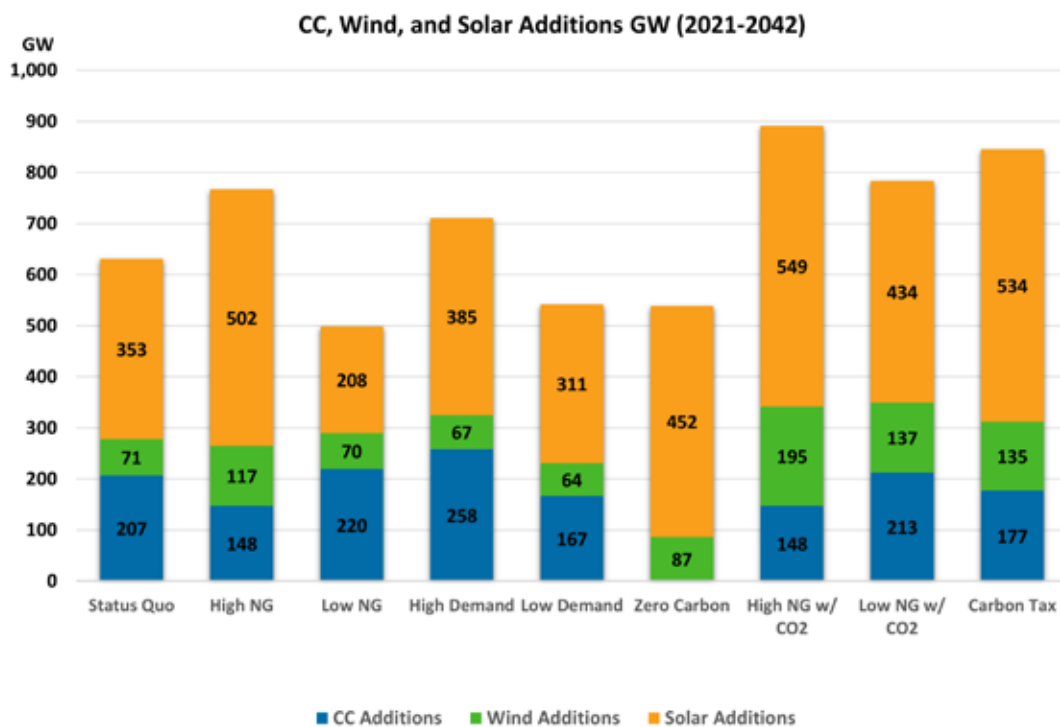


Figure 12.4-1: CC, Wind, and Solar Capacity Additions (GW)

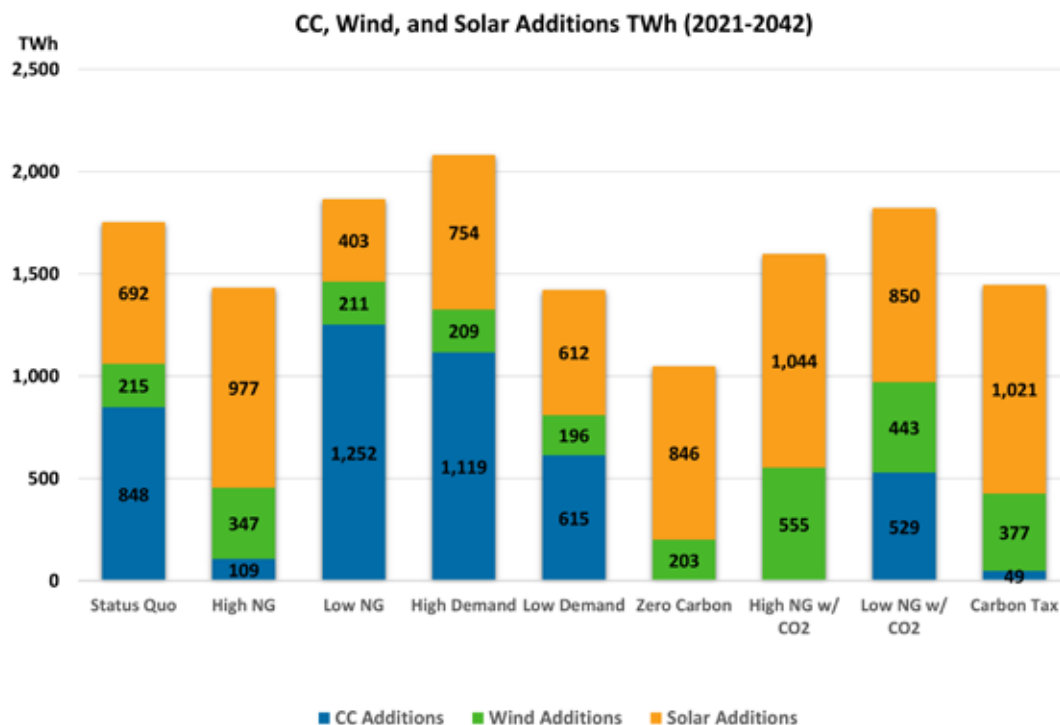


Figure 12.4-2: CC, Wind, and Solar Energy Additions (TWh)

Given the vast amount of wind added in all nine scenarios, anywhere from a 70 to 195 GW increase from 2020 to 2042, a great deal of transmission infrastructure will need to be added, where the wind (blue bubbles) will be transmitted to load centers (red bubbles), as illustrated by Figure 12.4-3.

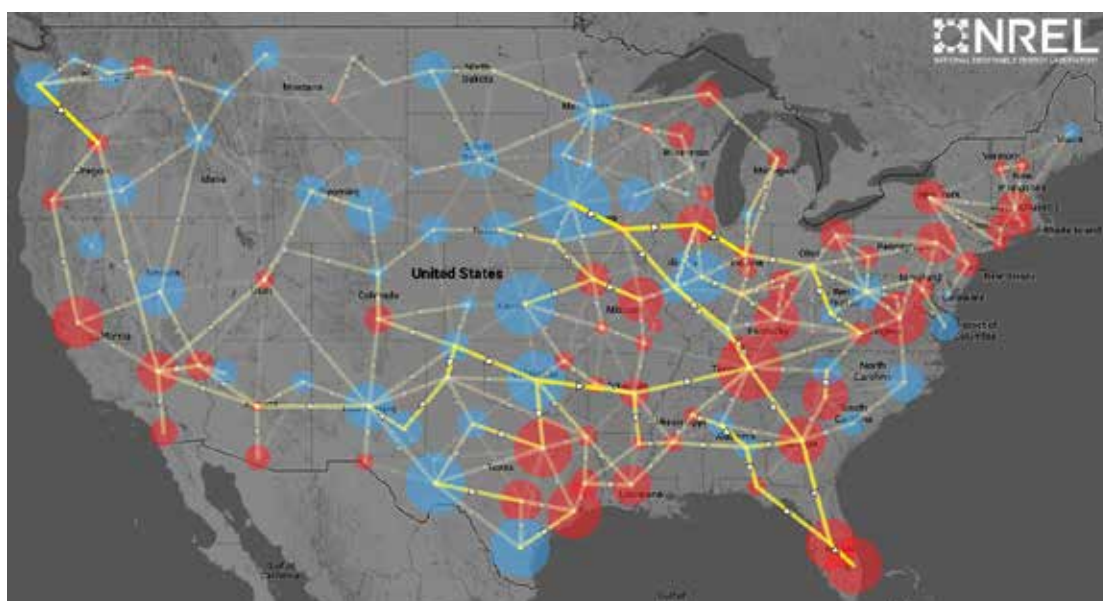


Figure 12.4-3: Wind and Transmission Map¹¹³



MISO Wind and Transmission Additions

The wind additions in MISO are of interest to KYMEA. It is expected that additional wind generation will put downward pressure on MISO market prices, upward pressure on ancillary services, and upward pressure on transmission rates. In 2020, the MISO wind generation is 24 GW.

Figure 12.4-4 illustrates that the most wind added in MISO occurs in the High Natural Gas with CO₂ Limit scenario. The placement of the wind additions in MISO are likely to be in the Dakotas, Minnesota, Iowa, and Illinois, where the wind speed is greatest.

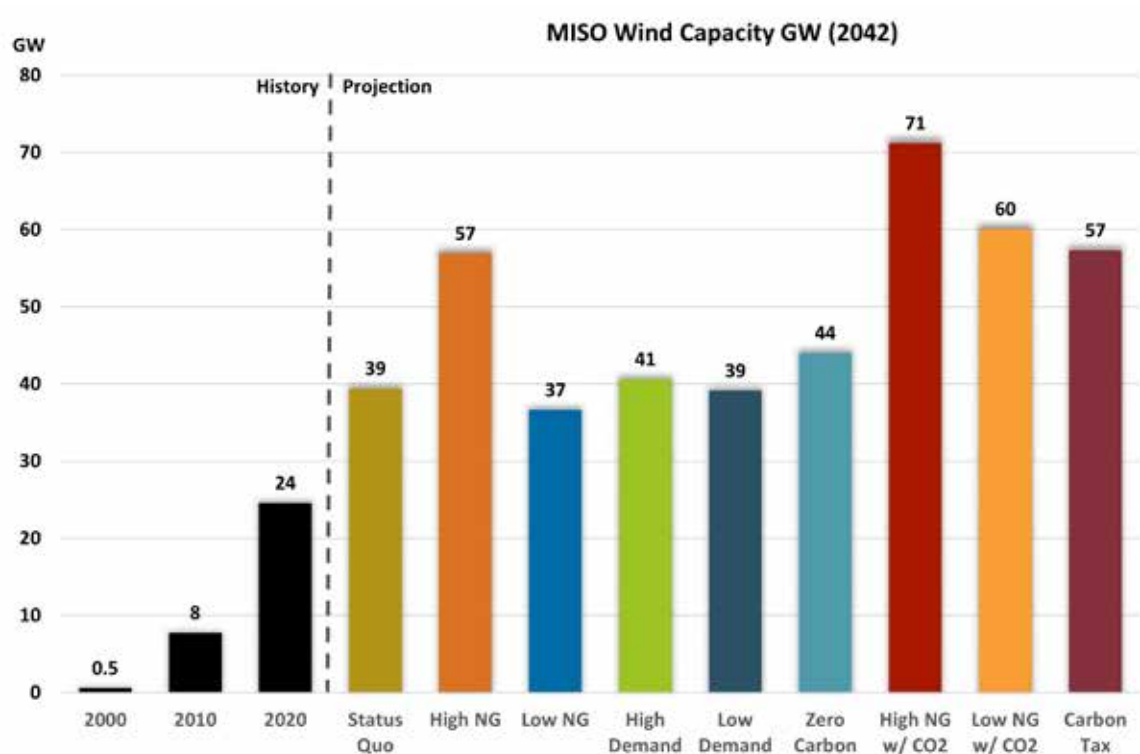


Figure 12.4-4: 2042 MISO Wind Capacity (GW)



Moving the wind energy to the load centers requires significant transmission investment. Figure 12.4-5 from the Eastern Interconnection Planning Collaborative (EIPC) illustrates a proposed plan of high voltage AC and DC transmission paths to deliver the wind energy. The 2013 EIPC study is a future scenario of a nationally implemented federal carbon policy. In 2010 dollars, EIPC Scenario 1 was estimated to cost about \$978B.

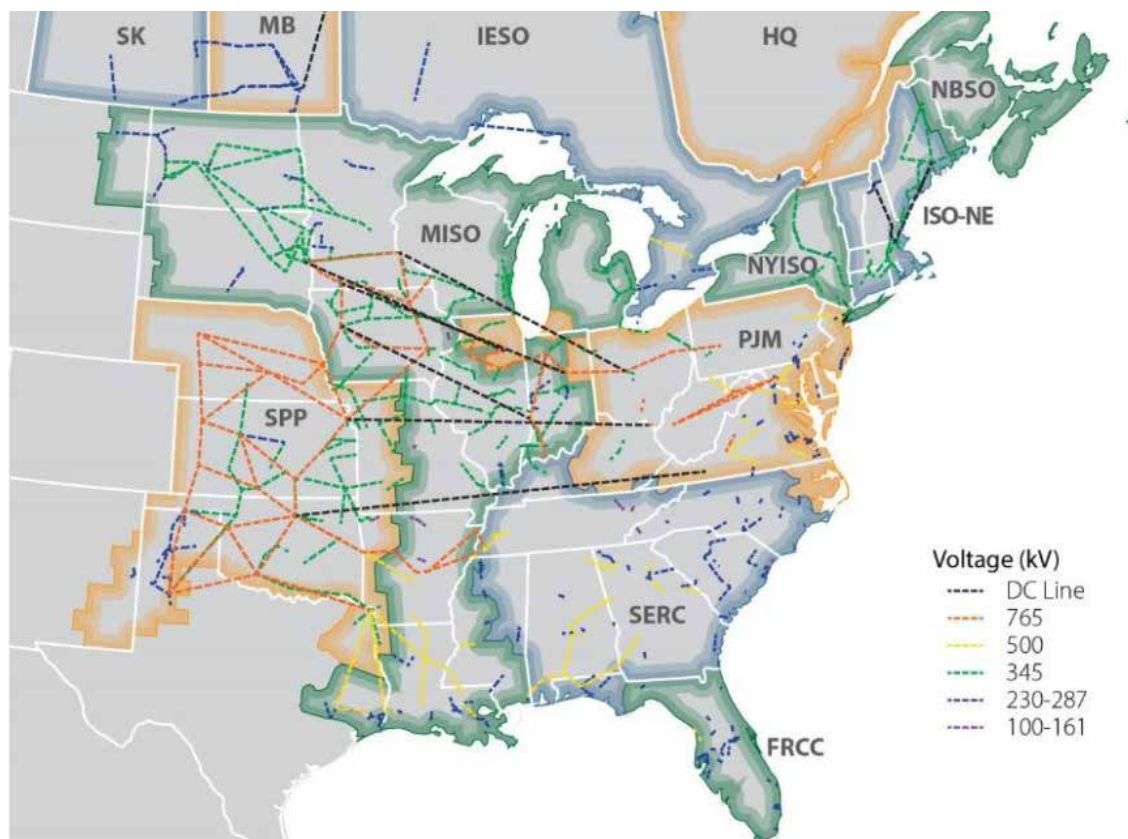


Figure 12.4-5: 2013 EIPC Scenario 1 Transmission Expansion¹¹⁴

MISO creates Multi-Value Projects to recover the cost of the wind-related transmission investment. Each Multi-Value Project undergoes a benefit-cost analysis to ensure that the transmission cost is outweighed by the benefits, including interconnection-wide reliability. The cost is recovered by a regional tariff applied to those benefiting from the project. As a buyer of MISO energy, KYMEA is charged the tariff rate for each MWh that is purchased from MISO. Currently, the tariff (26a) rate from the 2011 Multi-Value Projects is around \$1.63 per MWh. It is expected the next round of Multi-Value Projects will be significantly higher as the amount of wind being moved and the transmission required will be far greater.

114 Eastern Renewable Generation Integration Study (Rep. No. NREL/TP-6A20-64472). (2016, August). Retrieved April 27, 2021, from NREL, 2 RePPAE LLC, GE website: <https://www.nrel.gov/docs/fy16osti/64472.pdf>



To account for varying amounts of wind generation and required transmission investment, each of the nine scenarios has a unique MISO firm transmission cost trajectory expressed in \$/kW-MO. On average, the CAGR is expected to be 5%. Figure 12.4-6 illustrates that the highest CAGR occurs in the High Natural Gas with CO₂ Limit scenario which has the most wind.

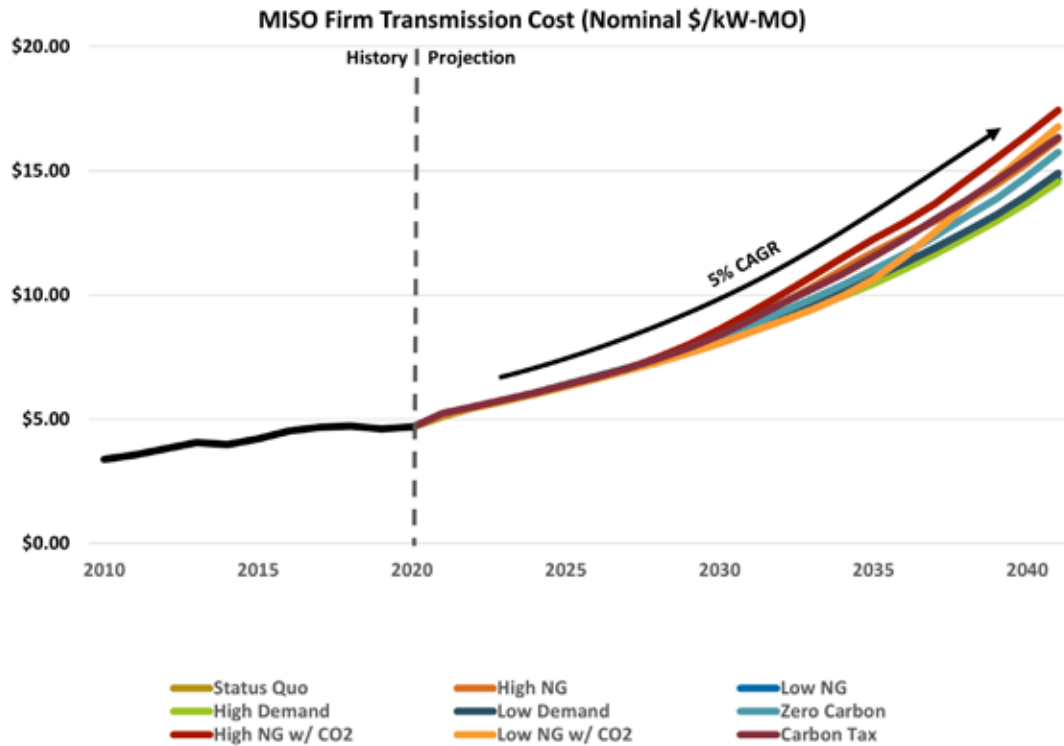


Figure 12.4-6: MISO Firm Transmission Costs (\$/kW-MO)



Scenario Capacity Retirements

Due to age and economics, all nine scenarios experience a significant number of coal and nuclear retirements. The four carbon limit scenarios include nuclear license extensions. The Carbon Tax scenario extends licenses to 80 years. Figure 12.4-7 illustrates that the High Natural Gas scenario produces the lowest amount of coal retirements.

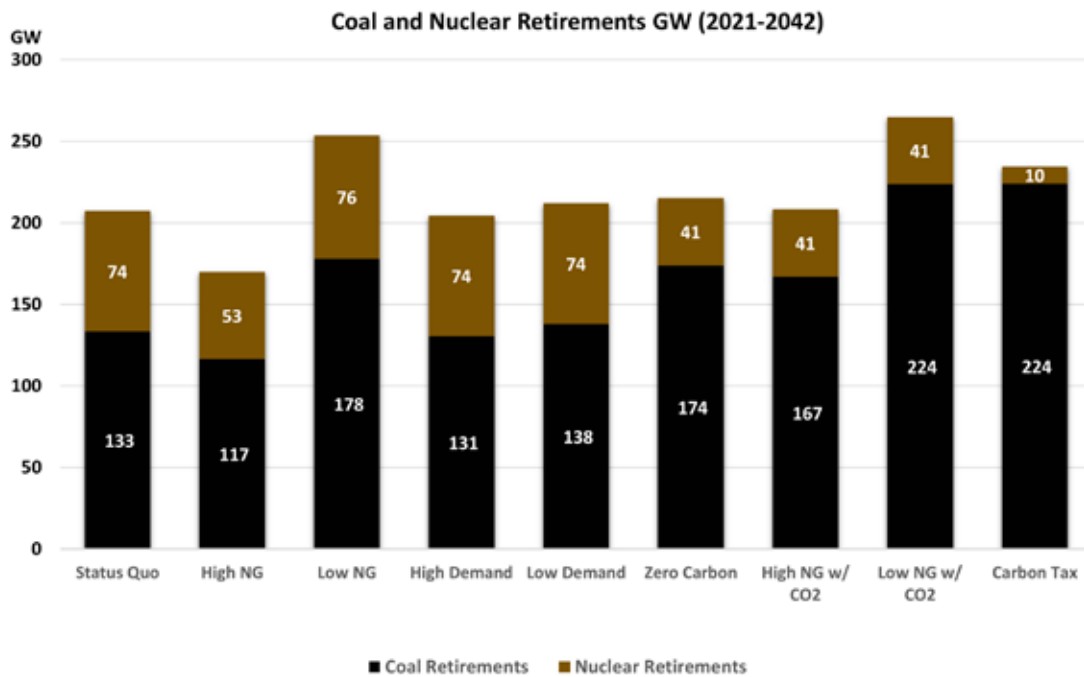


Figure 12.4-7: Coal and Nuclear Retirements (GW)



12.5 Energy, Capacity, & Ancillary Service Prices

Scenario Wholesale Energy Prices

The four carbon limit scenarios produce the highest market prices as either a carbon shadow price or carbon tax drives wholesale energy prices higher. The Low Natural Gas scenario prices are 45% below Status Quo scenario by 2042. The long-term energy price growth rate of the Status Quo scenario is 2.5%.

Figure 12.5-1 illustrates the projected around-the-clock (ATC) energy prices. The High Natural Gas with CO₂ Limit scenario has the highest price trajectory, while the Low Natural Gas scenario has the lowest trajectory.

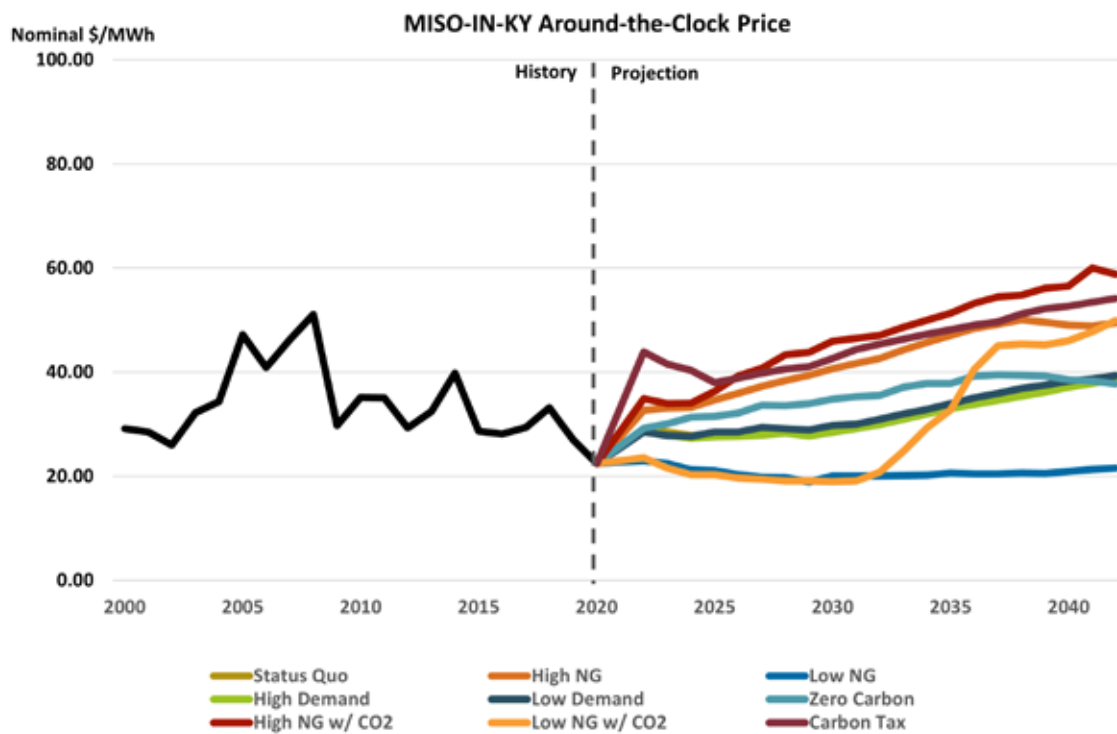


Figure 12.5-1: MISO-IN-KY Annual ATC Energy Prices (nominal \$/MWh)



Scenario Capacity Prices

MISO holds a voluntary annual capacity auction called a PRA. The PRA provides a way for MISO Market Participants to meet resource adequacy requirements. The PRA's location-specific approach encourages resources to participate in the zones where they provide the most benefit. The left-hand side of Figure 12.5-2 illustrates the MISO Zone 6 PRA auction results. As discussed in Section 11, the PRA has historically cleared at a meager price as the voluntary capacity market construct and corresponding resource offer curve results in over 96% of the offers at a penny or less per MW-Day. As stated by the MISO market monitor, "The PRA Auction is a poor reflection of the true reliability value of capacity."

Conversely, the right-hand side of Figure 12.5-2 illustrates the projected investment value of capacity, which includes a regulated return on investment. The EnCompass calculated capacity value is a far better indicator of the bilateral capacity market from which KYMEA can purchase capacity.

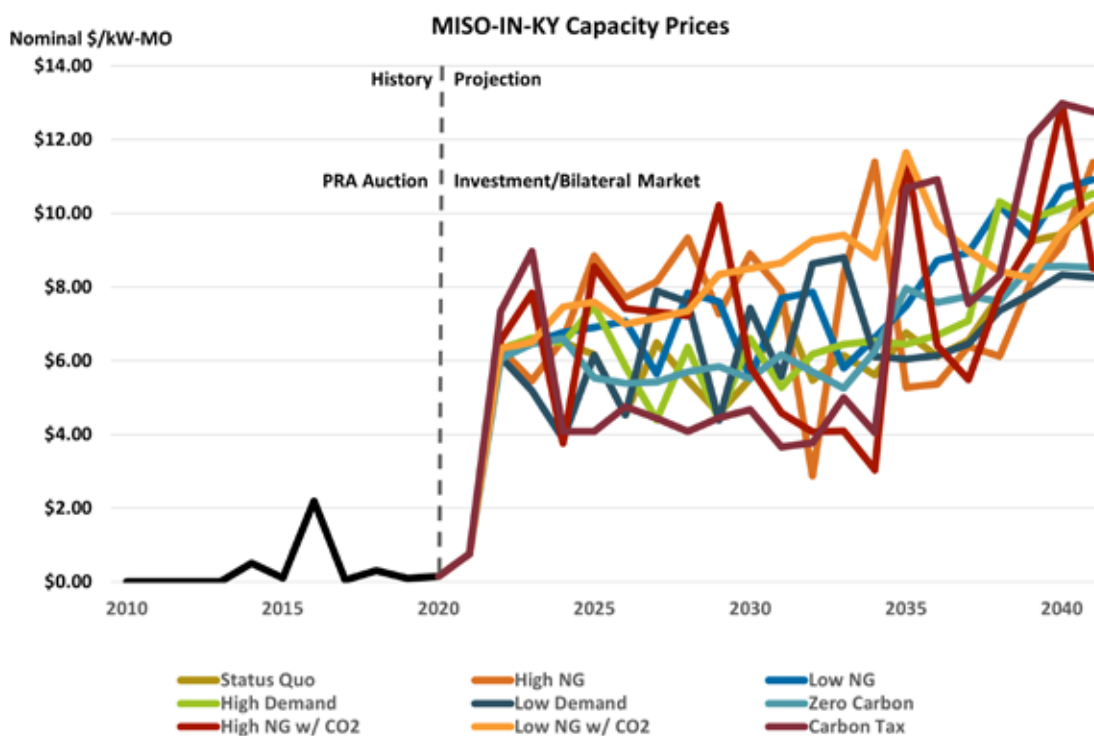


Figure 12.5-2: MISO-IN-KY Capacity Prices (nominal \$/kW-MO)



Scenario Ancillary Service Prices

EnCompass calculates the marginal cost (shadow price) of meeting energy and ancillary service requirements. The wholesale energy price results were illustrated earlier in this report. The ancillary service prices, as calculated from the co-optimization simulation for spinning reserve, supplemental reserve, and regulation (up and down), are shown in Figure 12.5-3 through Figure 12.5-6.

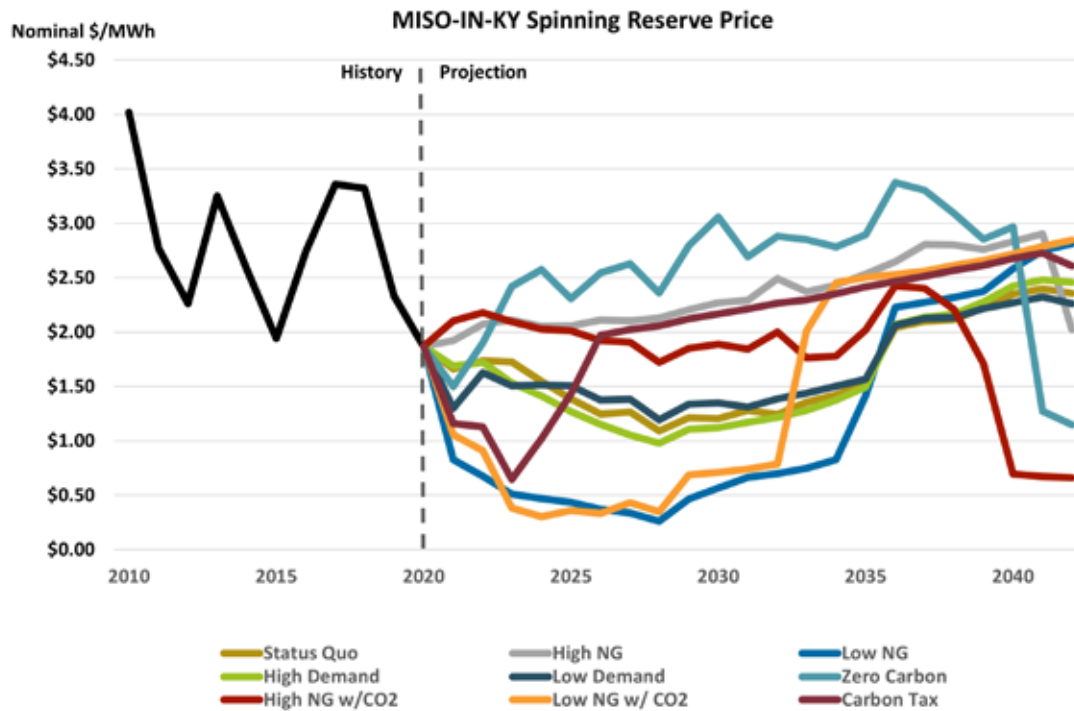


Figure 12.5-3: MISO-IN-KY Spinning Reserve Prices (nominal \$/MWh)

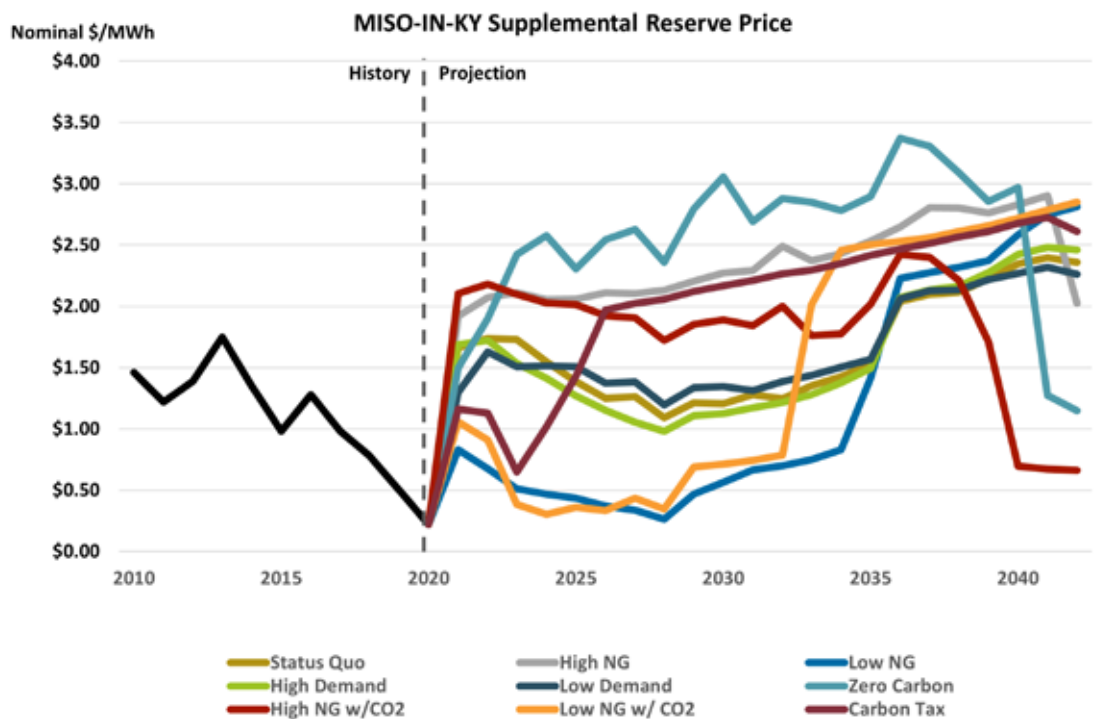


Figure 12.5-4: MISO-IN-KY Supplemental Reserve Prices (nominal \$/MWh)

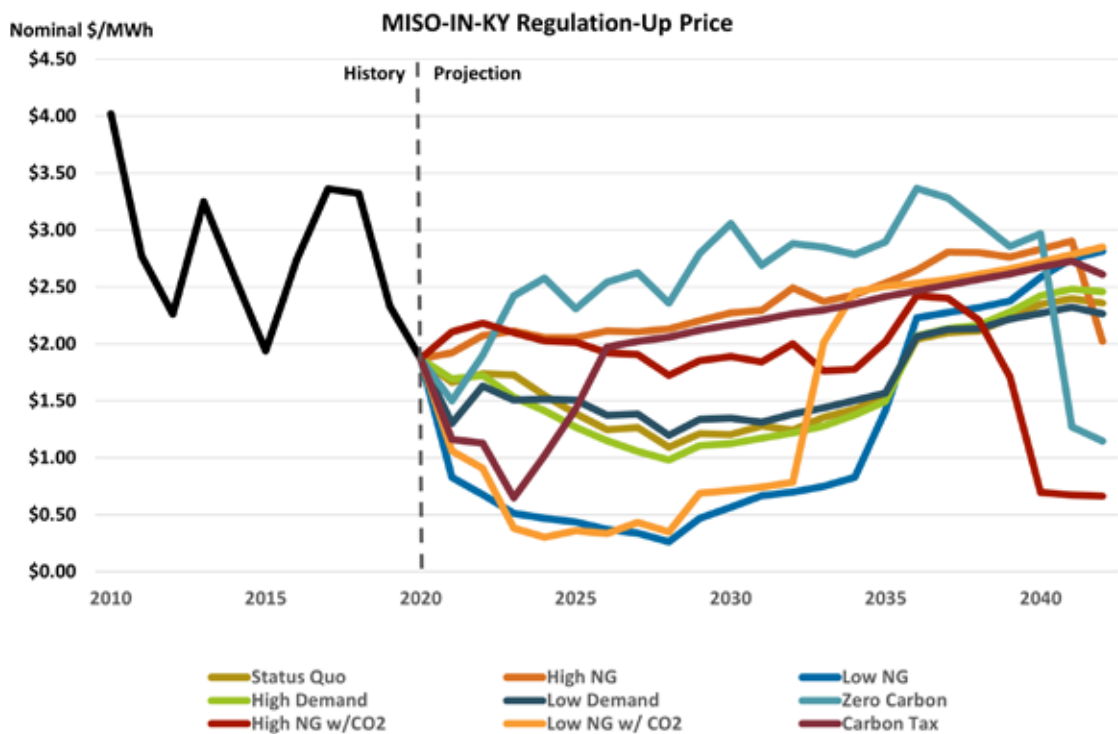


Figure 12.5-5: MISO-IN-KY Regulation-Up Prices (nominal \$/MWh)

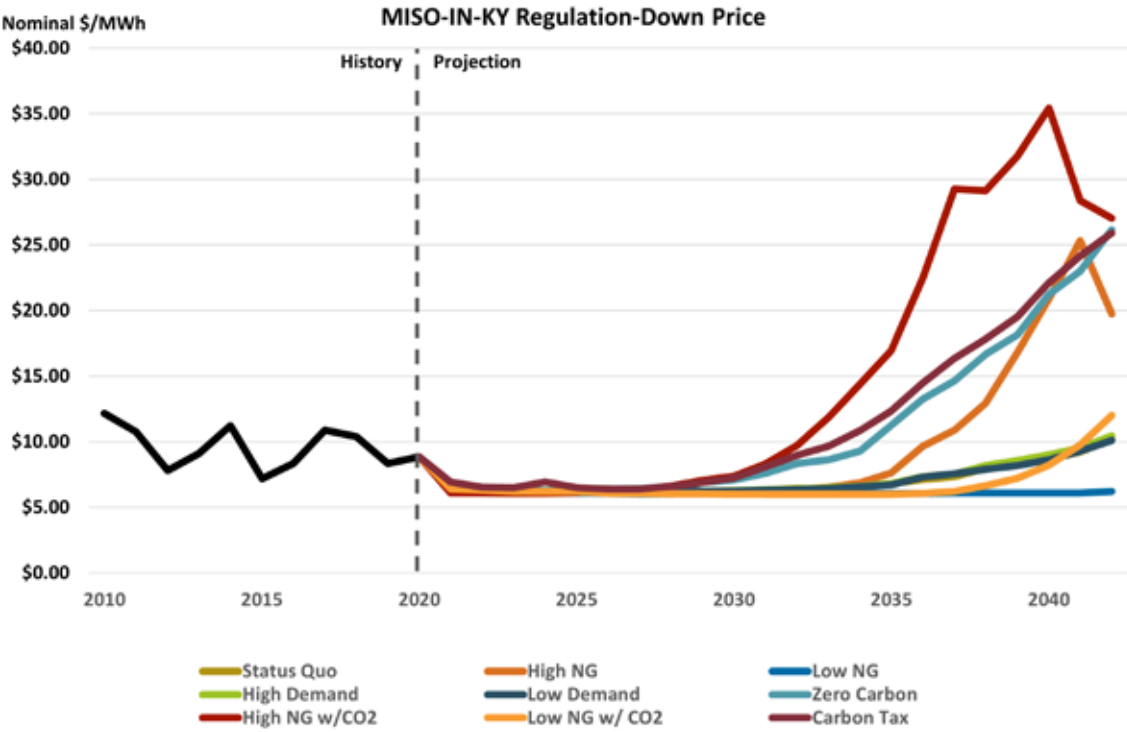
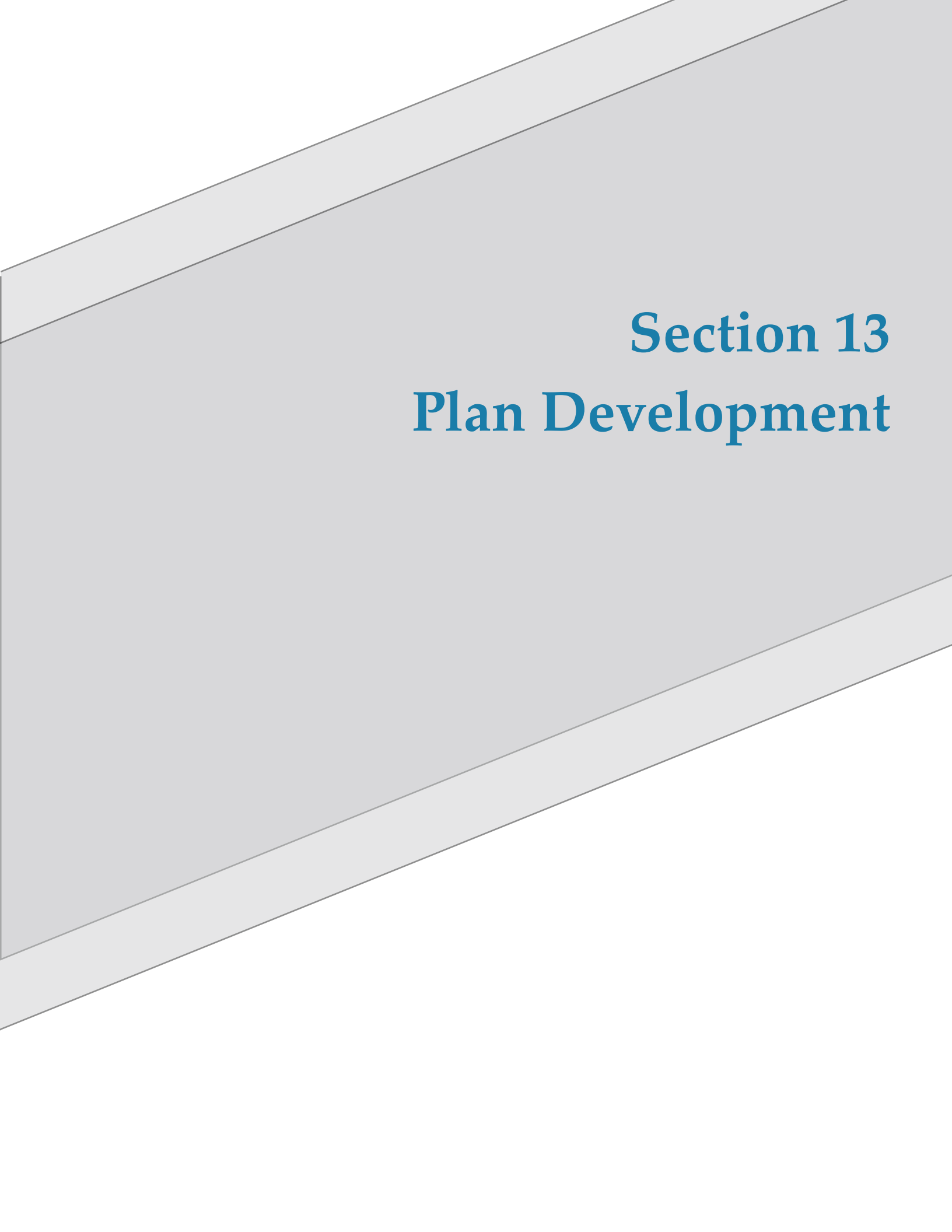


Figure 12.5-6: MISO-IN-KY Regulation-Down Prices (nominal \$/MWh)



Section 13

Plan Development

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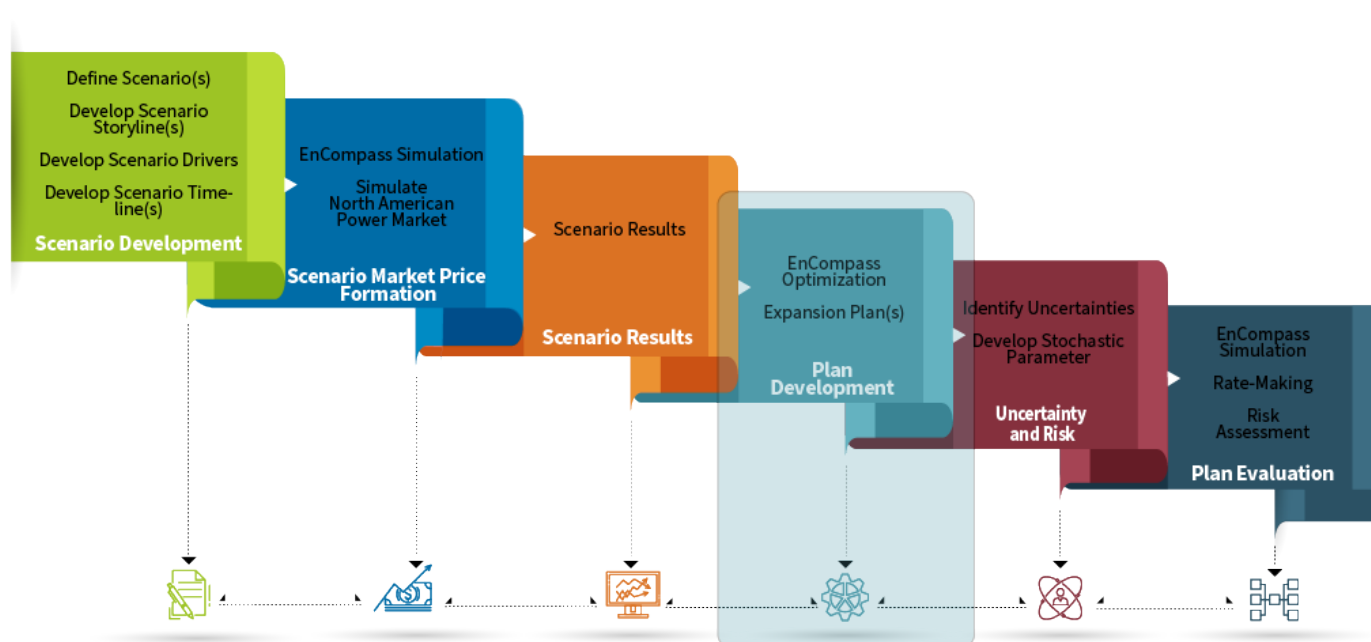
13. PLAN DEVELOPMENT

13.1 Modeling Approach

The previous three sections of this report describe the development, modeling, and results of nine plausible scenarios for the North American power market.

The next step in the IRP Flowchart is the KYMEA Plan Development. Whereas, Scenario Development, Market Price Formation, and Results seek to understand how market drivers, energy/environmental policies, customer preferences, and regulatory/market rules guide the landscape of the North American power markets; Plan Development focuses on KYMEA specific plans and how those plans perform under the nine plausible scenarios.

IRP FLOWCHART



Planning Horizon and Decision Periods

The planning horizon for the integrated resource planning study is 22 years (May 1, 2019, through May 31, 2042). IRP2020 coincides with the start of KYMEA operations on May 1, 2019. For the development of KYMEA's plans, there are three distinct planning periods.

1. **Existing-Term:** May 1, 2019 – May 31, 2022 (3 Years)
2. **Near-Term:** June 1, 2022 – May 31, 2027 (5 Years)
3. **Long-Term:** June 1, 2027 – May 31, 2042 (14 Years)



13.2 Capacity Supply/Demand Balance

The Capacity Supply/Demand Balance Figure 13.2-1 illustrates the projected capacity and reserve balance with KYMEA's existing resources and projected demand. Note that planning years 2020 and 2021 include the impact of the COVID-19 pandemic on peak demand. Peak demand is assumed to recover by April 2022. KYMEA members Benham and Berea, who are currently transmission-only members, participated in the IRP and are included in the figure as a second demand line, as illustrated by the shaded gray area.

1. **Existing-Term:** KYMEA's existing portfolio consists of the following five resources.
 - **IPMC-Joppa:** 100 MW (6/1/2019 – 5/31/2022)
 - **BREC-Wilson:** 100 MW (5/1/2019 – 5/31/2029)
 - **PPS-Peakers:** 90 MW (5/1/2019 – 5/31/2023)
 - Option Period: 30 to 90 MW (6/1/2023 – 5/31/2029)
 - **SEPA-Hydro:** 32 MW (5/1/2019 – end of hydro life)
 - **Paris-Diesels:** 11 MW (5/1/2019 – 5/31/2029)
2. **Near-Term:** In 2022, KYMEA has a need for additional capacity to replace the expiring IPMC-Joppa 100 MW PPA. The overall need is 100 MW for the AR Group and 128 MW when including Berea and Benham.
 - **December 2022:** Ashwood (54 MW) comes online.
 - **June 2023:** KYMEA has a one-time option to adjust the PPS-Peakers from 90 MW to as low as 30 MW.
 - **May/June 2024:** Berea and Benham, respectively, can join the AR Group as their existing PPAs expire.
3. **Long-Term:** From 2029-2042, the overall need is 252 MW for the AR Group and 280 MW when including Berea and Benham.
 - **TSR1:** 100 MW MISO point-to-point transmission reservation expires 4/30/2027.
 - **TSR2:** 100 MW MISO point-to-point transmission reservation expires 5/31/2029.
 - **June 2029:** KYMEA has only Ashwood Solar and SEPA Hydro as commitments.

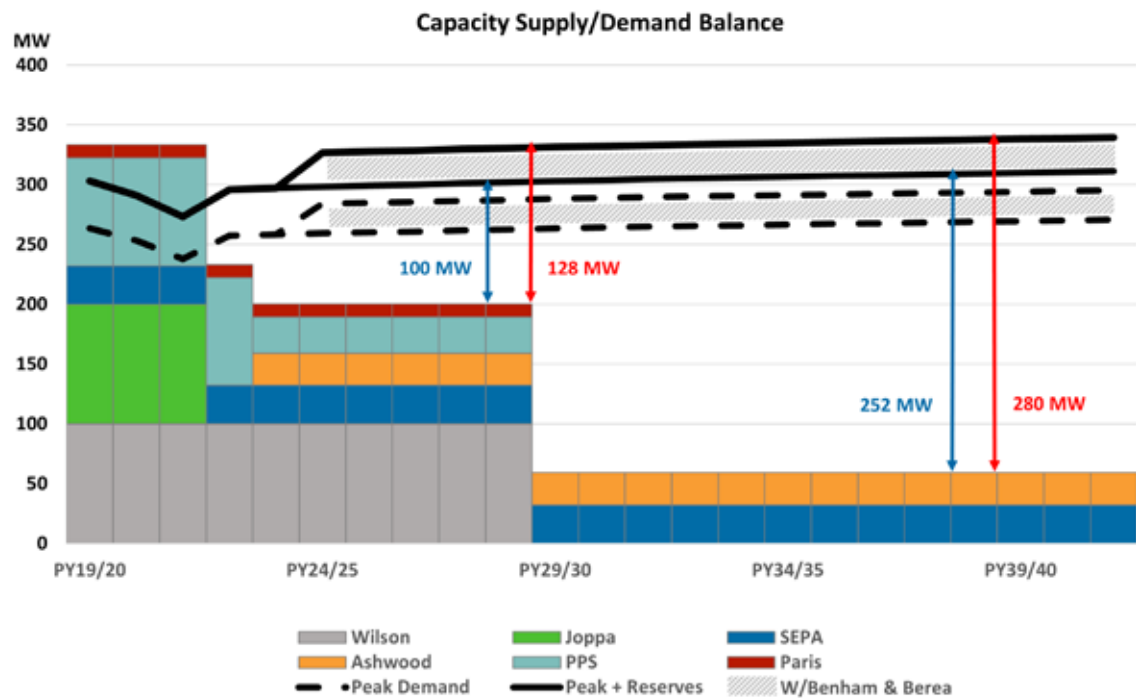


Figure 13.2-1: Capacity Supply/Demand Balance



13.3 Near-Term Resource Plan

The initial step in the near-term resource needs analysis is to broadly identify KYMEA's need for capacity and energy using a load duration curve.

Identify Near-Term Capacity and Energy Needs with Load Duration Curve

As evidenced by the Capacity Supply/Demand Balance in Section 13.2, the overall AR Project capacity need, including reserves, is 100 MW.

The Load Duration Curve analysis shown in Figure 13.3-1 illustrates that of the 100 MW capacity need, 30 to 60 MW of intermediate capacity with energy fills the void highlighted by the gray area. The intermediate block satisfies nearly 25% of the KYMEA's energy needs. It is expected the intermediate product would dispatch at a 30% to 50% capacity factor depending upon the terms and dispatch price.

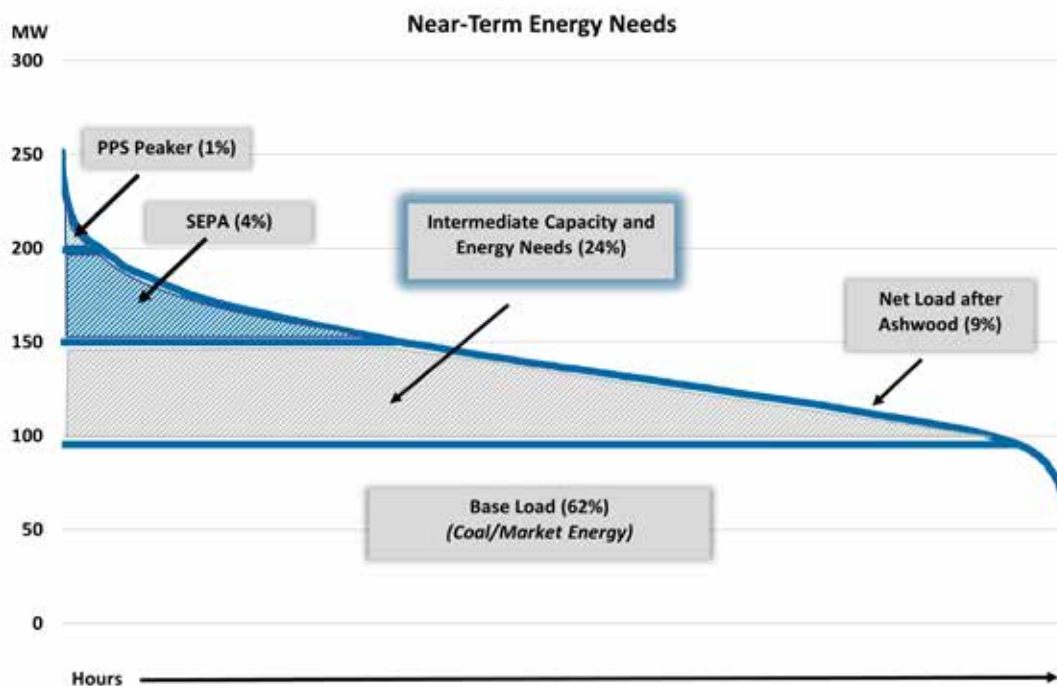


Figure 13.3-1: Near-Term Energy Needs



Indicative RFP2020

KYMEA issued an Indicative RFP in August 2020. The purpose of the Indicative RFP2020 was to gauge the market opportunities and options for KYMEA's next power supply tranche to fit the intermediate need identified by the load duration curve analysis. Below is a synopsis of the RFP issued.

RFP2020 Synopsis

The Kentucky Municipal Energy Agency (KYMEA) seeks written proposals from qualified suppliers of electric intermediate capacity and energy resources. KYMEA intends to purchase power from one or more suppliers commencing on June 1, 2022 for terms of 3 to 20 years.

Resources should: (i) be deliverable on a firm, non-interruptible basis to the LGE/KU transmission system, (ii) be delivered to KYMEA on a first call basis and not be committed for sale to third parties, and (iii) qualify for designation as network resources under the LGE/KU Open Access Transmission Tariff ("OATT") to serve the loads of KYMEA's Member municipal electric systems.

Proposers may propose a specific amount of capacity or indicate that the amount of capacity to be purchased would be within a range from 30 MW to 60 MW, with the specific amount to be determined during negotiation of the power purchase agreement. The expected capacity factor is between 30% and 50%.

Proposers are required to submit by email their questions pertaining to this RFP no later than 2 pm EDT on August 12, 2020, and their proposals no later than 2 pm EDT on August 19, 2020, and meet other requirements specified in this RFP.



RFP2020 Responses

The RFP produced 32 proposals from 11 respondents. The proposals included ownership and PPA options for the specified capacity and energy product. Also included were solar and battery storage proposals. In Figure 13.3-2, the RFP responses were organized as either a Capacity/Energy proposal or a Solar/Storage proposal.

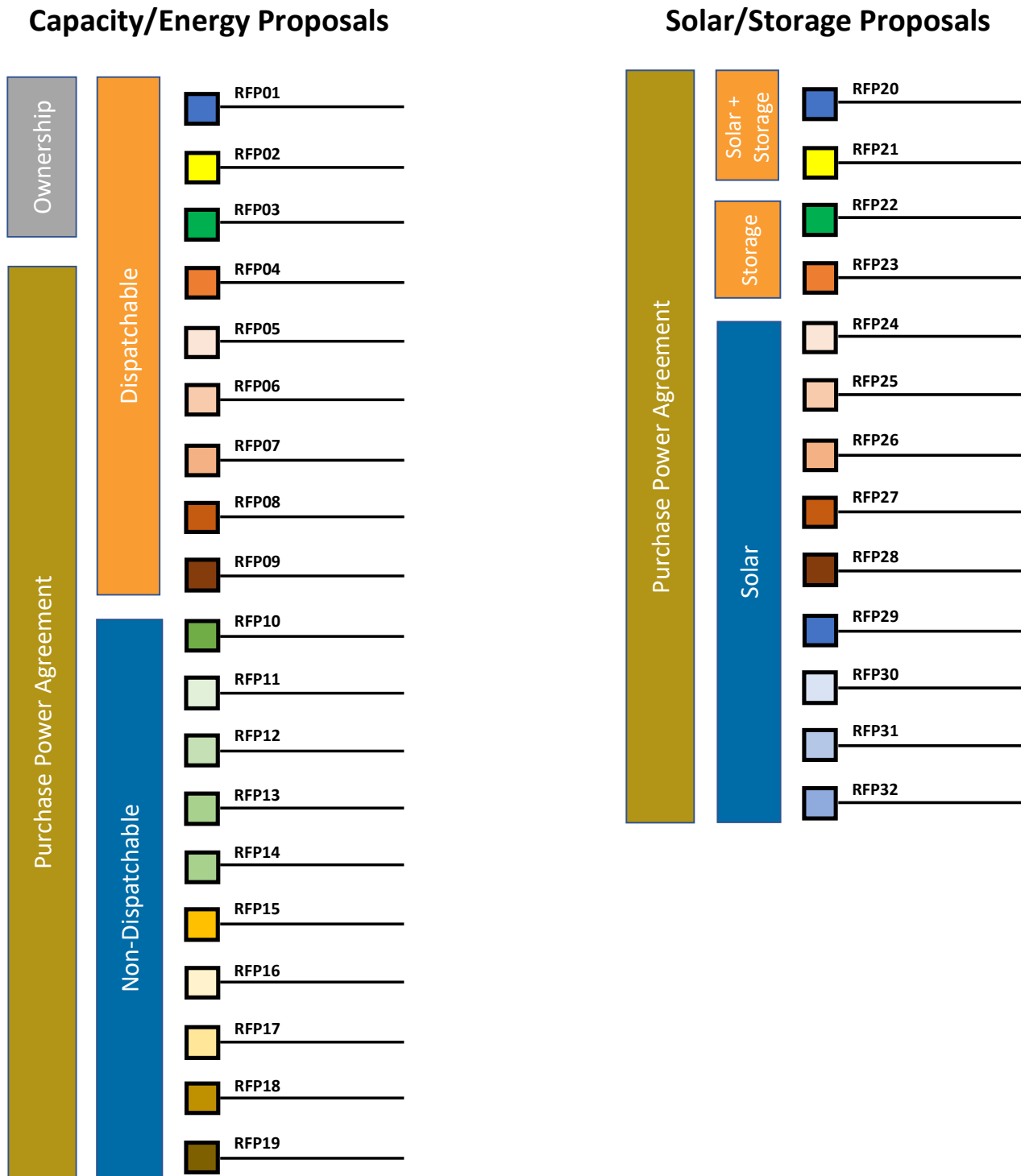


Figure 13.3-2: RFP2020 Response Tree



RFP2020 Response Summary

KYMEA is unable to publicly share the specific RFP responses due to non-disclosure agreements (NDA). The responses can be categorized as:

- Reciprocating Internal Combustion Engines (RICE)
- Aeroderivative Gas Turbine
- System Dispatchable Capacity/Energy
- 7x24 Fixed Price Capacity/Energy
- 5x16 Fixed Price Capacity/Energy
- 7x24 Indexed Price Capacity/Energy
- 5x16 Indexed Price Capacity/Energy
- Solar
- Solar + Storage
- Storage Only



Solar Saturation

The majority of KYMEA's load resides inside the LKE transmission system. LG&E/KU operates as a wholesale cost-based monopoly as it does not participate in a competitive marketplace (RTO). As such, KYMEA must be cautious as not to oversize its solar generation as KYMEA has limited ability to sell excess solar energy out of the LKE system without a firm transmission path. KYMEA could purchase hourly non-firm transmission; however, non-firm transmission is subject to availability. Hourly solar generation greater than KYMEA's load is met with stiff imbalance penalties and a requirement to mitigate the imbalance activity within 90 minutes after notification from the BA.

As shown in Figure 13.3-3, the worst case (lowest possible load day) when solar generation outpaces KYMEA's load occurs in the springtime in the months of March and April during the weekend. In the absence of battery storage, the maximum solar size is limited to 105 MW.

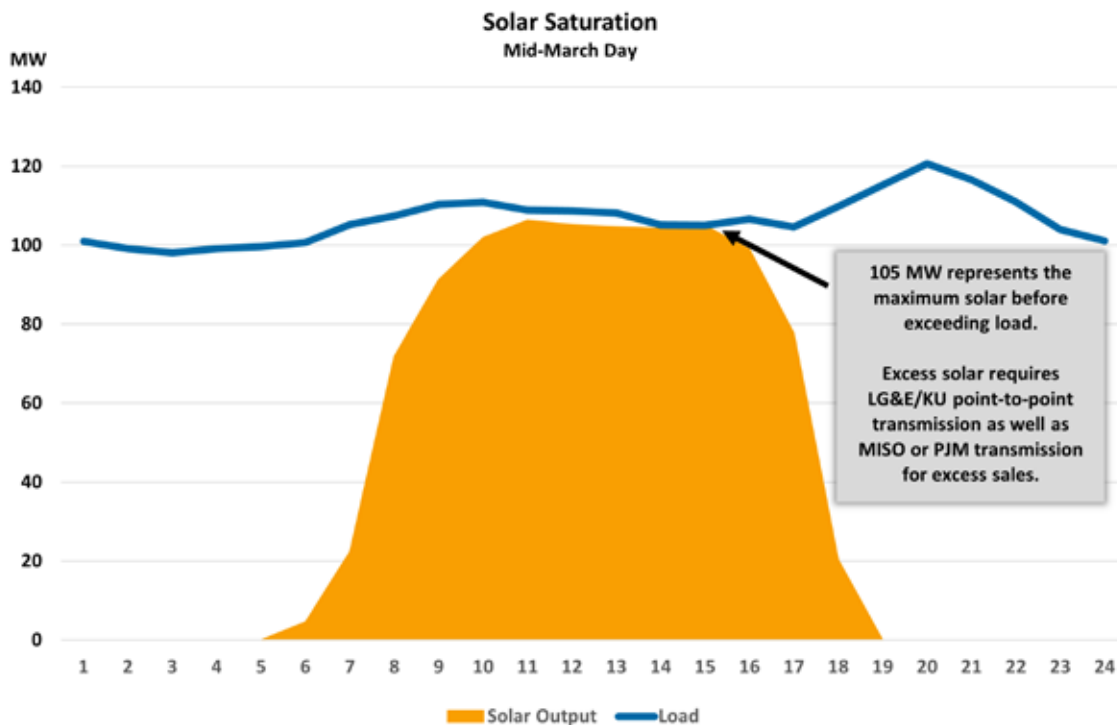


Figure 13.3-3: Solar Saturation Graph



Near-Term Decisions

The responses to RFP2020 provided KYMEA with near-term options to consider for the Agency's capacity and energy needs. In addition to selecting one or more suppliers from the RFP, KYMEA also had several other decisions to make before the end of 2020 or shortly thereafter. Immediate decisions before KYMEA were:

- RFP Capacity/Energy Proposals:** Staff to evaluate and rank the RFP options and provide the results for the Board's consideration by December 31, 2020.
- MISO Point-to-Point Transmission/LKE NITS:** Staff to recommend for the Board's consideration the appropriate size and term of a MISO (Source) point-to-point firm transmission path to the LKE (Sink) and LKE NITS to ensure power delivery and operating reserves to satisfy a 1-in-10 peak demand forecast. The need for the additional MISO PTP and LKE NITS is dependent upon the RFP selection (Item 1) and if the selection was in MISO or in LKE transmission area.
- Paducah Power System (PPS) Peaking Capacity:** By December 31, 2020, KYMEA may exercise a one-time election to decrease the PPS Peaking Capacity from 90 MW to no less than 30 MW. The election, if exercised, commences on June 1, 2023.
- Ashwood Solar I Project:** Ashwood was designed as an 86 MW solar plant of which KYMEA would take 53.75 MW (62.5%), and Owensboro Municipal Utility (OMU) would take 32.25 MW (37.5%). On January 20, 2021, the solar developer, RWE, notified KYMEA that OMU opted to not take their portion. The notification gives KYMEA the right of first refusal (RoFR) to the 32.25 MW.

RFP2020 Capacity and Energy Analysis Decision Tree

The 19 capacity and energy responses were reduced to eight proposals. Proposals that were similar but inferior to a better proposal with similar attributes were not simulated with EnCompass in the interest of reducing the viable options to a manageable size of eight proposals. As illustrated by Figure 13.3-4, KYMEA considered 144 combinations ($8 \times 3 \times 3 \times 2 = 144$) to determine which RFP proposal provided the best fit to meet KYMEA's near-term resource needs.

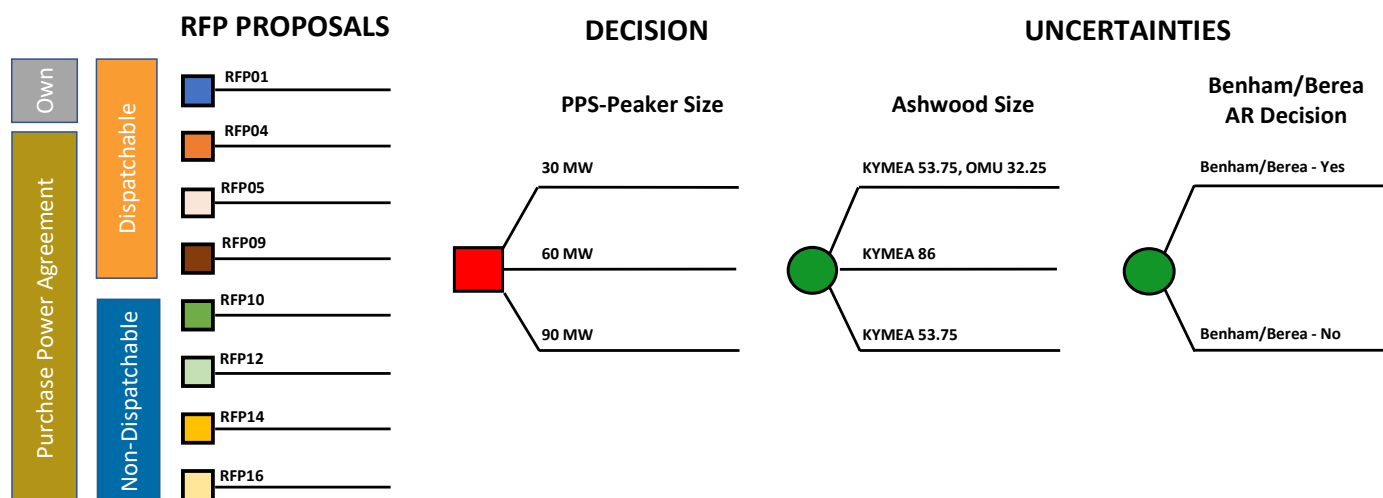


Figure 13.3-4: RFP2020 Decision and Uncertainty Tree



RFP2020 Solar/Storage Proposals

The 13 solar/storage responses were compared against the right of first refusal (RoFR) for the 32.25 MW of Ashwood. Since the Ashwood RoFR was the least-cost choice, no further analysis of the 13 RFP responses was performed. The storage options were eliminated as a viable replacement for the PPS Peakers due to the storage hours (2-4 hours) and cycling limitations of the lithium-ion batteries.

RFP2020 Proposal Selected

From the analysis of the EnCompass production cost simulations, market risk assessment, counterparty risk assessment, term length, additional capacity potential, and energy scheduling flexibility, the Duke Energy-Indiana (DEI) capacity and energy proposal (RFP05) was selected as the preferred option for further analysis.

Five (5) Near-Term Decision Elements

With the inclusion of the DEI proposal, there were five (5) near-term decision elements before the KYMEA Board of Directors, which needed to be made by the end of 2020 or shortly thereafter. The decisions are highlighted on the map in Figure 13.3-5.

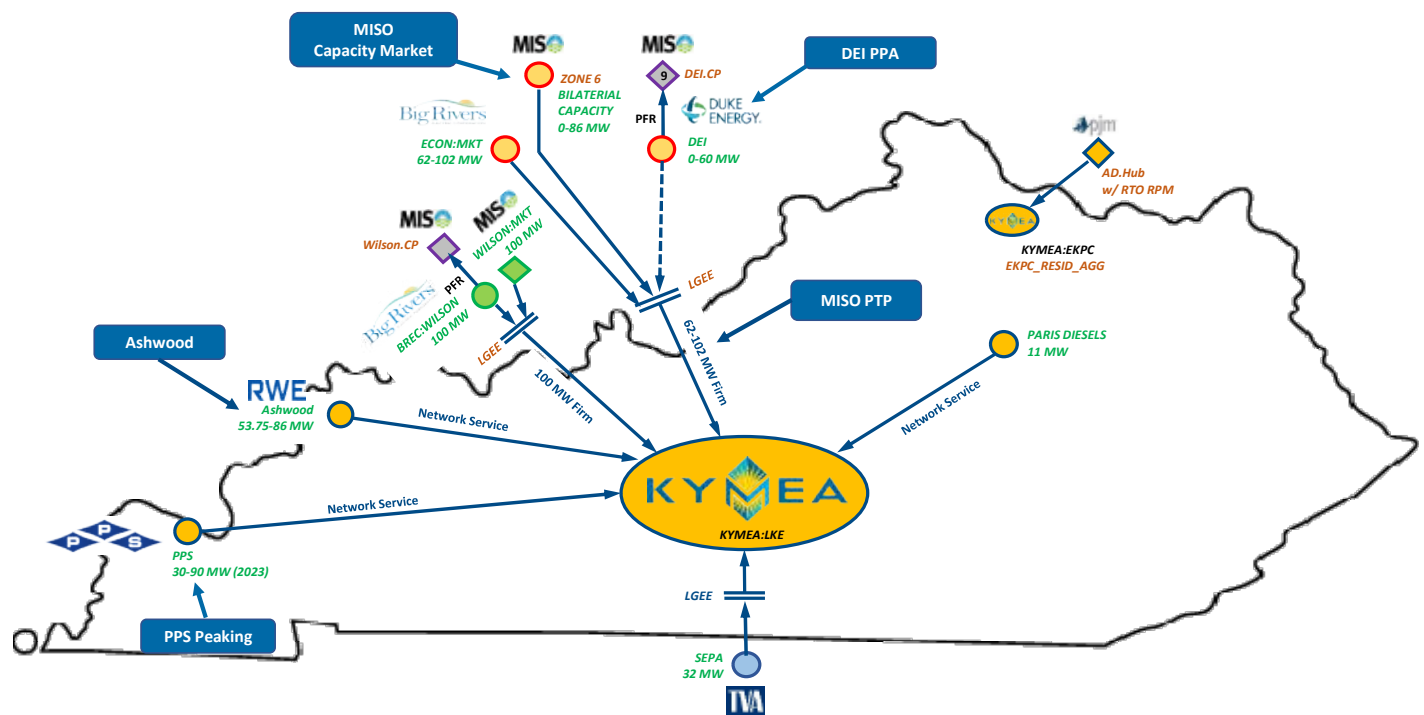


Figure 13.3-5: Near-Term Decision Elements



Develop Eleven (11) Near-Term Plan Options

The five decision elements are not mutually exclusive; as one decision element impacts another decision element. In order to address the interdependency of the decisions, eleven (11) near-term plans were created and evaluated as shown in Table 13.3-1. The analysis and results of the evaluation are described in Section 15 (Plan Evaluation) of this report.

Table 13.3-1: Near-Term Resource Plans

	Firm Capacity and Reserve Margin					Bilateral Capacity, MISO Point-to-Point Transmission, Operating Reserves				
	Planning Capacity	PPS Peaking	Ashwood Solar	DEI PPA	Reserve Margin	Bilateral Capacity	Dynamic Schedule	MISO PTP	1-in-10 Margin	Net Peak Margin
Plan A	159	30	54	0	-15.6%	79 15.2%	100 (42 min)	185 (27) 202 (40)	12.2% 18.3%	6.2% 13.2%
Plan B	159	90	54	0	7.8%	19 15.2%	100 (42 min)	162 (0) 177 (15) 202 (40)	25.5% 26.2% 39.9%	21.4% 27.6% 37.9%
Plan C	159	30	54	60	7.8%	19 15.2%	100 (42 min)	177 (15) 202 (40)	9.4% 18.3%	2.9% 13.2%
Plan D	159	45	54	45	7.8%	19 15.2%	100 (42 min)	177 (15) 202 (40)	14.7% 23.7%	9.1% 19.3%
Plan E	159	60	54	30	7.8%	19 15.2%	100 (42 min)	177 (15) 202 (40)	20.1% 29.1%	15.2% 25.5%
Plan F	159	30	86	0	-9.4%	63 15.2%	100 (67 min)	177 (15) 202 (40)	20.9% 29.9%	2.9% 13.2%
Plan G	159	75	86	0	8.2%	18 15.2%	100 (67 min)	177 (15) 202 (40)	37.1% 46.0%	21.4% 31.7%
Plan H	159	30	86	45	8.2%	18 15.2%	100 (67 min)	177 (15) 202 (40)	20.9% 29.9%	2.9% 13.2%
Plan I	159	45	86	30	8.2%	18 15.2%	100 (67 min)	177 (15) 202 (40)	26.3% 35.3%	9.1% 19.3%
Plan J	159	40	86	60	18.0%	0 18.0%	100 (67 min)	177 (15) 202 (40)	24.5% 33.5%	7.0% 17.3%
Plan K	159	60	86	30	14.1%	3 15.2%	100 (67 min)	177 (15) 202 (40)	31.7% 40.6%	15.2% 25.5%



Table Definitions

1. Planning Capacity

- BREC-Wilson: 116 MW (5/1/2019 – 5/31/2029)
 - BREC-Wilson includes 100 MW + 16 MW of reserves.
- SEPA-Hydro: 32 MW (5/1/2019 – end of hydro life)
- Paris-Diesels: 11 MW (5/1/2019 – 5/31/2029)

2. PPS Peaking

- PPS-Peakers: 90 MW (5/1/2019 – 5/31/2023)
 - Option Period: 30 to 90 MW (6/1/2023 – 5/31/2029)

3. Ashwood Solar

- Ashwood Solar I Project: 53.75 MW (12/1/2022 – 11/30/2042)
 - Right of First Refusal (RoFR): 32.25 MW

Ashwood Margin Calculations

- Planning Capacity Margin Accreditation: 50%
- 1-in-10 Operating Margin Accreditation: 100% (Summer)
- Net Peak Demand Operating Margin Accreditation: 0% (evening)

4. DEI PPA

- Duke Energy – Indiana (DEI): (6/1/2022 – 5/31/2027)
 - Option Size: 0 to 60 MW

5. Reserve Margin

- Planning Reserve Margin = Planning Capacity divided by 50/50 Peak Demand
 - Calculated for KYMEA LKE Load + Losses.



6. Bilateral Capacity

- Bilateral capacity to maintain a minimum 15% Planning Reserve Margin

7. Dynamic Schedule

- Dynamic schedule means a telemetered reading or value that is updated in real time and used as a schedule in the KYMEA Net ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes and used for scheduling from the MISO BA Area.
- Maximum dynamic schedule is 100 MW.
 - BREC-Wilson capacity supports dynamic schedule.
- Minimum dynamic schedule is 42 to 67 MW.
 - 42 MW represents two standard deviations of the 54 MW Ashwood solar intra-hour intermittency.
 - 67 MW represents two standard deviations of the 86 MW Ashwood solar intra-hour intermittency.

8. MISO PTP

- MISO point-to-point firm transmission reservation
 - 162 MW existing reservation
 - Additional increment point-to-point is noted in parentheses

9. 1-in-10 Margin

- The 1-in-10 operating margin is the operating margin calculated by the 1-in-10 peak demand. Unlike the planning reserve margin, the operating margin is calculated based upon KYMEA's ability to serve load under extreme 1-in-10 summer weather conditions.

10. Net Peak Margin

- The Net Peak Margin is the operating margin calculated by the 1-in-10 peak demand which occurs after netting solar generation against the native load requirements. The net peak margin is calculated to ensure KYMEA has adequate power and transmission resources to meet a demand that occurs later in the evening after the sun has set and solar generation is unavailable.



Benham and Berea Option

KYMEA members Benham and Berea, who are currently transmission-only members, participated in this IRP. While it is not yet known whether Benham and/or Berea will join the AR Project, the development of each plan included additional consideration and analysis to determine if the plan is flexible enough to accommodate new AR Project members if they chose to join in 2024. Described in Figure 13.3-6, Benham and Berea have a 38 MW MISO firm point-to-point transmission reservation until 4/30/2027.

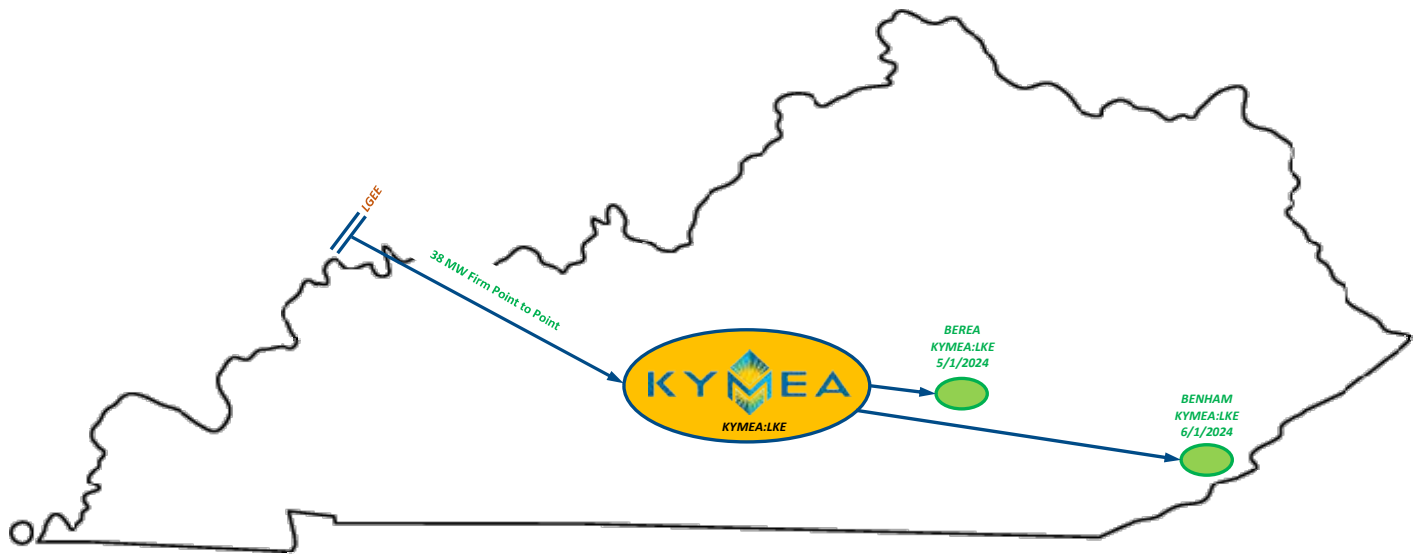


Figure 13.3-6: Benham and Berea Map



13.4 Long-Term Resource Plan

Post-2029, KYMEA focused on four long-term plans for detailed analysis. The plans were designed by KYMEA, including public participation and input, to provide unique resource mixes allowing KYMEA to consider the outcomes of plans with different types of resources. Each plan shown in Table 13.4-1 utilizes the same near-term plan through May 31, 2029. In PLAN 1 and PLAN 4, the shaded areas of the pie chart illustrate the amount of generation sold in the wholesale market.

Table 13.4-1: Long-Term Resource Plans

	Plan 1: CC Plan	Plan 2: RICE Plan	Plan 3: Market Plan	Plan 4: Net Zero Plan
Plan Description	150 MW Participation in a MISO-Sourced Combined Cycle Unit in 2029, 50 MW Solar in LKE in 2029.	156 MW LKE Reciprocating Internal Combustion Engines (RICE) in 2029, 50 MW LKE Solar in 2029.	Market Purchases. MISO-Sourced Market Bilateral Capacity and Energy. Hedge Products to manage risk.	Net Zero by 2030. 325 MW MISO-Sourced Wind in 2029, 77 MW LKE Solar. New Solar and Ashwood paired with 78 MW 10-hour Battery.
2019-2028	Same Near-Term Plans			
2029	BREC-Wilson expires, PPS-Peakers expires, Paris expires, add 150 MW CC, 50 MW Solar, 237 MW Transmission	BREC-Wilson expires, PPS-Peakers expires, Paris expires, add 156 MW RICE, 50 MW Solar, 81 MW Transmission	BREC-Wilson expires, PPS-Peakers expires, Paris expires, add 237 MW Transmission	BREC-Wilson expires, PPS-Peakers expires, Paris expires, add 327 MW Wind, 77 MW Solar, 237 MW Transmission
2030	■ Natural Gas ■ Natural Gas-Sold ■ Hydro ■ Solar ■ Market	■ Natural Gas ■ Hydro ■ Solar ■ Market	■ Hydro ■ Solar ■ Market	■ Hydro ■ Solar ■ Wind ■ Wind-Sold ■ Market
2031-2033				
2034	Add 7 MW Transmission	Add 7 MW Transmission	Add 7 MW Transmission	Add 7 MW Transmission
2035-2038				
2039	Add 7 MW Transmission	Add 7 MW Transmission	Add 7 MW Transmission	Add 7 MW Transmission
2040-2042				



Long-Term PLAN 1: Combined-Cycle (CC)

Overview: PLAN 1, illustrated in Figure 13.4-1, calls for 150 MW participation in a large advanced combined cycle unit in 2029 located in MISO Zone 6 (Indiana-Kentucky).

- **Natural Gas CC:** The 150 MW CC capacity and energy would be delivered from MISO via a firm 150 MW point-to-point transmission path. The assumed heat rate is 6,225 Btu/kWh, and the unit would not have duct-firing. In 2029, the variable operations and maintenance (VOM) is assumed as \$4.53/MWh, and the Demand Charge + fixed operations and maintenance (FOM) is assumed as \$11.30/kW-MO. Both escalate at inflation. Environmentally, the CC unit would meet all new source performance standards. It was assumed there would not be a new standard imposed for carbon capture and sequestration (CCS). The CC CO₂ emission rate is 741 lb/MWh.
- **Market Purchases:** A firm 87 MW MISO PTP path and LKE NITS would be used to deliver spot market capacity and energy purchases from MISO. Falmouth would continue to receive capacity and energy from the PJM market through PJM network transmission service. Using the Horizons Energy database, it was assumed the MISO market CO₂ emission rate is 1,014 lb/MWh and that the rate declines on average 3% per year as the MISO resource mix carbon intensity declines over time.
- **Solar:** The plan calls for 50 MW of solar in addition to the existing 54 MW Ashwood Solar I Project located in the LKE transmission area. The assumed price for the new solar facility is \$35.75/MWh in 2029 from the Horizons Energy database.
- **Hydro:** The existing 32 MW of SEPA hydro would continue to be delivered from the TVA system.

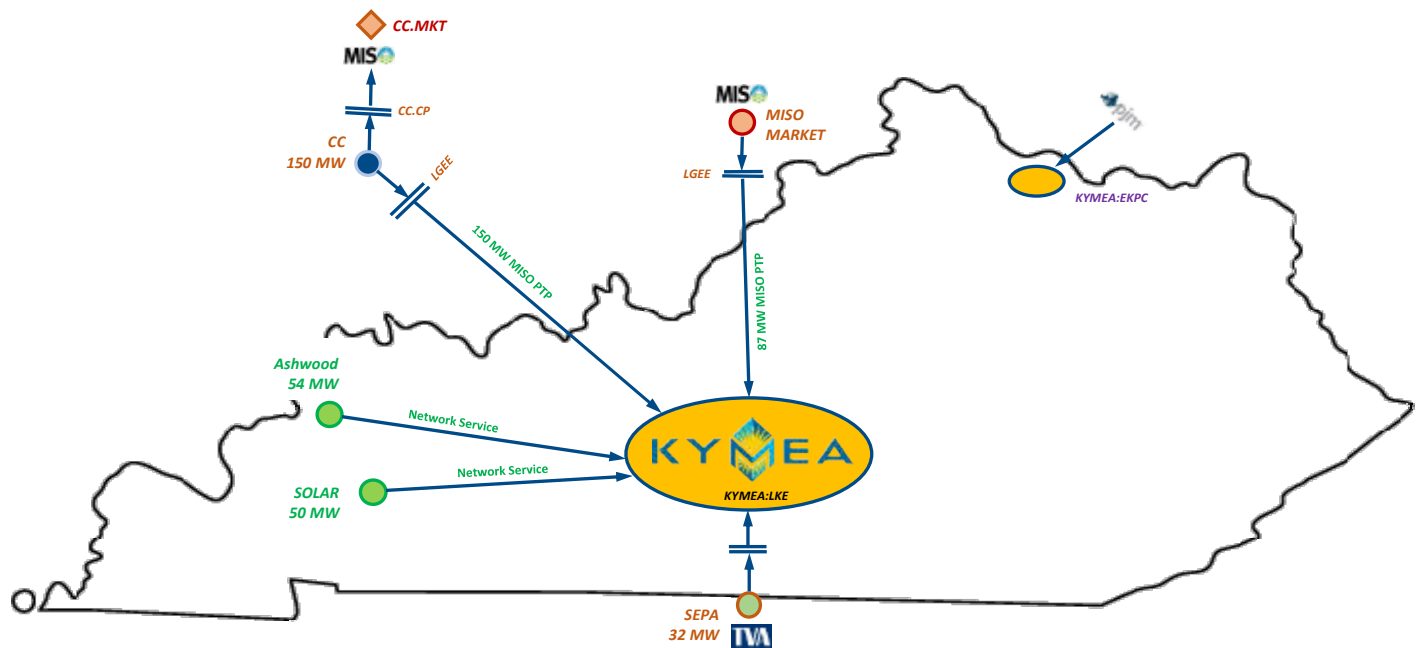


Figure 13.4-1: Long-Term PLAN 1: CC Map



Long-Term PLAN 2: Reciprocating and Internal Combustion Engine (RICE)

Overview: PLAN 2, illustrated in Figure 13.4-2, calls for 156 MW participation in reciprocating internal combustion engines (RICE) units in 2029 located in the LKE transmission system.

- **RICE:** The 156 MW RICE units would reside in the LKE transmission system. The assumed heat rate is 8,185 Btu/kWh. In 2029, the VOM is assumed as \$7.27/MWh, and the Demand Charge + FOM is assumed as \$15.46/kW-MO. Both escalate at inflation. Environmentally, the RICE units would meet all new source performance standards. It was assumed there would not be a new standard imposed for carbon capture and sequestration (CCS). The RICE CO₂ emission rate is 975 lb/MWh.
- **Market Purchases:** A firm 81 MW MISO PTP path and LKE NITS would be used to deliver spot market capacity and energy purchases from MISO. Falmouth would continue to receive capacity and energy from the PJM market through PJM network transmission service. Using the Horizons Energy database, it was assumed the MISO market CO₂ emission rate is 1,014 lb/MWh and that the rate declines on average 3% per year as the MISO resource mix carbon intensity declines over time.
- **Solar:** The plan calls for 50 MW of solar in addition to the existing 54 MW Ashwood Solar I Project located in the LKE transmission area. The assumed price for the new solar facility is \$35.75/MWh in 2029 from the Horizons Energy database.
- **Hydro:** The existing 32 MW of SEPA hydro would continue to be delivered from the TVA system.

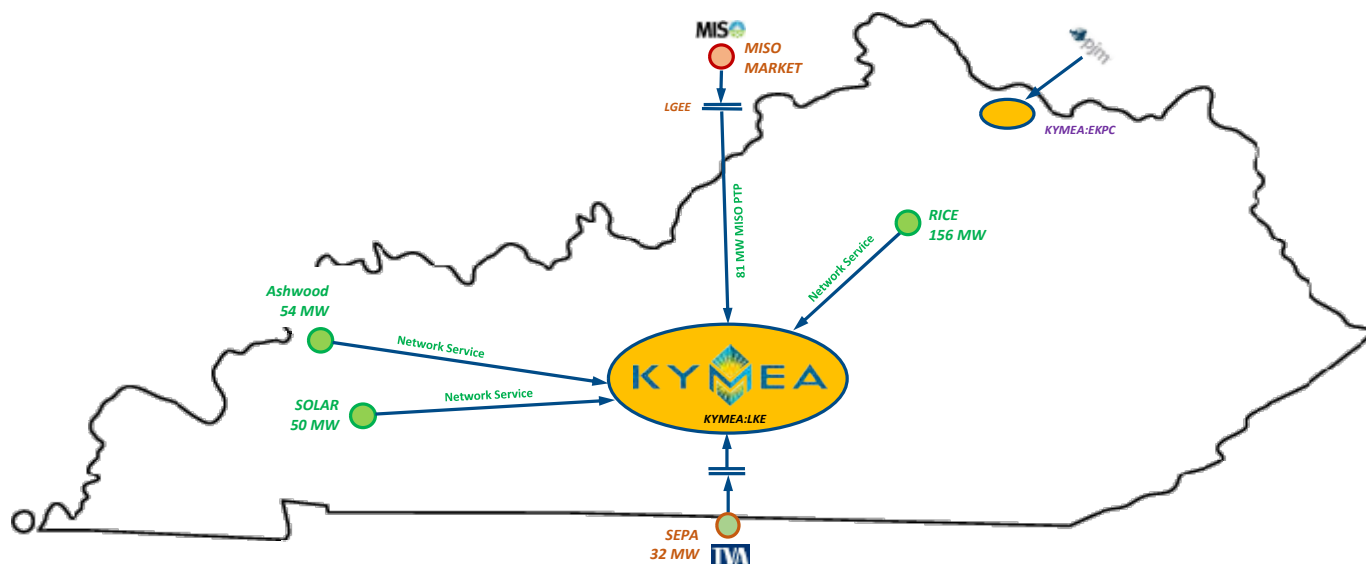


Figure 13.4-2: Long-Term PLAN 2: RICE Map



Long-Term PLAN 3: Market

Overview: Except for the 54 MW of the Ashwood Solar I Project and the 32 MW of the SEPA hydro, PLAN 3, illustrated in Figure 13.4-3, calls for only MISO and PJM market purchases beginning in 2029. Given the large market exposure of this plan, standardized 5x16 and 7x24 hedge products were assumed to off-set the market risk.

- **Market Purchases:** A firm 237 MW MISO PTP path and LKE NITS would be used to deliver spot market capacity and energy purchases from MISO. Falmouth would continue to receive capacity and energy from the PJM market through PJM network transmission service. Using the Horizons Energy database, it was assumed the MISO market CO₂ emission rate is 1,014 lb/MWh and that the rate declines on average 3% per year as the MISO resource mix carbon intensity declines over time.
- **Solar:** The plan assumes only the existing 54 MW Ashwood Solar I Project located in the LKE transmission area.
- **Hydro:** The existing 32 MW of SEPA hydro would continue to be delivered from the TVA system.

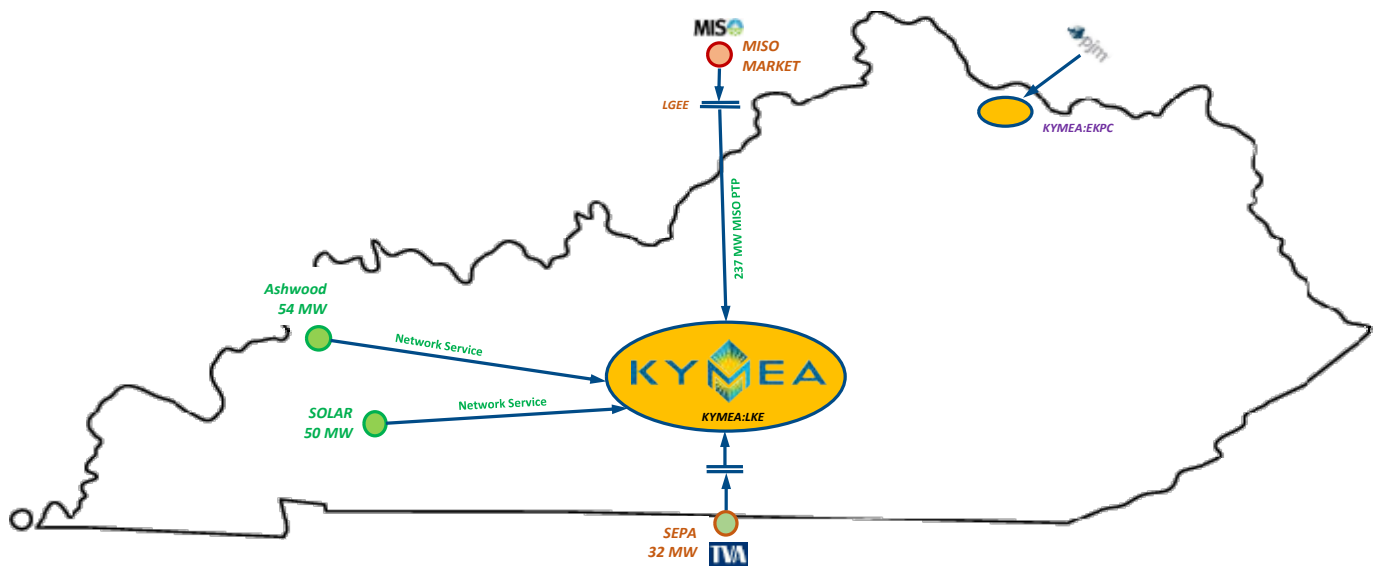


Figure 13.4-3: Long-Term PLAN 3: Market Map



Long-Term PLAN 4: Net Zero

Overview: PLAN 4, illustrated in Figure 13.4-4, calls for 325 MW participation in a large wind farm in 2029 located in MISO Zone 6 (Indiana-Kentucky) and 77 MW of new solar in LKE in 2029. KYMEA's solar (Ashwood + new solar) would be paired with 78 MW of battery storage. In this plan, KYMEA would be carbon neutral by 2030.

- **Wind:** The 325 MW wind capacity and energy would be delivered from MISO via a firm 237 MW MISO PTP path with LKE NITS. The path is sized to provide the wind necessary to serve the KYMEA native load. Any excess wind is sold into MISO and treated as a carbon off-set to achieve carbon neutrality on an annual basis. The assumed price for the new wind facility is \$37.07/MWh in 2029 from the Horizons Energy database.
- **Solar:** The plan calls for 77 MW of solar in addition to the existing 54 MW Ashwood Solar I Project located in the LKE transmission area. The assumed price for the new solar facility is \$35.75/MWh in 2029 from the Horizons Energy database. The new solar facility would be paired with 4-hour, 312 MWh lithium-ion battery energy storage systems which are charged and discharged at a rate of 78 MW. The assumed price of the 4-hour battery is \$27.22/kW-MO with a cycle life of 2100. The cost of replacing the batteries, after ten years of life, is assumed to decline 10% as the battery technology and costs improve.
- **Hydro:** The existing 32 MW of SEPA hydro would continue to be delivered from the TVA system.

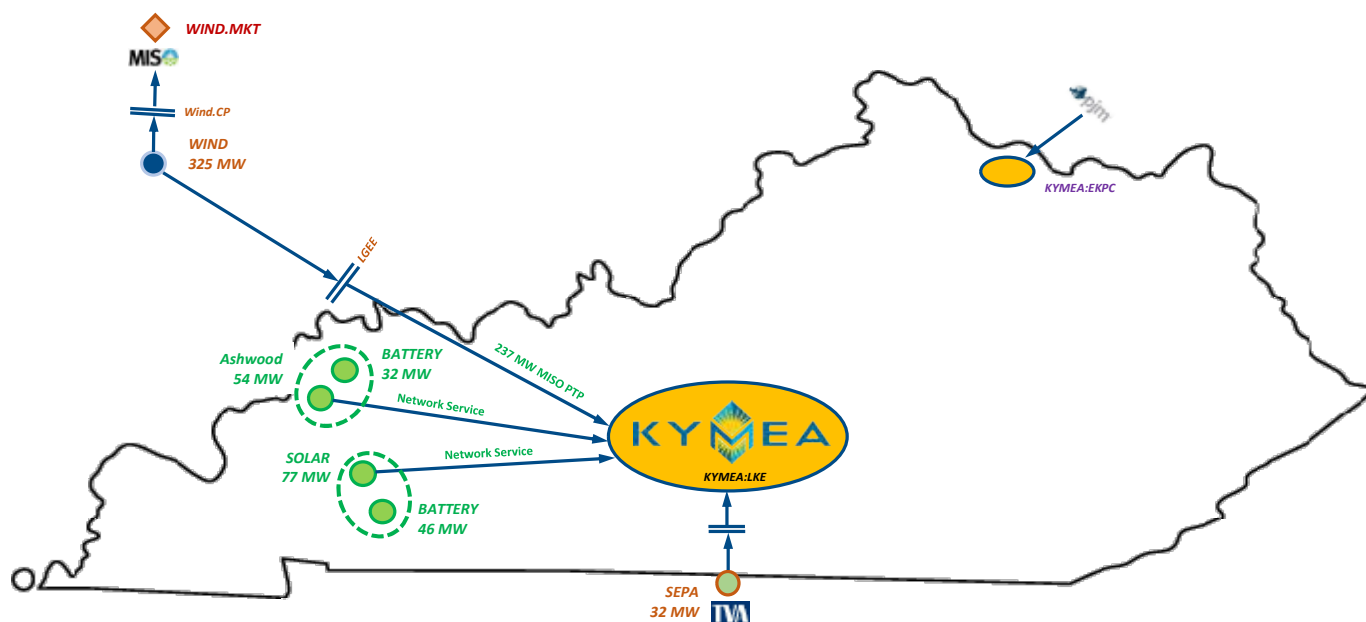


Figure 13.4-4: Long-Term PLAN 4: Net Zero Map



Battery Storage

The Net Zero Plan adds 312 MWh of battery storage (4-hours at 78 MW per hour) paired with two solar installations. As shown in Figure 13.4-5, battery storage has a wide variety of applications. On the left-hand side of the dial (red area), batteries can be used for frequency regulation and intra-hour smoothing of solar intermittency. On the right-hand side of the dial, battery storage is used to offset peaking generation and MISO firm transmission. The most predominant battery technology today is 2-to-4-hour batteries, which is suited for renewable smoothing, operating reserves, and load following.

For the Net Zero Plan, KYMEA modeled 78 MW of 4-hour batteries to offset peaking capacity and MISO firm transmission needs.



Figure 13.4-5: Battery Energy Storage Applications



13.5 Decarbonization

President Biden's goal of a 100% carbon-free power sector by 2035 presents a daunting challenge as 100% carbon-free requires the elimination of all fossil generation. Today, roughly 62% of the U.S. generation comes from fossil energy sources, and another 19% comes from nuclear generation. As nuclear generation struggles to remain economically viable, there is expected to be an even greater carbon-free void to fill due to the considerable amount of carbon-free nuclear retirements.

Many in the power industry, including advocates for aggressive carbon reduction, are urging the President and members of Congress to be pragmatic about the road to carbon-free power and carefully consider the current technology limitations and financial and reliability ramifications of moving too far, too fast.

The devastating week-long ERCOT power outage due to the February 2021 Polar Vortex provides a stark reminder of how important energy reliability is on the journey to carbon-free power and that multiple sources of energy, including fossil fuel will likely remain an important part of the resource mix.

To understand the feasibility and cost of KYMEA becoming fully decarbonized by 2035, the Agency created two resource plans that are fully decarbonized. Fully decarbonized is different than net zero. While both are carbon free on an annual basis, the fully decarbonized plans do not rely on fossil fuels to balance the system; but rather use storage to balance supply and demand.

- **PLAN 5:** Solar + Battery Storage + Hydro
- **PLAN 6:** Solar + Wind + Battery Storage + Hydro

Long-Term PLAN 5: Solar + Battery Storage + Hydro

A decarbonization plan which consists of solar, battery storage, and SEPA hydro is shown below. PLAN 5, illustrated in Figure 13.5-1, calls for 1,693 MW of batteries to be added to the 54 MW Ashwood Solar I site. An additional five (5) sites would be developed, pairing 130 MW of solar with 4,063 MW of 10-hour batteries at each site. The total amount of solar is 702 MW, and the total amount of batteries is a staggering 22,008 MW.

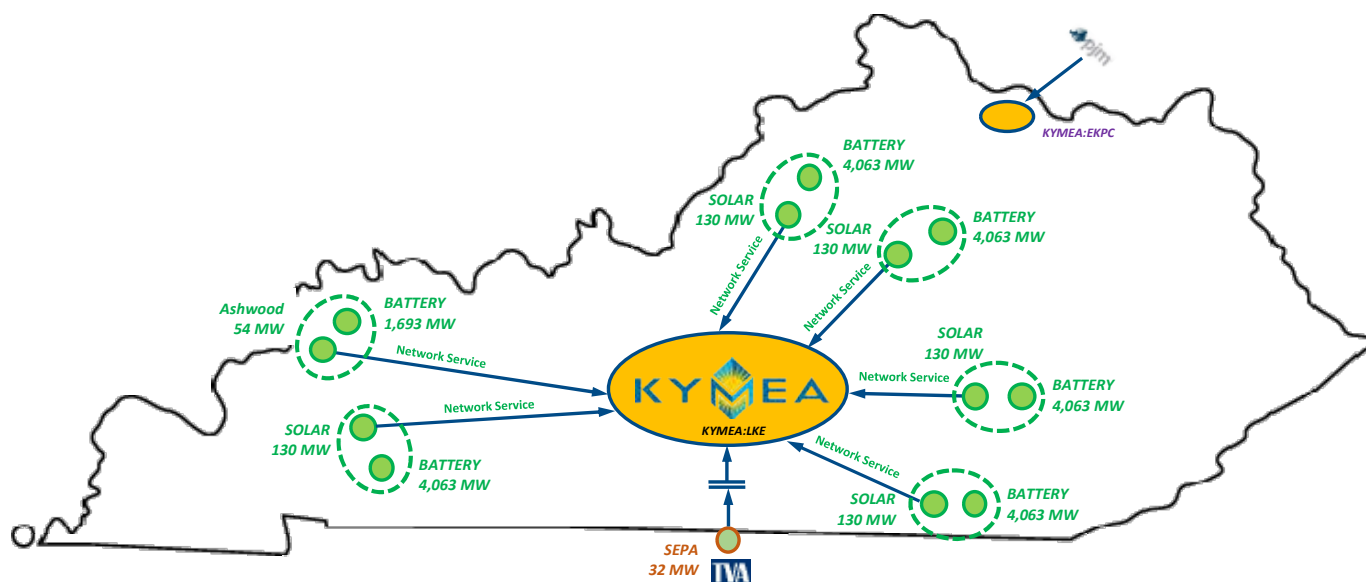


Figure 13.5-1: Long-Term PLAN 5: Solar + Battery + Hydro Map



Battery Storage Level

Adding 22,008 MW of batteries provides 220,080 MWh of storage (22,008 MW x 10 hours). The question of why 220,080 MWh of storage is necessary is quickly raised. The answer lies in the simple fact the sun does not always shine, does not shine at night, and far less solar output occurs in the winter. As per limitations of lithium-ion batteries, and to maintain storage reserves, a minimum of a 20% charge is maintained in the batteries at all times.

The Battery Storage Level Figure 13.5-2 illustrates the storage maintained throughout the year.

- On January 1, the battery storage level needs to be nearly 100,000 MWh. The 100,000 MWh of stored energy, coupled with winter-time solar generation output, provides enough energy to serve the load requirements to the end of the winter season.
- In the spring, increased solar output coupled with lower loads due to mild weather, allows KYMEA to begin recharging the batteries. At this point, the stored energy is at its lowest level. During years with very harsh and overcast winters, this time of year could be a problem.
- From spring to fall, the 702 MW of solar both meets the hourly load requirements and recharges the massive number of batteries in preparation for the winter.
- By mid-October, the storage is filled and available for the upcoming winter.
- As shown in the figure, the goal is to end the year with nearly 100,000 MWh in storage and then begin the annual storage cycle anew.

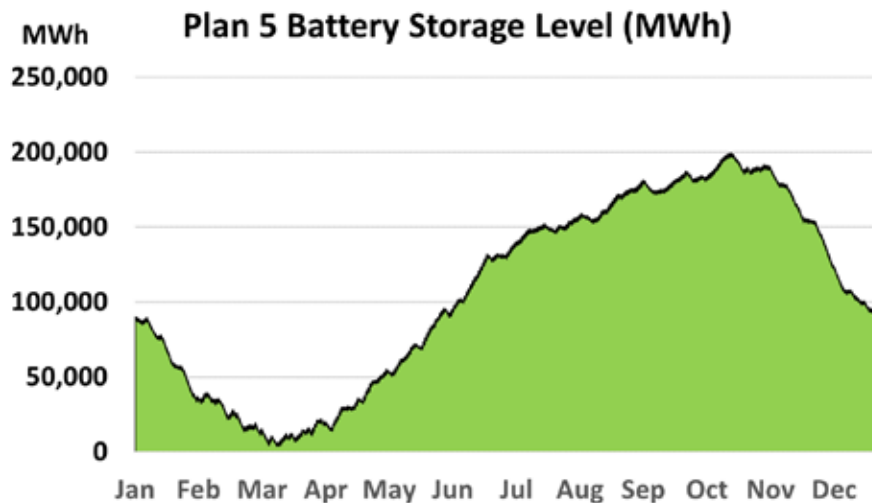


Figure 13.5-2: Long-Term PLAN 5: Battery Storage Level (MWh)



Figure 13.5-3 illustrates that 55% of the resource needs is met by solar energy that is stored in batteries and released throughout the year.

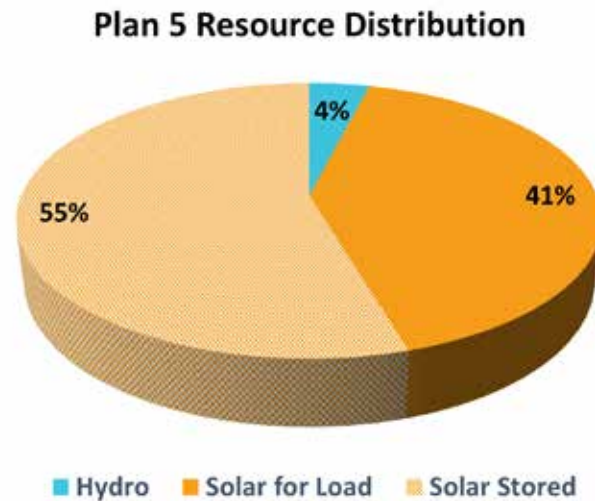


Figure 13.5-3: Long-Term PLAN 5: Resource Distribution

Plan Cost

A plan that consists solely of Solar + Battery Storage + SEPA can be summed up as perhaps feasibly possible, but financially impractical with today's battery technology. Even with the expected steep decline in battery prices, this plan is a complete non-starter.

By 2035, the annual production expense of 702 MW of solar coupled with 22,008 MW of 10-hour lithium-ion batteries and 32 MW of SEPA would be \$13.2B dollars. This is over 100 times the expected annual cost in 2035 and would raise the expected average system rate from \$75 per MWh to a nonsensical \$9,000 per MWh.



Long-Term PLAN 6: Wind + Solar + Battery Storage + Hydro

A decarbonization plan which consists of Wind, Solar, Battery Storage, and SEPA Hydro is shown in Figure 13.5-4. The plan calls for 824 MW of batteries to be added to the 54 MW Ashwood Solar I site. An additional two (2) solar sites would be developed, pairing 122 MW of solar with 1872 MW of 10-hour batteries at each site. A 250 MW wind site located in MISO, where there is an adequate wind supply at 100 meters, would be developed and paired with 3,827 MW of 10-hour batteries. A 244 MW firm point-to-point transmission tie to MISO would provide delivery of the wind + battery storage energy. The total amount of solar is 298 MW, 250 MW of wind, 8,395 MW of batteries, and 32 MW of hydro. The mix of wind and solar was optimized to minimize the number of batteries required, since batteries are the most expensive component of the plan.

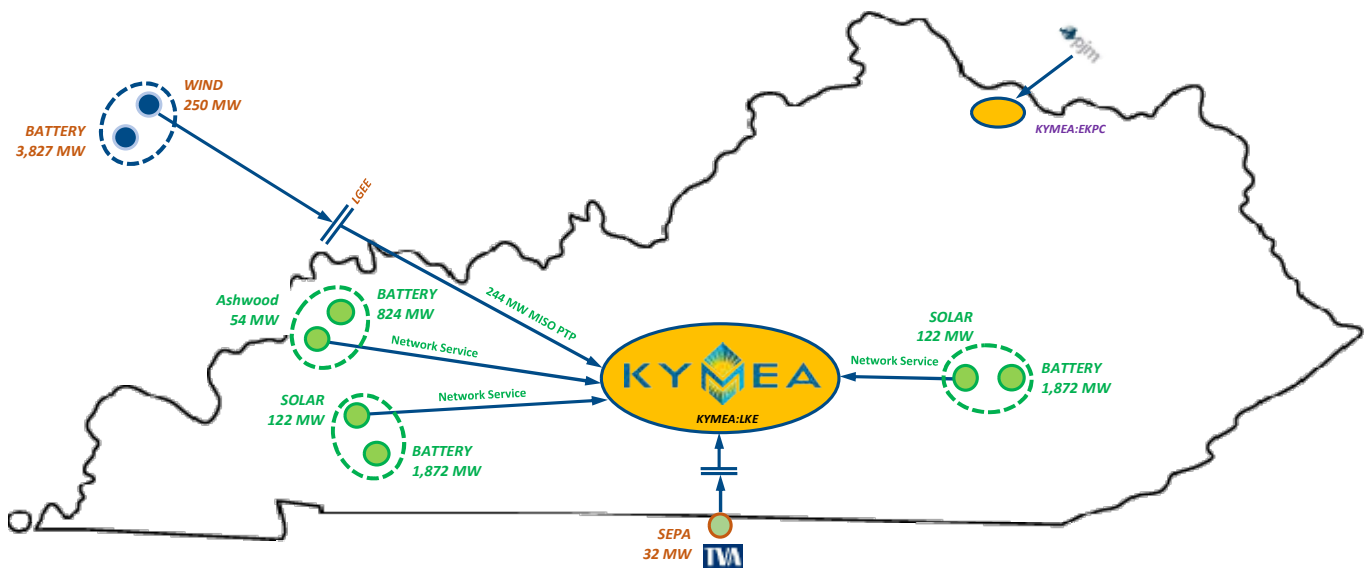


Figure 13.5-4: Long-Term PLAN 6: Wind + Solar + Battery Storage + Hydro Map



Battery Storage Level

Adding wind to the mix provides an around-the-clock energy supply; however, there are still huge storage needs to meet the load requirements over the course of a year. The 8,395 MW of batteries provides 83,950 MWh of storage (8,395 MW x 10 hours). As per limitations of lithium-ion batteries, and to maintain storage reserves, a minimum of a 20% charge is maintained in the batteries at all times.

The Battery Storage Level, Figure 13.5-5, illustrates the storage maintained through-out the year.

- On January 1, the battery storage level needs to be nearly 52,000 MWh. The 52,000 MWh of stored energy, coupled with winter-time solar and wind generation output, provides enough energy to serve the load requirements to the end of the winter season.
- Beginning in mid-April, the battery storage reaches its lowest level. At this point, there is sufficient excess wind and solar to begin recharging the batteries.
- By mid-October, a 2nd low storage point occurs.
- As shown in the figure, the goal is to end the year with nearly 52,000 MWh in storage and then start the annual cycle anew.

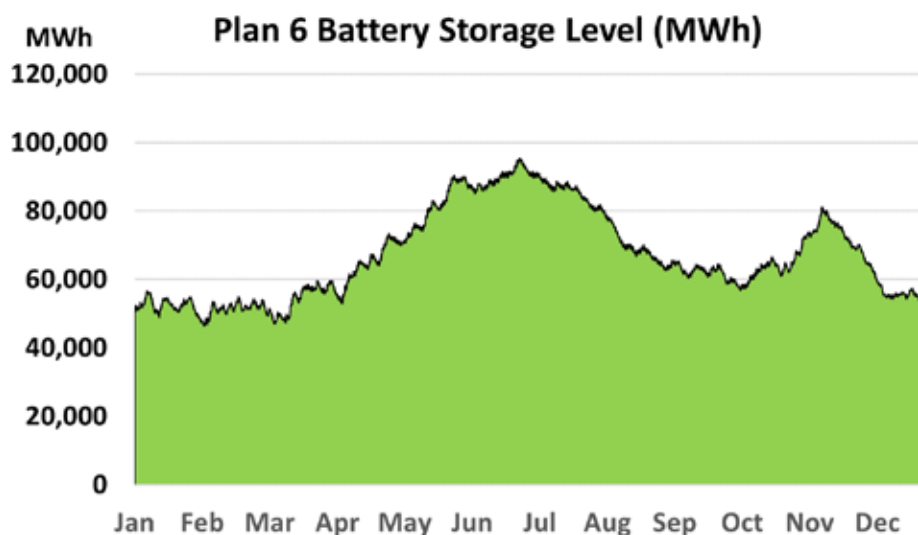


Figure 13.5-5: Long-Term PLAN 6: Battery Storage Level (MWh)



Figure 13.5-6 illustrates that 17% and 13% of the resource needs is met by solar energy and wind energy, respectively, that is stored in batteries and released throughout the year.

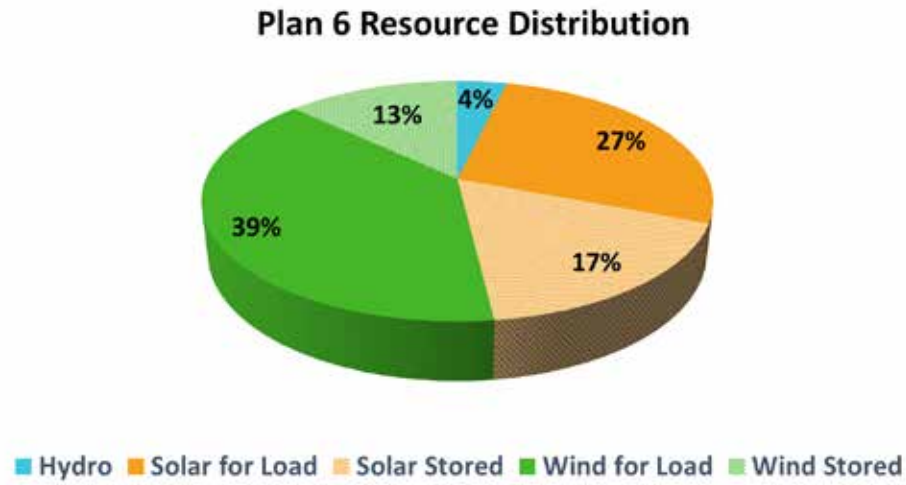


Figure 13.5-6: Long-Term PLAN 6: Resource Distribution

Plan Cost

By 2035, the annual production expense of PLAN 6 is \$5B dollars. This would raise the expected average system rate from \$75 per MWh to an unreasonable \$3,433 per MWh. The massive increase in cost is driven by the fact 8,395 MW of 10-hour batteries are needed to provide enough storage.



13.6 Distributed Energy Resources (DER)

Member Net-Metering

Other than emergency generators for water treatment plants and the like, KYMEA has very little customer-owned generation connected to its member systems. There are approximately 30 net metering installations totaling 1,725 kW across the AR Project members listed in Table 13.6-1.

Table 13.6-1: KYMEA Member Net Metering Customers

Member	Residential Net Meter Customers	Residential Net Meter kW	Commercial Net Meter Customers	Commercial Net Meter kW	Industrial Net Meter Customers	Industrial Net Meter kW	Total Net Meter kW
Barbourville	1	16.00	0	0.00	1	80.00	96.00
Bardwell	0	0.00	0	0.00	0	0.00	0.00
Corbin	2	10.00	1	10.00	0	0.00	20.00
Falmouth	0	0.00	0	0.00	0	0.00	0.00
Frankfort	15	149.02	8	419.68	4	1,000.00	1,568.70
Madisonville	1	7.00	2	33.00	0	0.00	40.00
Paris	0	0.00	0	0.00	0	0.00	0.00
Providence	0	0.00	0	0.00	0	0.00	0.00
Total	19	182.02	11	462.68	5	1,080.00	1,724.70

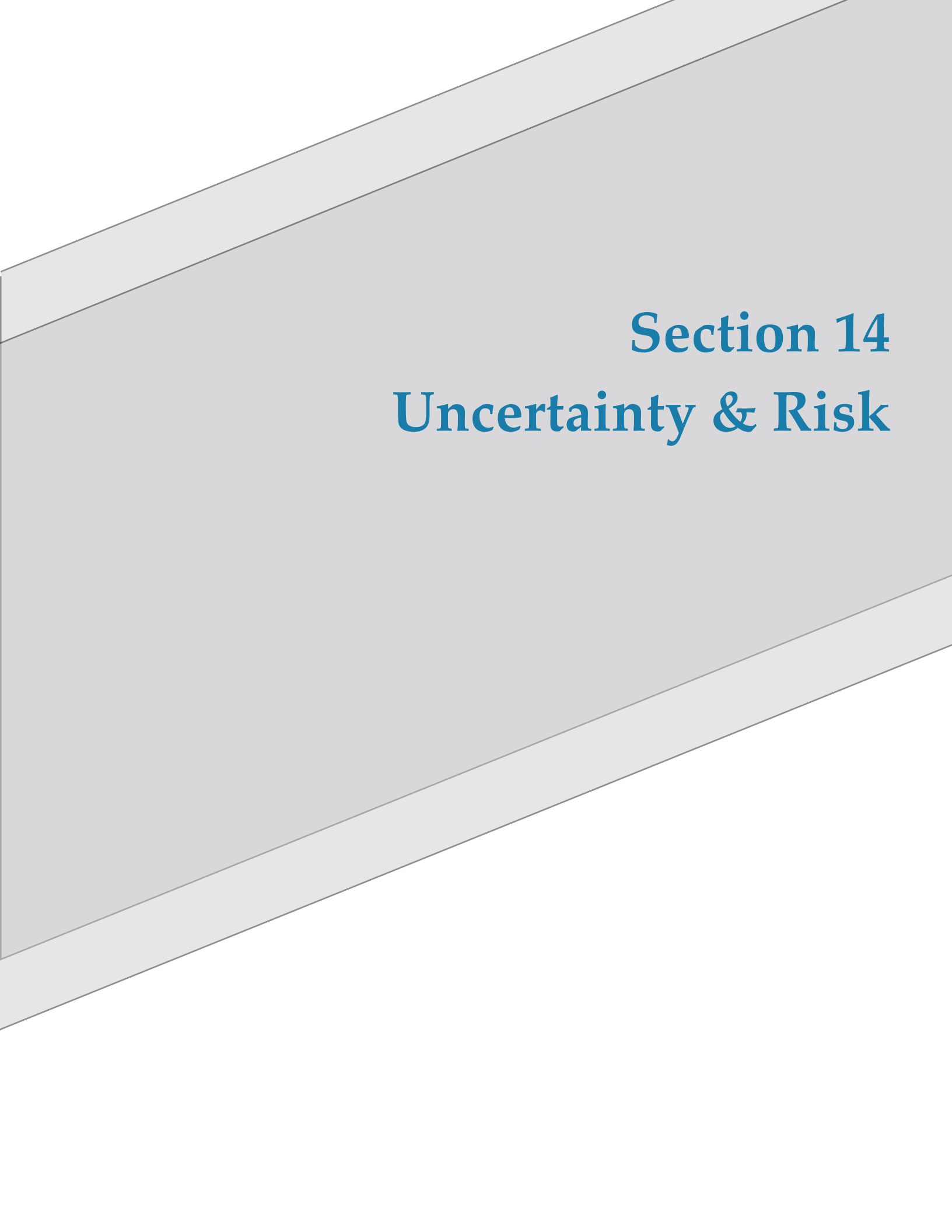
Member Combined Heat and Power

KYMEA does not currently have any customers on the system that operate a CHP system. Since a CHP or customer-owned generation system is a very site-specific resource that is completely dependent on having a heating load customer, KYMEA did not model an expansion unit to represent these systems. Going forward, KYMEA will work with its members and their customers to investigate the addition of CHP or renewable systems at customer locations if proper conditions arise.



13.7 Demand-Side Options

For the IRP2020, no specific DSM programs were developed. In the future, the most cost-effective DSM programs will be programs which reduce KYMEA's peak demand requirements. KYMEA is not directly responsible for managing relationships with the retail customers served by its members - relationships with retail customers are managed by the members. KYMEA is in a position to support members in evaluating and developing demand-side programs. KYMEA would then rely on demand-side programs in planning future power supply portfolios as commitments are made by members and the members' customers to those programs. Overall, KYMEA has substantial flexibility to adapt future power supply portfolios if and as new demand-side options are identified and implemented at the member level.



Section 14

Uncertainty & Risk

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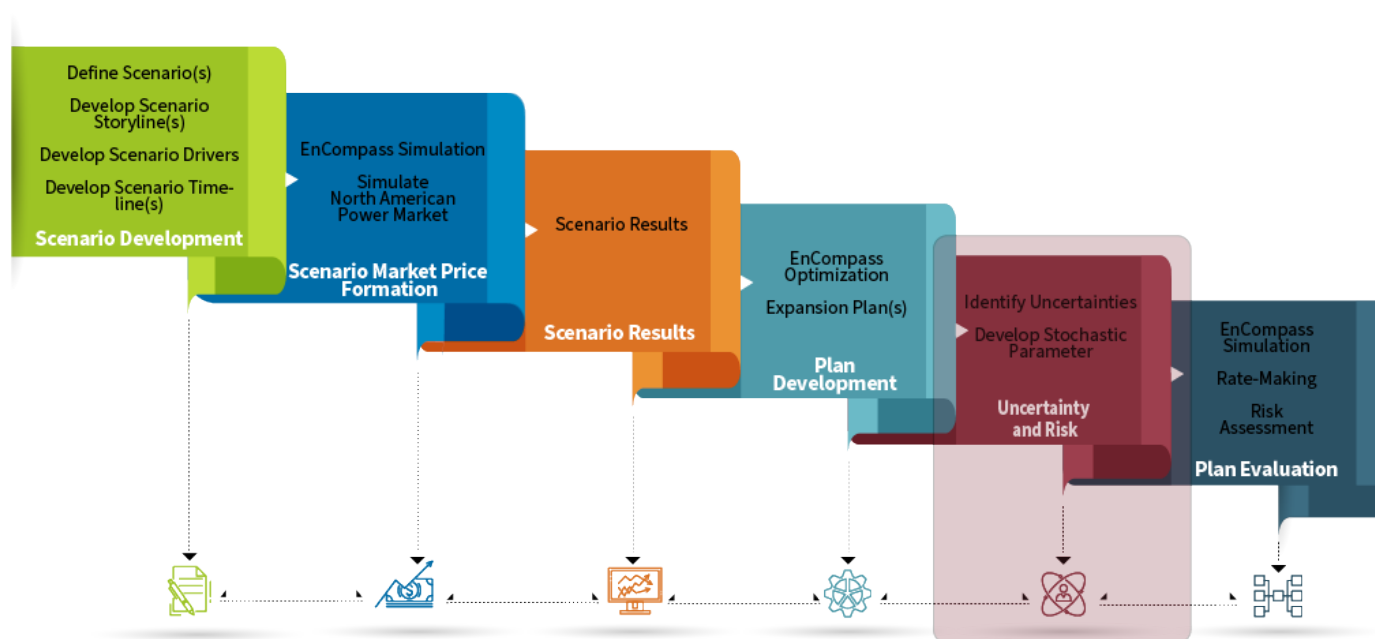


14. UNCERTAINTY & RISK

14.1 Measuring Risks

Prior to the detailed EnCompass model simulation of each plan, which occurs in Section 15 Plan Evaluation, KYMEA categorized and evaluated the various types of uncertainties and risks. This section of the report, Uncertainty and Risk, discusses the types of risk KYMEA considers.

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Risk Analysis Quadrants

The risk analysis quadrants considered by KYMEA in Figure 14.1-1 are those of sensitivity analysis, scenario analysis, stochastic analysis, and stress analysis.

- **Sensitivity Analysis:** Sensitivity analysis is single variable analysis to assess the impact of a variable on a portfolio.
- **Scenario Analysis:** Scenario analysis is a process of analyzing future events by considering possible alternative outcomes. Scenario analysis does not try to show one exact picture of the future, instead it presents several alternative future developments. In contrast to stochastic analysis, scenario analysis is not based on statistical past data or trends.
- **Stochastic Analysis:** Stochastic analysis is multi-variable analysis that is randomly determined. Outcomes have a random probability distribution or pattern that may be analyzed statistically but may not be predicted precisely.
- **Stress Analysis:** Stress analysis considers low probability, high impact events. These events can cause severe financial and/or reliability concerns.



Figure 14.1-1: Risk Analysis Quadrants



14.2 Near-Term Plan Selection - Sensitivity Analysis

Sensitivity analysis, also known as "what-if" analysis, involves examining what happens to a plan when changes are made in a key assumption on which it is based. For the eleven (11) near-term plans identified in Section 13, KYMEA tested the sensitivity of the plans with high-base-low natural gas, energy price, and capacity price sensitivities as illustrated by the decision tree in Figure 14.2-1. The overall exposure to the market was also tested with a “No Market” sensitivity case.

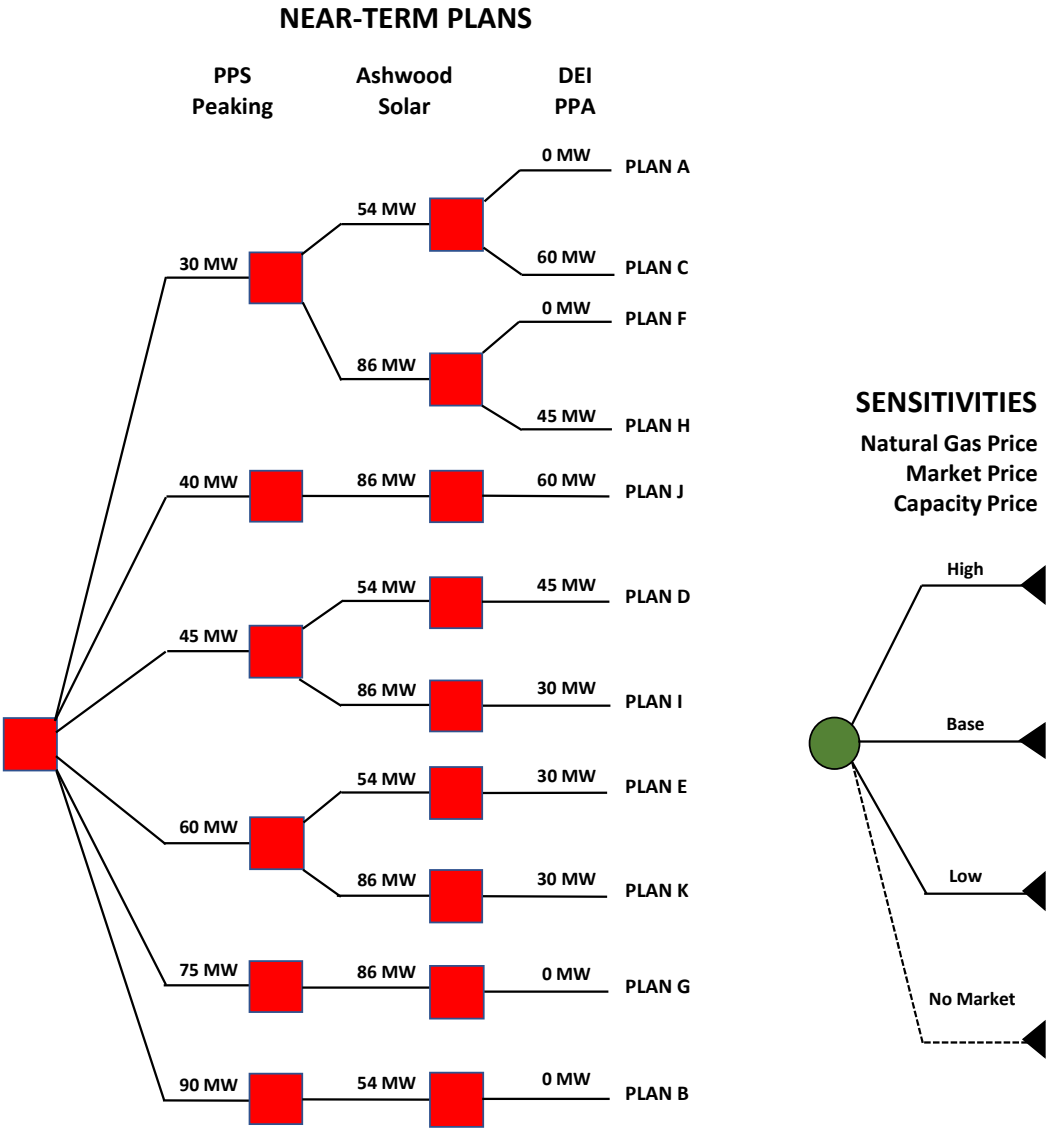


Figure 14.2-1: Near-Term Plan Decision Tree with Sensitivity Analysis



Natural Gas Price Sensitivity

The base natural gas price forecast was based on the August 27, 2020, forward curve. The high and low sensitivities shown in Figure 14.2-2 were from the Horizons Energy Spring 2020 Scenario Service (High NG and Low NG). The High NG forecast is 35% greater than the base case, while the Low NG forecast is 41% less than the base case.

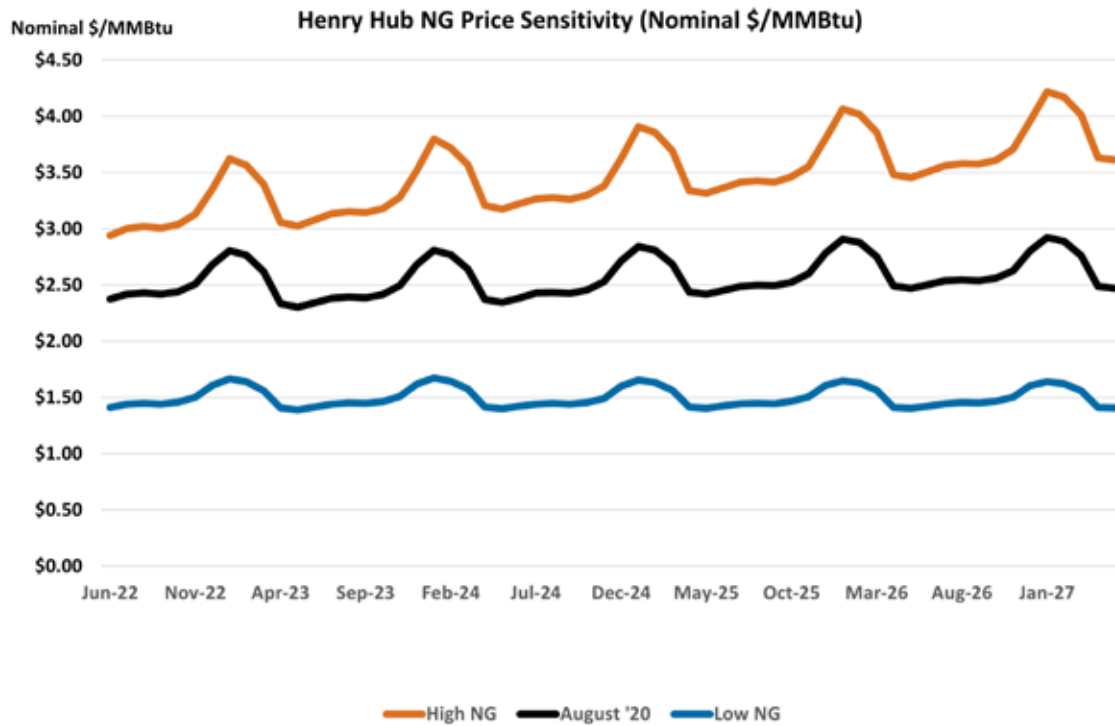


Figure 14.2-2: Henry Hub NG Gas Price Sensitivity (nominal \$/MMBtu)



Energy Price Sensitivity

The base LGEE around-the-clock (ATC) price forecast was based on the August 27, 2020, forward curve for Indy.Hub, basis adjusted to the LGEE interface point to depict the MISO energy price that would be available to KYMEA. The high and low sensitivities shown in Figure 14.2-3 were from the Horizons Energy Spring 2020 Scenario Service (High NG and Low NG) for the MISO-IN-KY price point, basis adjusted to the LGEE interface point. The High LGEE forecast is 18% greater than the base case, while the Low LGEE forecast is 26% less than the base case.

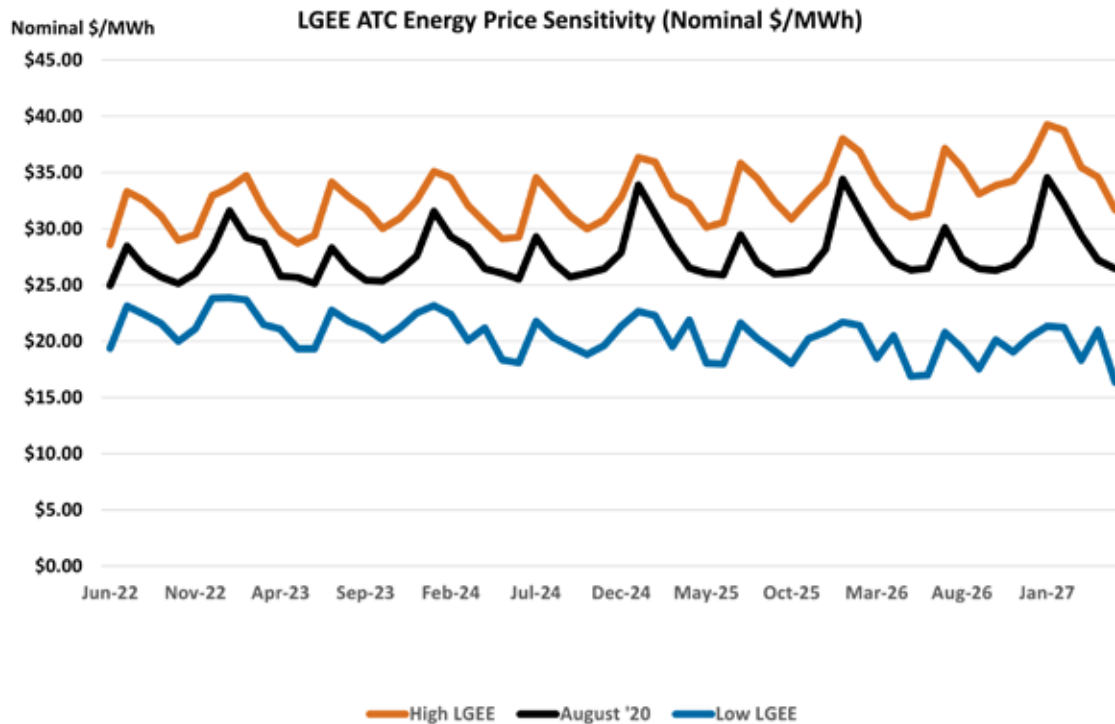


Figure 14.2-3: LGEE ATC Energy Price Sensitivity (nominal \$MWh)

The basis adjustment from the MISO-IN-KY zonal price point to the LGEE nodal price point is described in Section 11 of this report.



Capacity Price Sensitivity

The base bilateral capacity price forecast was based on market intelligence gathered by KYMEA. In Figure 14.2-4, the high sensitivity case was tied to the MISO IMM proposed sloped demand curve as described in Section 11 of this report. The low sensitivity case was based on the MISO PRA offer curve conduct threshold level cap. The conduct threshold level cap is 10% of the cost of New Entry (CONE). Offers under the threshold level are not subject to the IMM review for physical and economic withholding.

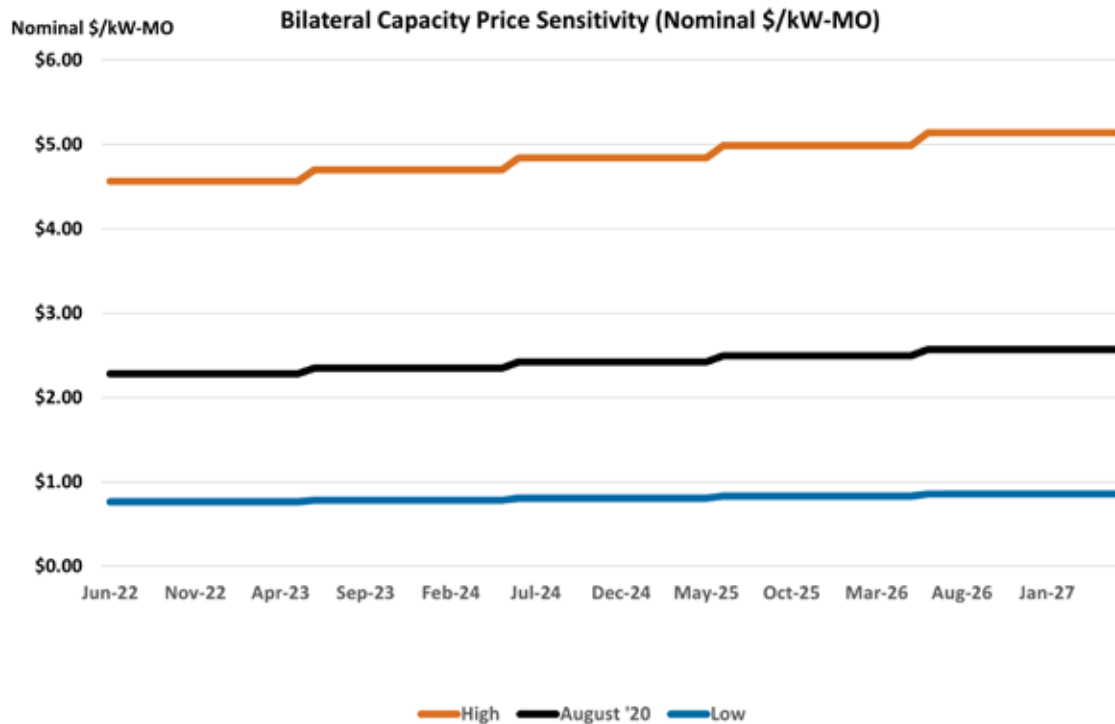


Figure 14.2-4: Bilateral Capacity Price Sensitivity (nominal \$/kW-MO)



14.3 Long-Term Plan Selection - Scenario Analysis

In Sections 10-12, and shown in Figure 14.3-1, the IRP2020 report describes the Horizons Energy nine plausible scenarios of the future. For each of the four long-term resource plans developed in Section 13, the nine scenarios were simulated to evaluate the robustness and performance across alternate futures.

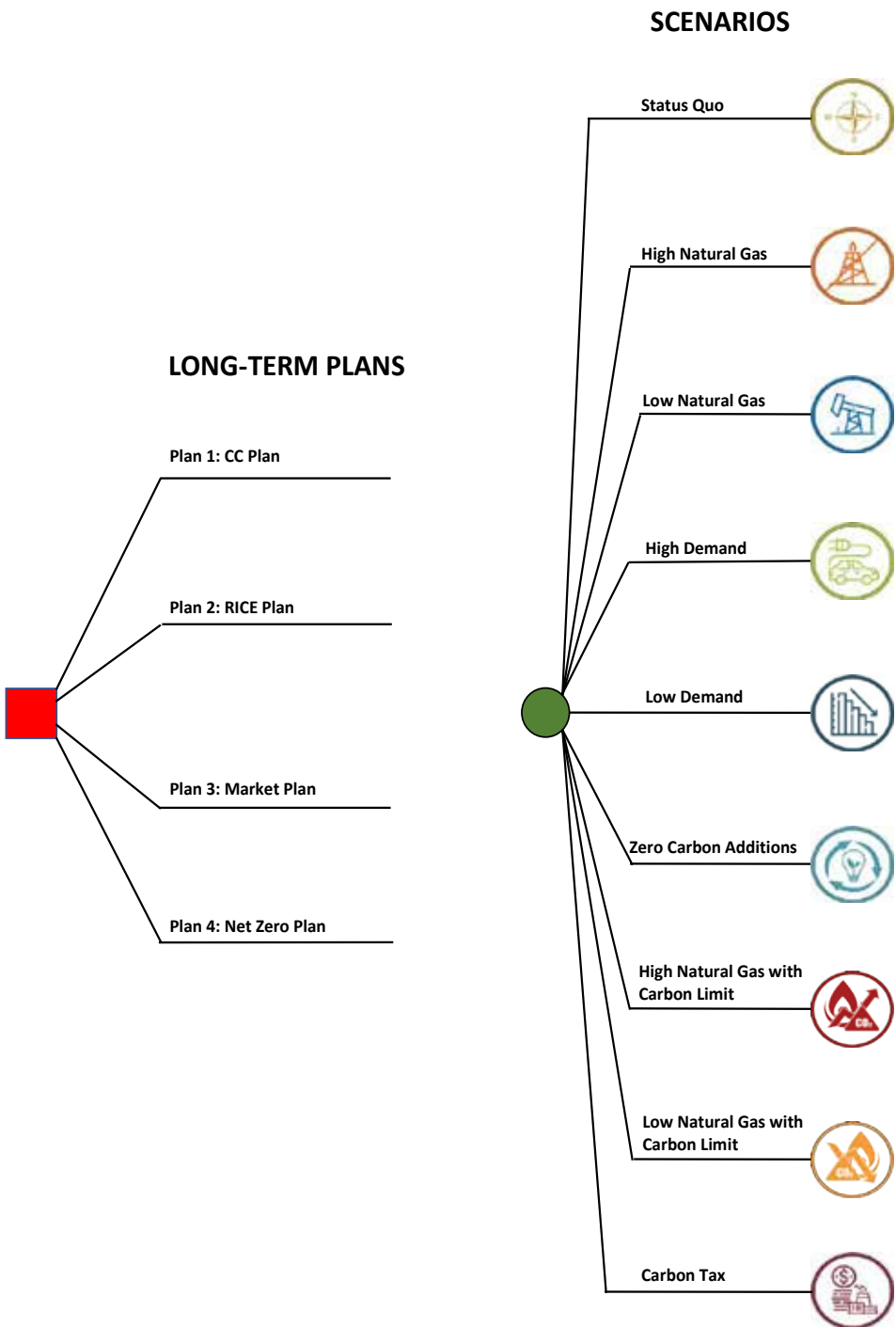


Figure 14.3-1: Long-Term Plan Decision Tree with Scenario Analysis



14.4 Selected Plan Hedging - Stochastic Analysis

KYMEA manages its portfolio through its enterprise-wide risk management (ERM) program, using market instruments to hedge the portfolio when appropriate.

Stochastic Analysis

The ERM program begins by modeling the risks through stochastic analysis. In probability theory, a stochastic or random process is a mathematical object defined as a family of random variables. In market simulation models such as EnCompass, the stochastic drivers can be represented by time series variables which become model inputs. To quantify and assess the uncertainty of the power markets and KYMEA's portfolio, the stochastic process includes many related random variables. Unlike sensitivity analysis that considers the impact of a single variable, the stochastic process considers sets or families of variables. By design, each family of variables has an equal probability of occurrence.

Latin Hypercube Sampling

A well-known statistical technique for capturing random variables is Monte Carlo simulation. The Monte Carlo simulation makes draws from a sample space to predict the probability of different outcomes when random variables are present.

The downside of Monte Carlo for market simulation and portfolio models is the sheer number of simulations that must be performed to accurately cover the number of possible outcomes. If too few simulations are made, the random draws may not cover the entire distribution of outcomes, leaving holes in the analysis.

A preferred technique for power simulation models is to use a stratified Monte Carlo sampling technique, which is referred to as Latin Hypercube Sampling (LHS). The Latin hypercube generates multiple stochastic futures (families). The draws are driven by variations in a host of market price and portfolio "drivers" (e.g., demand, fuel price, unit availability, hydro output, capital expansion cost, transmission availability, reserve margin, emission price, weather, etc.) and consider statistical distributions, correlations, and volatilities.



LHS can be thought of as “smart” Monte Carlo sampling. Instead of drawing each sample from the entire distribution – as in Monte Carlo sampling – the sample space is divided into equal probability ranges, and a sample is taken from each range. As illustrated by Figure 14.4-1, the probability density function (PDF) is divided into equally spaced divisions. The Latin hypercube makes a draw from each division which ensures the entire sample space is covered.

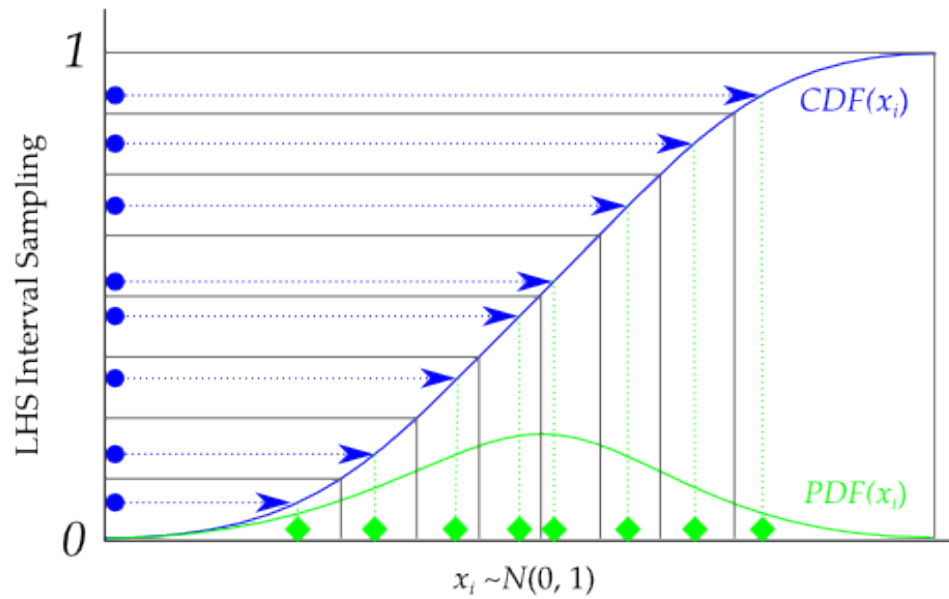


Figure 14.4-1: Latin Hypercube Density Function



In order to develop the family of drivers for EnCompass, the Latin hypercube uses a statistical method for generating a random sample of parameter values from a multidimensional distribution. In the context of statistical sampling, a square grid containing sample positions is a Latin square if (and only if) there is only one sample in each row and each column as illustrated by the probability density functions in Figure 14.4-2. Sampling each row and column ensures the range of outcomes is analyzed with as few simulations as needed to cover the sample space.

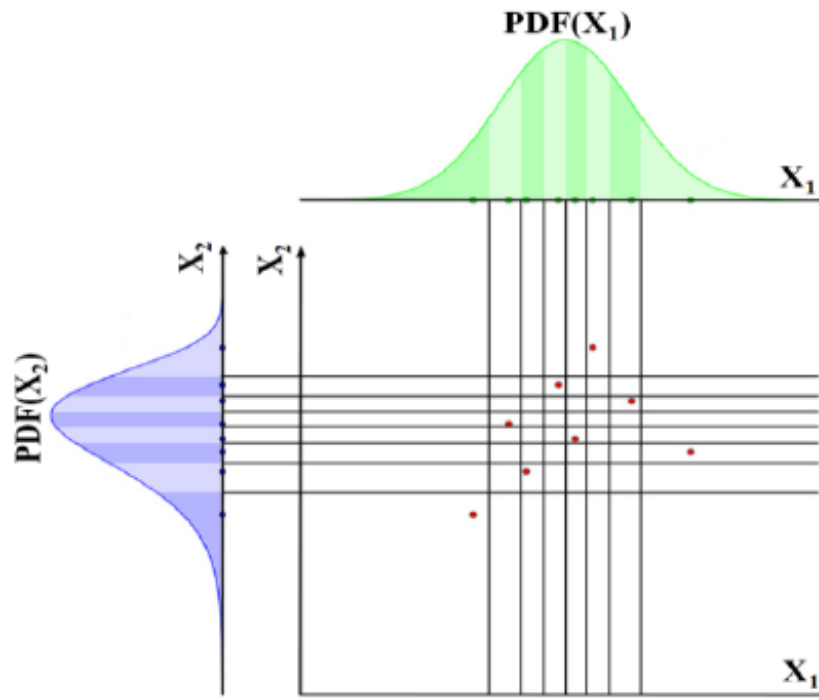


Figure 14.4-2: Latin Hypercube Sampling for Two Variables



Statistical Measures

Probability and statistics are the two important concepts. Probability is all about chance, whereas statistics is how one handles the data.

- Probability denotes the possibility of the outcome of any random event. The meaning of this term is to check the extent to which any event is likely to happen.
- Statistics is the collection, analysis, interpretation, presentation, and organization of data. It is a method of collecting and summarizing the data.

The following list is the statistical measures and concepts KYMEA applies when making the Latin hypercube draws. Figure 14.4-3 illustrates and explains the various statistical measures of a probability distribution.

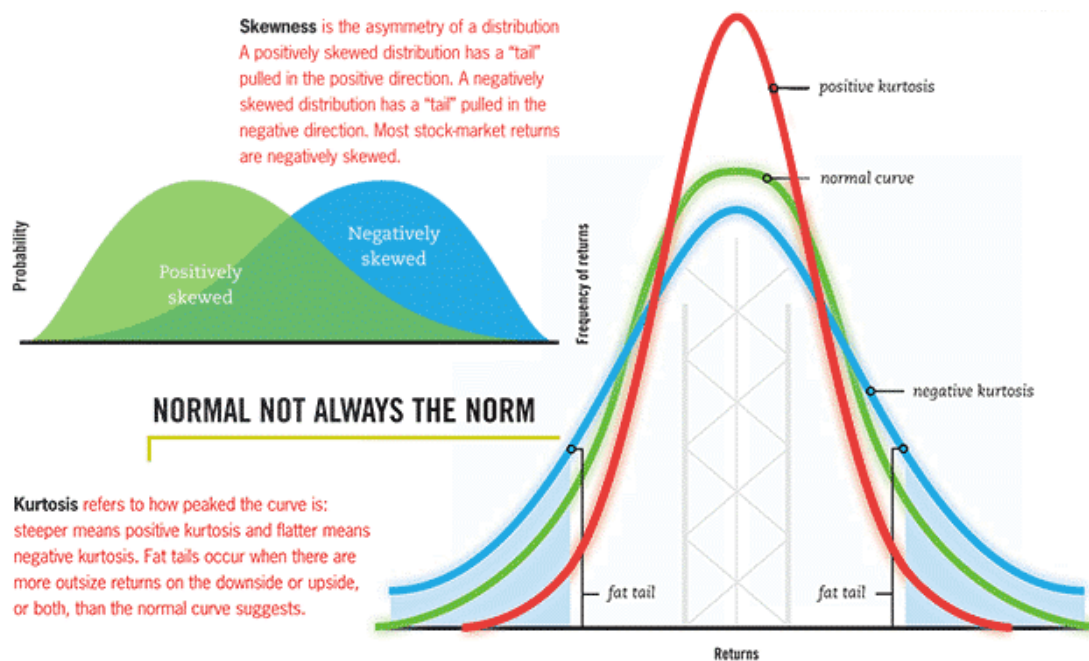


Figure 14.4-3: Probability Distributions

Although a normal distribution can be helpful, we need to carefully evaluate the shape and understand the risk inherent in the tails of potential events to determine what conditions have a material impact to the Agency.



Normal Distribution

A normal distribution is a type of continuous probability distribution for a real-valued random variable. The general form of its probability density function is:

$$f(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}$$

The parameter μ (mu) is the mean or expectation of the distribution (and also its median and mode), while the parameter σ (sigma) is its standard deviation. The variance of the distribution is σ^2 . A normal distribution is sometimes informally called a bell curve.

- In its LHS, KYMEA draws from a normal distribution for input drivers such as monthly peaks and energies.

Log-Normal Distribution

A log-normal distribution is a continuous probability distribution of a random variable whose logarithm is normally distributed. Thus, if the random variable X is log-normally distributed, then $Y = \ln(X)$ has a normal distribution. Equivalently, if Y has a normal distribution, then the exponential function of Y , $X = \exp(Y)$, has a log-normal distribution. A random variable which is log-normally distributed takes only positive real values.

- In its LHS, KYMEA draws from a log-normal distribution for input drivers such as natural gas prices.

Uniform Distribution

A uniform distribution is a symmetric probability distribution. The distribution draws from an arbitrary outcome that lies between certain bounds. The bounds are defined by the parameters, which are the minimum and maximum values.

- In its LHS, KYMEA draws from a uniform distribution for input drivers such as annual hourly load shapes and solar patterns. A single draw is made each year which produces an hourly pattern for the entire year.

Skewness

Skewness is a measure of the asymmetry of the probability distribution of a real-valued random variable about its mean. The skewness value can be positive, zero, negative, or undefined. For a unimodal distribution, negative skew commonly indicates that the tail is on the left side of the distribution, and positive skew indicates that the tail is on the right.

- In its LHS, KYMEA applies skewness to the normal and log-normal distribution to capture their distribution shape.



Kurtosis

Kurtosis is a measure of the "tails" of the probability distribution of a real-valued random variable. Like skewness, kurtosis describes the shape of a probability distribution. Positive kurtosis skews the distribution up (skinnier tails), while negative kurtosis skews the distribution down (fatter tails).

- In its LHS, KYMEA applies kurtosis to the normal and log-normal distribution to capture their distribution shape.

Random Walk

A random walk is a stochastic or random process that describes a path that consists of a succession of random steps on some mathematical space. The random-walk process does not return to the mean.

- In its LHS, KYMEA applies a random walk to variables such as long-term electricity demand and long-term natural gas prices.

Mean-Reverting Random Walk

A mean-reverting random walk differs from a simple random walk in that a restoring force pulls subsequent values back towards the mean. The strength of the restoring force is given in terms of the time to return to the mean.

- In its LHS, KYMEA applies a mean-reverting random walk to variables such as mid-term natural gas price, which fluctuates based on supply, demand, weather, and natural gas storage, but the market corrects and reverts to the mean over a period of time.

Stationary Process

Unlike a random walk, a stationary process is not tied to a continuous time series. While the random walk uses the previous point as a starting point for the next movement, in the stationary process, each draw is independent from the previous point.

- In its LHS, KYMEA applies a stationary process to variables such as monthly peak demand and monthly energy, which are not dependent on the previous month's stochastic outcome.

Stochastic Jump

A jump process is a type of stochastic process that has discrete movements, called jumps, with random arrival times, rather than continuous movement. A hybrid model, known as jump diffusion, states that the prices have large jumps interspersed with small continuous movements.

- In its LHS, KYMEA applies jump diffusion to daily natural gas and hourly energy markets to capture the discrete jumps that occur in those commodities. The jumps are highly correlated with high demand driven by extreme weather events.



Correlation and Dependence

In statistics, correlation or dependence is any statistical relationship, whether causal or not, between two or more random variables. In LHS, correlations are used to model a predictive relationship between variables.

- In its LHS, KYMEA creates a correlation matrix, so the random draws exhibit the proper relationship of correlation and dependence.



14.5 EIA Annual Energy Outlook 2020

KYMEA built its long-term stochastic draws based on the underlying projections of the EIA AEO2020. The EIA uses an econometric model to project the key input drivers of energy markets.

EIA Annual Energy Outlook 2020

The EIA projects variables, such as long-term electric demand, which is driven by macroeconomic growth, using an econometric model. The econometric model represents the economic processes of a set of variables and a set of logical and/or quantitative relationships between them. The econometric model may have various exogenous variables, and those variables may change to create various responses.

NEMS Econometric Model

The projections in the AEO2020 are generated using the National Energy Modeling System (NEMS), developed and maintained by the Office of Energy Analysis of the EIA. The projections in NEMS are developed with the use of a market-based approach, subject to regulations and standards. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources; and include regional differences in energy markets, the component modules of NEMS function at the regional level: the 9 Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation (NERC) for electricity; and 8 refining regions that are a subset of the 5 Petroleum Administration for Defense Districts (PADDs).

The NEMS econometric model is organized and implemented as a modular system shown in Figure 14.5-1.

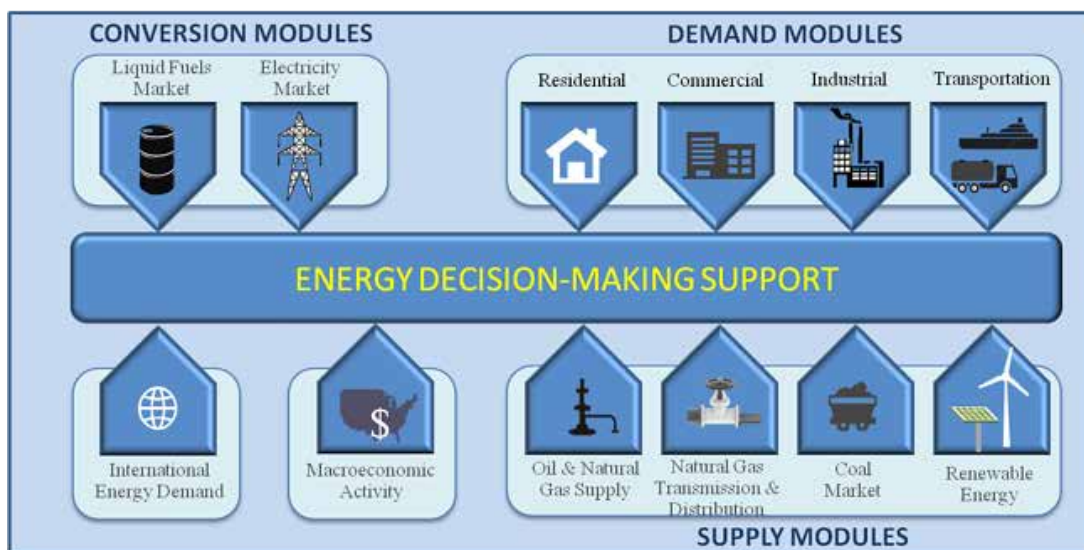


Figure 14.5-1: EIA National Energy Modeling System (NEMS)¹¹⁵

115 EIA. (n.d.). National Energy Modeling System Diagram (NEMS) [Digital image]. Retrieved April 30, 2021, from <https://www.onlocationinc.com/hs-fs/hubfs/NEMS%20Modules%20-%20updated%20graphic.png?width=652&height=330&name=NEMS%20Modules%20-%20updated%20graphic.png>



The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and a level of detail most appropriate for each energy sector. NEMS executes each of the component modules to solve for prices of energy delivered to end-users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end-users.

The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors for each year. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence. Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related CO₂ emissions, as well as emissions of SO₂, NO_x, and mercury from the electricity generation sector.

Long-Term Uncertainty – Electricity Demand Growth

To project long-term electric demand uncertainty, KYMEA interpolated the trends from the AEO2020 Macroeconomic Growth Cases into 50 long-term stochastic draws.

AEO2020 Macroeconomic Growth Cases

The AEO2020 developed Low Economic Growth and High Economic Growth cases to reflect the uncertainty in projections of economic growth. The AEO2020 report states that, “These cases show the effects of alternative growth assumptions that are higher than and lower than the Reference case energy market projections. In the economic growth cases, population and nonfarm labor productivity growth assumptions are altered, yielding changes in the growth of nonfarm employment, real disposable income, and real GDP, among other macroeconomic effects. Table 14.5-1 shows average annual growth rates of the model parameters in the AEO2020 Reference case and in the macroeconomic side cases.”

Table 14.5-1: AEO2020 Economic Growth Cases

Compound Annual Growth Rate, 2019-2050	Low Economic Growth Case	Reference Case	High Economic Growth Case
Population	0.4%	0.5%	0.7%
Nonfarm Labor Productivity	1.2%	1.5%	1.9%
Nonfarm Employment (Labor Force)	0.3%	0.5%	0.8%
Real Disposable Income Per Capita	1.4%	1.6%	1.8%
Real Gross Domestic Product	1.4%	1.9%	2.4%



Long-Term Demand - Latin Hypercube Sampling

KYMEA produced fifty (50) stochastic draws, which are bounded by the AEO growth cases. The Latin hypercube draws were made using a normal distribution with a random walk. The draws produce a time series set of multipliers that are applied to scale the hourly electricity demand up or down, reflecting macroeconomic growth on KYMEA's long-term electricity demand. Figure 14.5-2 illustrates the projections. These draws are not to be confused with weather-related uncertainty on monthly peaks and energies, which will be discussed later in this section of the report. By 2042, the lower range of the draws is 5.3% lower than the base case, while the upper range is 4.8% higher than the base case.

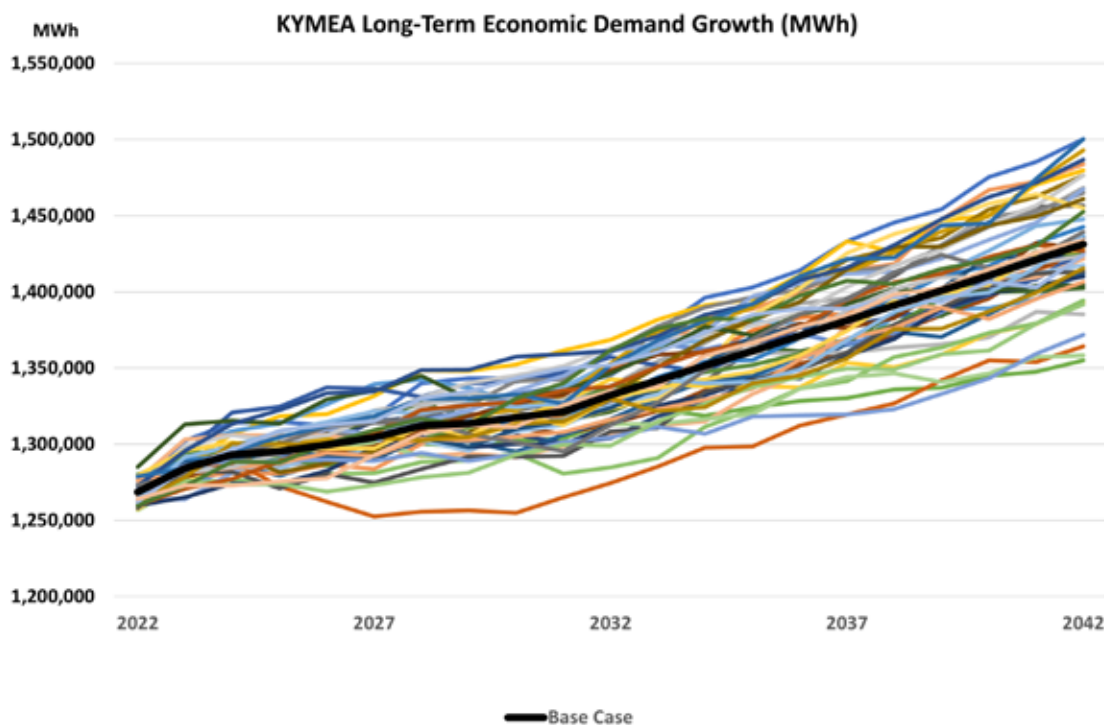


Figure 14.5-2: Long-Term Economic Demand Growth - 50 Draws (MWh)

Long-Term Uncertainty – Natural Gas Price

To project long-term natural gas price uncertainty, KYMEA interpolated the trends from the AEO2020 Oil and Gas Supply Cases into 50 long-term stochastic draws.

AEO2020 Oil and Gas Supply Cases

The AEO2020 Report states that, “estimates of technically recoverable tight/shale oil and natural gas resources are particularly uncertain and change over time as new information is gained through drilling, production, and technology experimentation. During the past decade, as more tight/shale oil formations have gone into production, estimates of technically recoverable tight/shale oil and natural gas resources have generally increased. However, these increases in technically recoverable resources (TRR) are based on many assumptions that might not apply over the long-term or over the entire tight/shale formation. For example, some resource estimates may assume that crude oil and natural gas production rates achieved in one portion of the formation represent the entire formation, even though neighboring well production rates can vary greatly. In addition, the tight/shale formation can differ significantly across the petroleum basin with respect to depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and wa-



ter content. Technological improvements and innovations may also result in the development of crude oil and natural gas resources that have not been identified yet, and therefore they are not included in the Reference case.”

“The sensitivity of the AEO projections to changes in assumptions regarding domestic crude oil and natural gas resources and technological progress is examined in two side cases. These side cases are included to provide a framework to examine the effects of higher and lower domestic supply on energy demand, imports, and prices. Assumptions associated with these cases are described below.”

“In the Low Oil and Gas Supply case, the estimated ultimate recovery per well is assumed to be 50% lower than in the Reference case for:”

- Tight oil
- Tight gas
- Shale gas in the United States
- Undiscovered resources in Alaska
- Offshore Lower 48 states

“Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% lower than in the Reference case. These assumptions increase the per-unit cost of crude oil and natural gas development in the United States.”

“In the High Oil and Gas Supply case, the estimated ultimate recovery per well is assumed to be 50% higher than in the Reference case for:”

- Tight oil
- Tight gas
- Shale gas in the United States
- Undiscovered resources in Alaska
- Offshore Lower 48 states

“Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% higher than in the Reference case. In addition, tight oil and shale gas resources are added to reflect new prospects or the expansion of known prospects. Crude oil pipeline and export capacity in the Liquid Fuels Markets Module (LFMM) is assumed to increase in the projection period to accommodate higher levels of domestic oil production.”



Long-Term Natural Gas Price - Latin Hypercube Sampling

KYMEA produced fifty (50) stochastic draws, which are bounded by the AEO oil and gas supply cases. The Latin hypercube draws were made using a log-normal distribution with a random walk. The draws produce a time series set of multipliers that are applied to scale the monthly Henry Hub natural gas price up or down, reflecting the effect of long-term natural gas prices. Figure 14.5-3 illustrates the annual projections. The long-term supply case draws are not to be confused with monthly and daily natural gas price uncertainty, which will be discussed later in this section of the report. By 2042, the lower range of the draws is 33.4% lower than the base case, while the upper range is 52.3% higher than the base case.

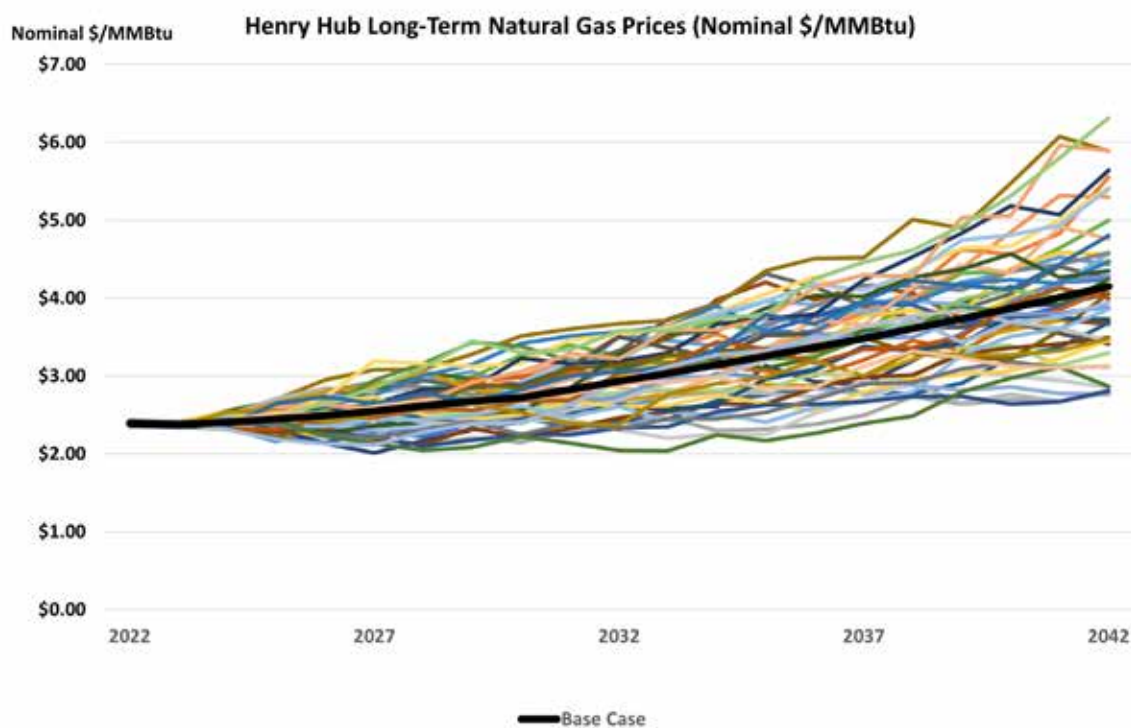


Figure 14.5-3: Long-Term Natural Gas Uncertainty - 50 Draws (nominal \$/MMBtu)



14.6 Mid-Term Uncertainties

Unlike the long-term stochastic draws which are derived from an econometric model, the mid-term stochastic draws are based on historical volatilities, standard deviations, and distributions.

Monthly Uncertainty – Natural Gas Price

Natural Gas Historic Volatility

As shown in Figure 14.6-1, mid-term natural gas price exhibits a mean-reverting random walk behavior. Explained further, over some definable period, the price of natural gas tends to move back toward the long-run mean value.

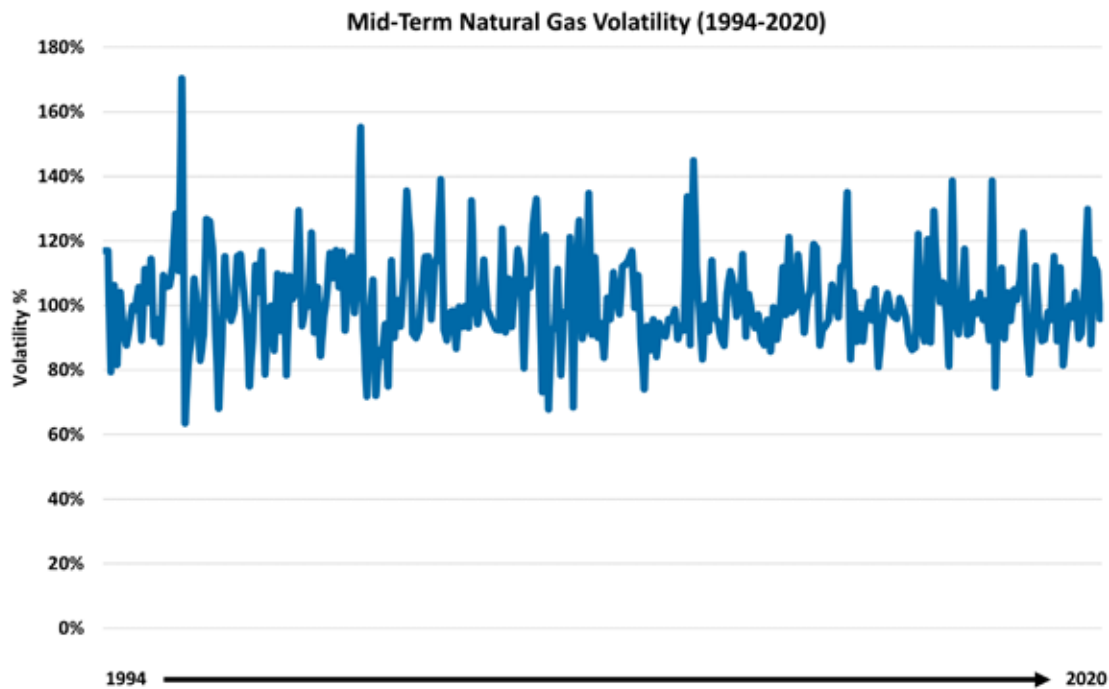


Figure 14.6-1: Mid-Term Natural Gas Volatility (1994-2020)



Natural Gas Monthly Volatility

To capture monthly natural gas price uncertainty, KYMEA combines monthly volatility with a mean reversion time. Natural gas volatility is month specific as the volatility is greater during the winter heating season and less during the summer season, as illustrated by the monthly volatility shown in Figure 14.6-2.

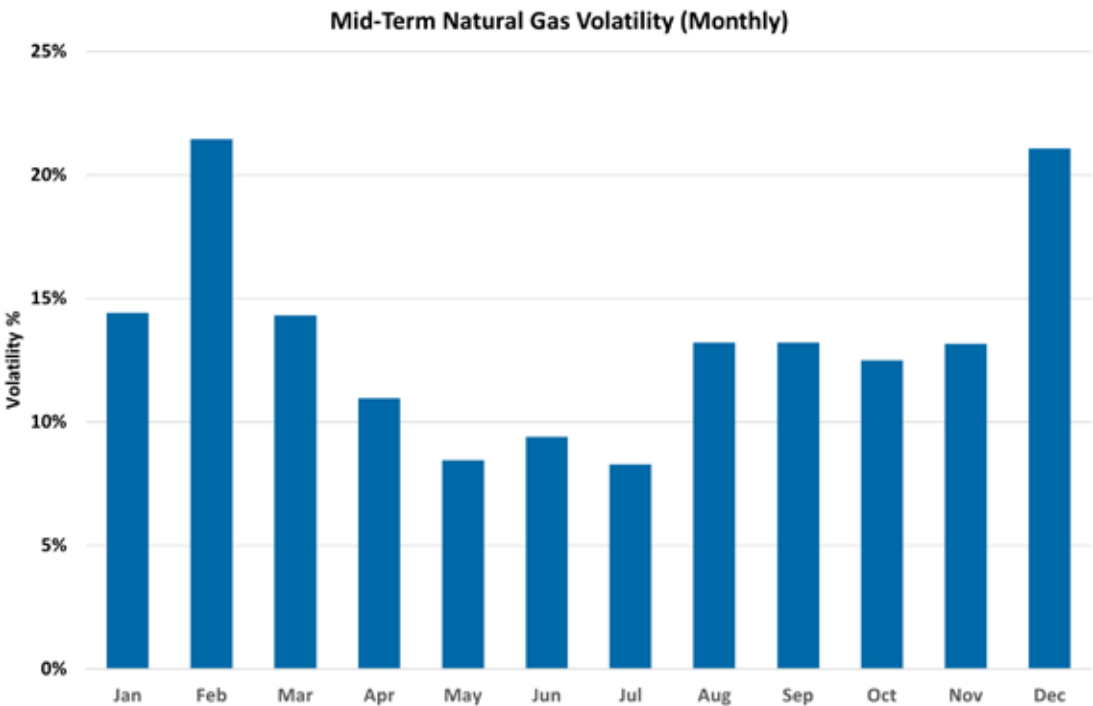


Figure 14.6-2: Mid-Term Natural Gas Volatility (Monthly)



The distribution of monthly natural gas price follows a log-normal distribution. Illustrated in Figure 14.6-3, the distribution is asymmetric, positively-skewed, and as a log-normal distribution assumes that monthly natural gas prices cannot be negative.

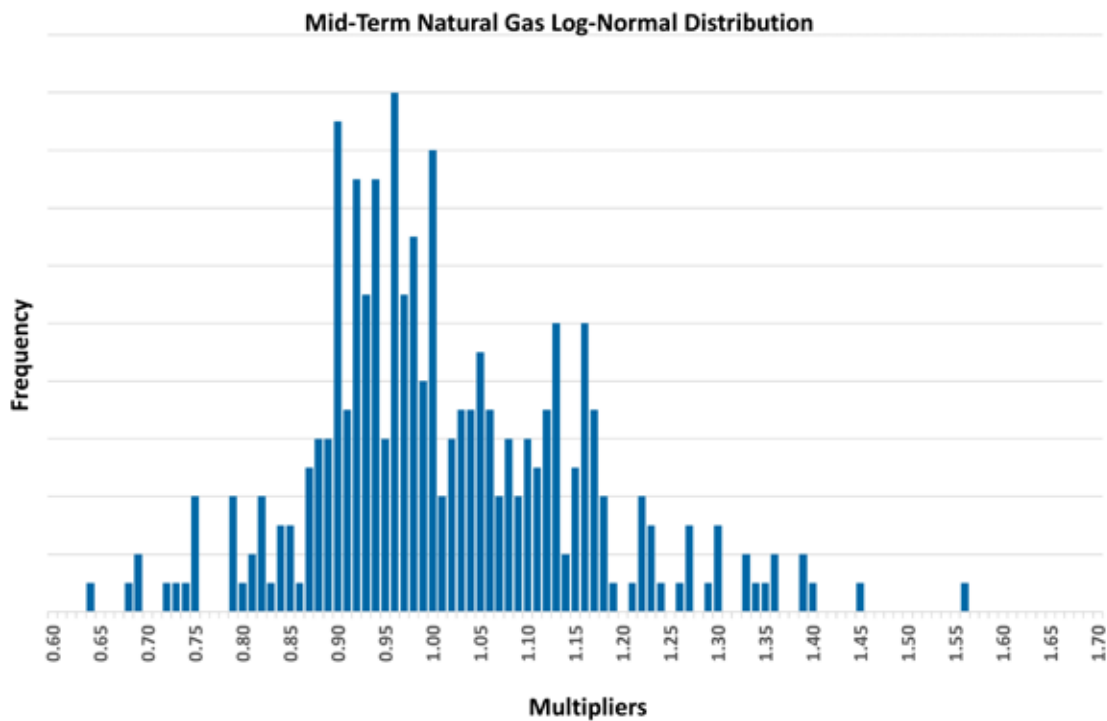


Figure 14.6-3: Mid-Term Natural Gas Log-Normal Distribution



Monthly Uncertainty – Peak and Energy

Monthly peak and monthly energy are stationary variables (i.e., stationary variables are not dependent on the previous month's random draw) with normal, positively-skewed probability distributions. For stationary variables, monthly variability is expressed in terms of the normalized standard deviation (Std Dev/Mean) for the month. To derive the values for monthly peaks and energies, KYMEA calculated the monthly growth-adjusted historical peaks and energies from 2010 – 2019. The correlation between the monthly peak and energy values is incorporated into the uncertainty analysis.

Monthly Peak Volatility

As shown in Figure 14.6-4, monthly peak volatility exhibits a normal, positively-skewed (mean > median) distribution.

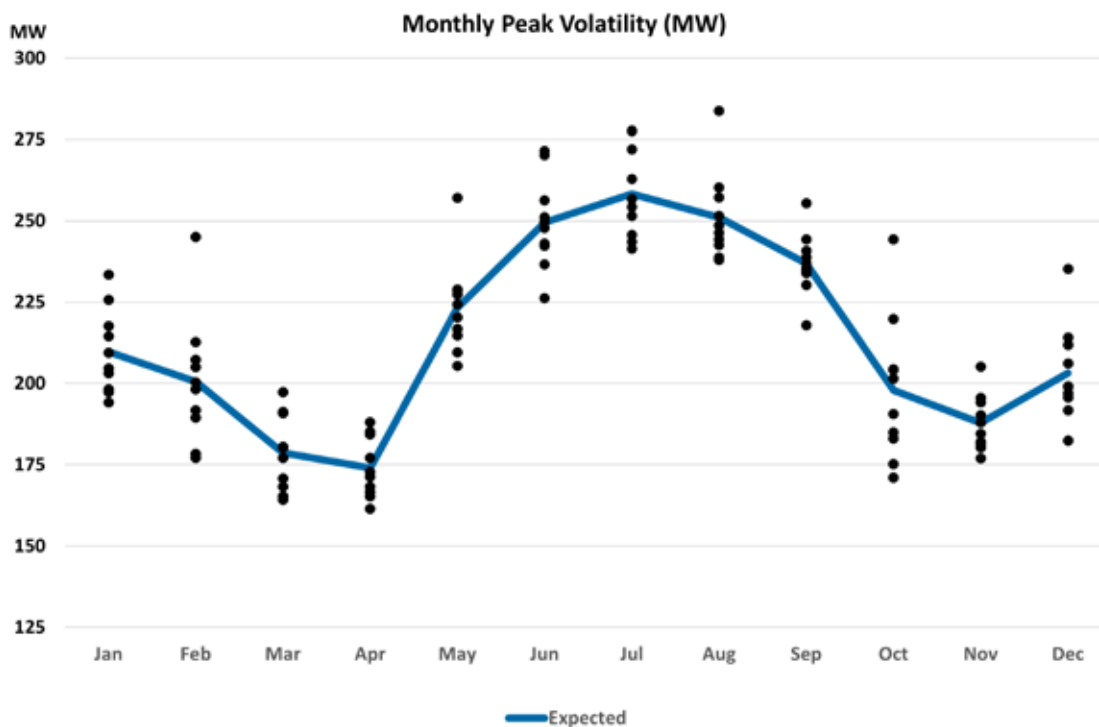


Figure 14.6-4: Monthly Peak Volatility (2010-2019)



Monthly Energy Volatility

As shown in Figure 14.6-5, monthly energy volatility exhibits a normal, positively-skewed (mean > median) distribution.

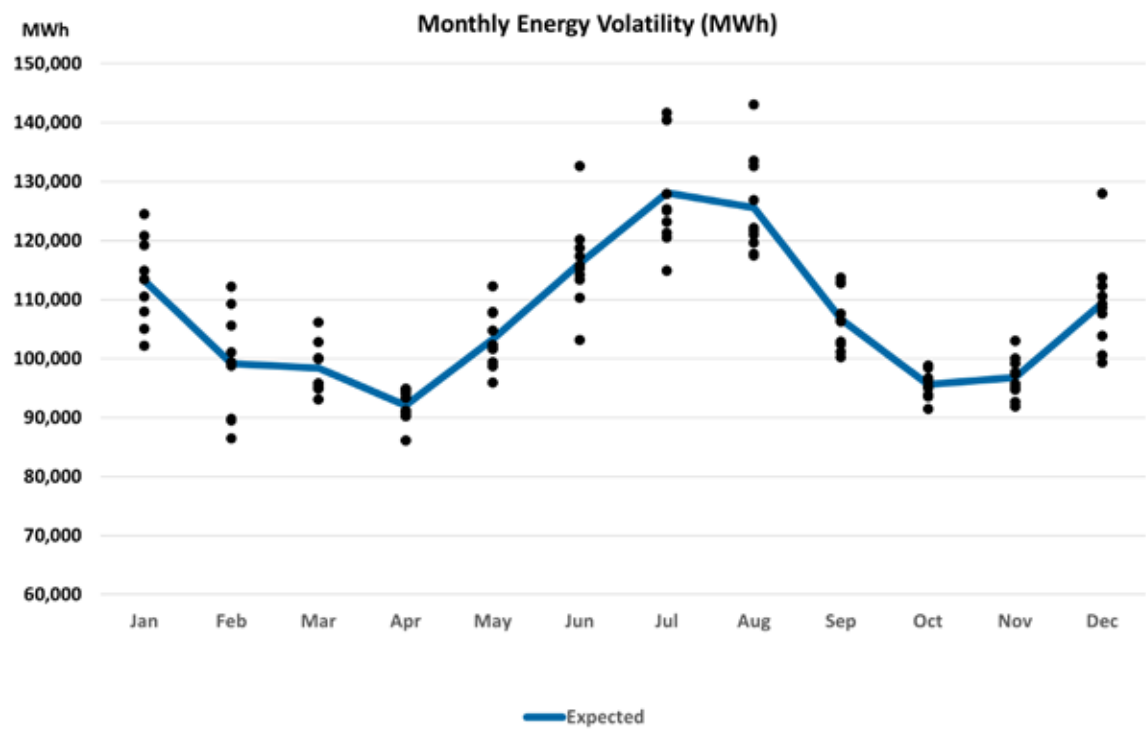


Figure 14.6-5: Monthly Energy Volatility (2010-2019)



Monthly Peak, Energy, and Correlation Values

Table 14.6-1 shows typical monthly normalized standard deviations for monthly peak and energy uncertainty variables. The monthly correlation coefficients between the peak and energy are also calculated. The monthly peak and energy correlation illustrates that in the shoulder months, the correlation is low and can be negative, while in the winter and summer seasons, the correlation is much stronger.

Table 14.6-1: Peak and Energy Standard Deviations

	Peak Standard Deviation	Energy Standard Deviation	Peak-Energy Correlation
Jan	0.0616	0.0623	0.7212
Feb	0.0976	0.0864	0.8724
Mar	0.0653	0.0417	0.3638
Apr	0.0531	0.0308	0.6053
May	0.0642	0.0480	0.4280
Jun	0.0562	0.0649	0.8495
Jul	0.0529	0.0741	0.8717
Aug	0.0542	0.0667	0.9310
Sep	0.0407	0.0476	0.2171
Oct	0.1117	0.0236	-0.3430
Nov	0.0458	0.0354	0.6223
Dec	0.0719	0.0740	0.9067



14.7 Intra-Month (Daily/Hourly) Uncertainties

A key uncertainty of electricity markets is hourly volatility. To ensure the volatility drivers are properly considered, KYMEA draws from a library of correlated historical daily natural gas volatility, hourly load patterns, solar irradiance, energy price congestion, and energy price nodal basis spreads.

Reference Hourly Shapes

The hourly reference shapes are drawn using a uniform distribution from the LHS model from the years 2010 to 2019.

- Load Patterns: Hourly shapes are available for each KYMEA member.
- Natural Gas Volatility: Daily volatility for Henry Hub and other NG Market Centers
- Solar Patterns: Hourly shapes are created using the PV Watts Calculator and solar irradiance patterns.
- Nodal Basis Spreads: Hourly basis spreads are available for the five nodal equivalence points of interest described earlier in Section 11.

For each year of a given stochastic future (draw 1, draw 2, etc.), a correlated shape for each of the four variables is drawn from the years 2010-2019 using a uniform distribution. By randomizing the shape for each draw, consideration is given to the various weather patterns and temperatures that exist across the geographic regions of the market model.

Load Hourly Volatility

Figure 14.7-1 illustrates KYMEA's load shapes for the years 2010-2019 shown as a duration curve.

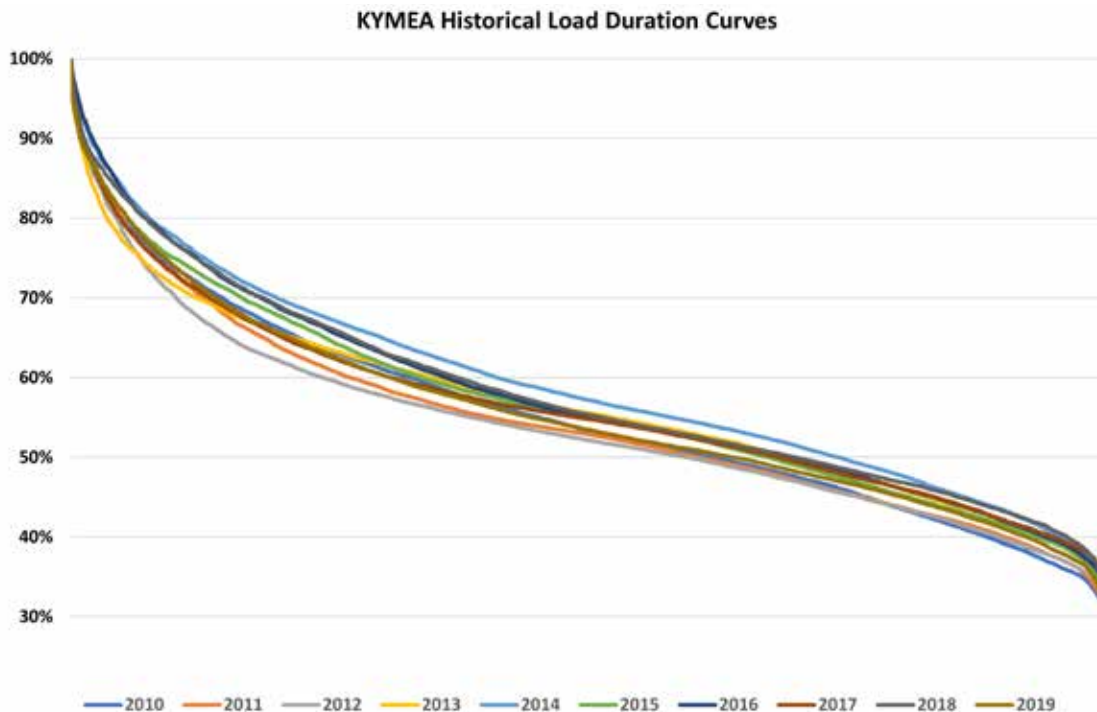


Figure 14.7-1: Historical Load Duration Curves



Natural Gas Daily Volatility

To address daily spot market natural gas volatility, KYMEA analyzed the daily volatility from 2010 to 2019. This period was chosen as it corresponds to KYMEA's library of load shapes as well as the beginning of the shale natural gas and fracking boom.

The expected range of daily volatility by month is shown in Figure 14.7-2.

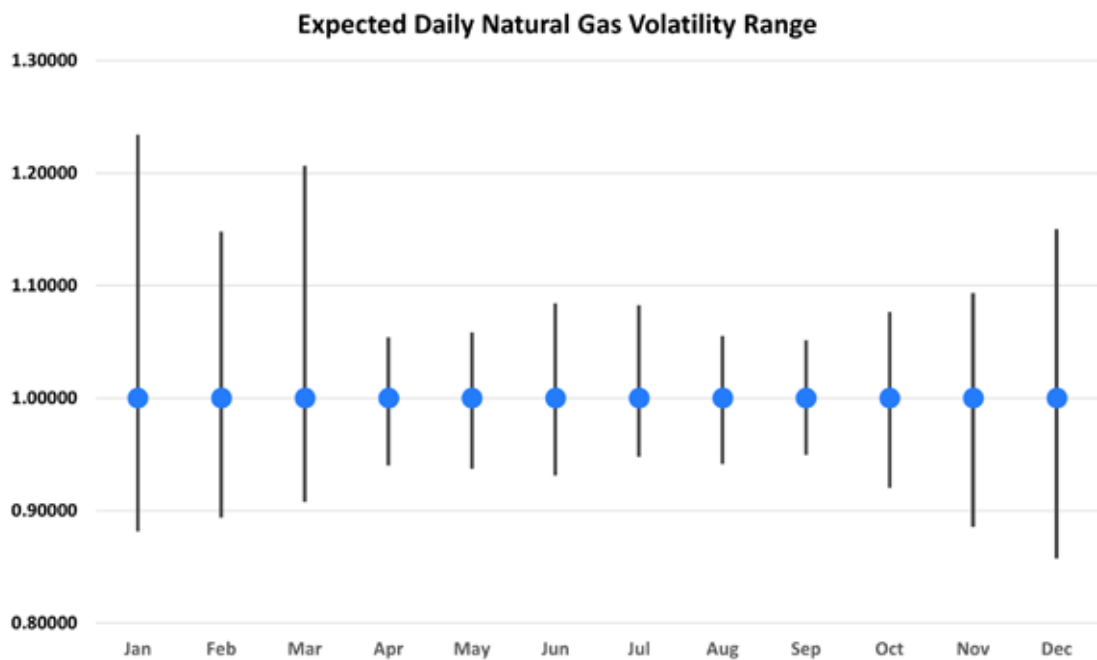


Figure 14.7-2: Expected Daily Natural Gas Volatility

Additionally, low and high daily volatility ranges are shown in Figure 14.7-3.

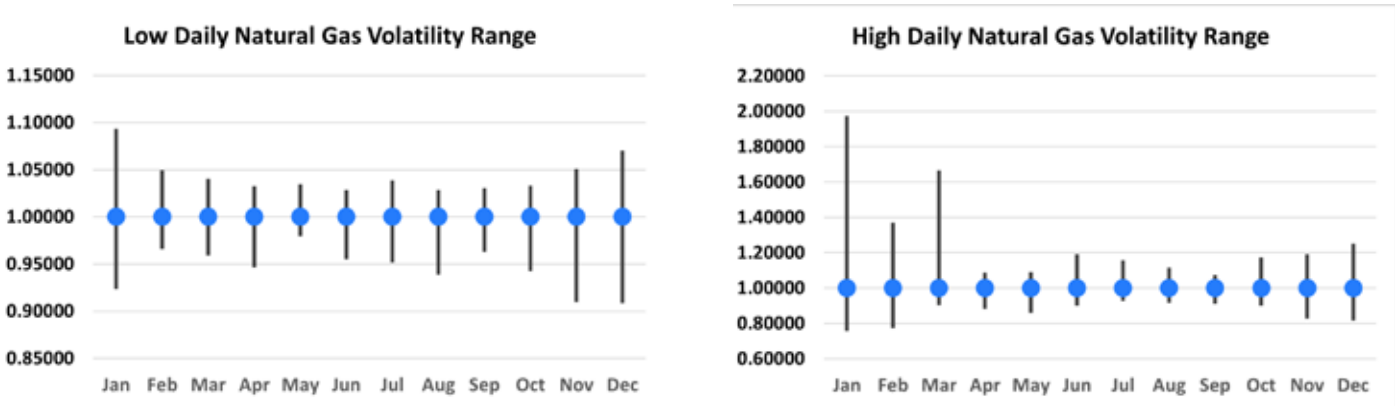


Figure 14.7-3: Low and High Daily Natural Gas Volatility



14.8 Stochastic Hourly Price Trajectories

Introduction

As described earlier in Section 11, KYMEA uses the EnCompass co-optimization market model to project energy, ancillary service, and capacity prices. As illustrated by Figure 14.8-1, the stochastic prices created represent 50 stochastic futures tied to the Latin hypercube draws.

The coupling of Encompass model simulations, Latin Hypercube draws, cross commodity and market driver correlations, stochastic jumps, and zonal to nodal price formation is an elaborate process. The previously described uniform draws taken from the historic years of 2010-2019 provides the underlying covariance between modal markets, loads, natural gas market centers, and solar irradiance. Encompass model simulations are made for North America in its entirety for key market drivers (e.g., natural gas uncertainty), and the resulting drivers and prices are interpolated to match the conditions of the uniform annual draw.

As illustrated by Figure 14.8-1, the long-term market prices are less volatile in the early years due to lower long-term natural gas and economic growth volatility, as described earlier in this section of the report. As the long-term natural gas and economic uncertainty grow over time, the market prices become more volatile and uncertain.

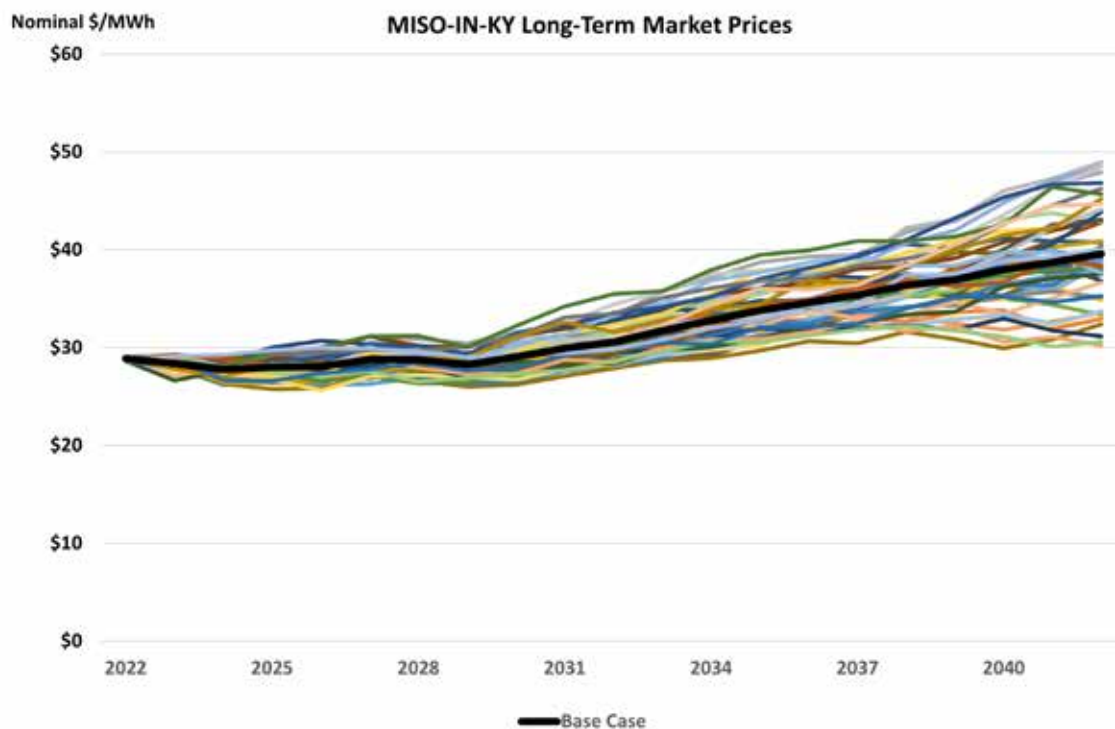


Figure 14.8-1: MISO-IN-KY Long-Term Market Prices - 50 Draws (nominal \$/MWh)

Using this technique, KYMEA is able to create a properly correlated and exhaustive set of hourly stochastic input drivers that is forward looking to match the dynamic changes which occur in the market under a variety of underlying market conditions.



14.9 Risk Analysis Metrics

KYMEA frequently updates the EnCompass stochastic simulations to assess and manage risk as the underlying market conditions and other input drivers change over time. To analyze and measure risk, KYMEA utilizes risk profiles and tornado charts.

Risk Profiles Explained

Risk profiles provide valuable insight into the riskiness of a portfolio. The x-axis (levelized average production cost) shows the outcome of each stochastic draw. The y-axis is the cumulative probability of occurrence of each outcome between 0% and 100%. For example, if the far-left point is 5.06¢/kWh and the far-right point is 5.66¢/kWh, then there is 100% confidence that the cost will be between those two points as illustrated in Figure 14.9-1. The narrower the range, the less risk.

The 50 blue dots of the unhedged portfolio creates an s-shaped curve or sigmoid curve. By the design of the Latin Hypercube draws, each outcome has an equal probability of occurrence (2%).

To manage risk, KYMEA looks for ways to minimize the “fat tails” of a risk profile, often trading opportunity for risk. A risk-averse profile would be a vertical line, but achieving a risk-free vertical line likely moves the entire profile far to the right. Think of it as buying far more insurance than is necessary and laying off the risk on the insurance company. KYMEA recognizes there is inherent risk in the electric utility business, drawing a balance between risk and reward using tools such as a risk profile.

A prudently hedged portfolio, as illustrated by the black dotted line in Figure 14.9-1, narrows the risk profile by clipping the fat tails without shifting the entire profile too far to the right.

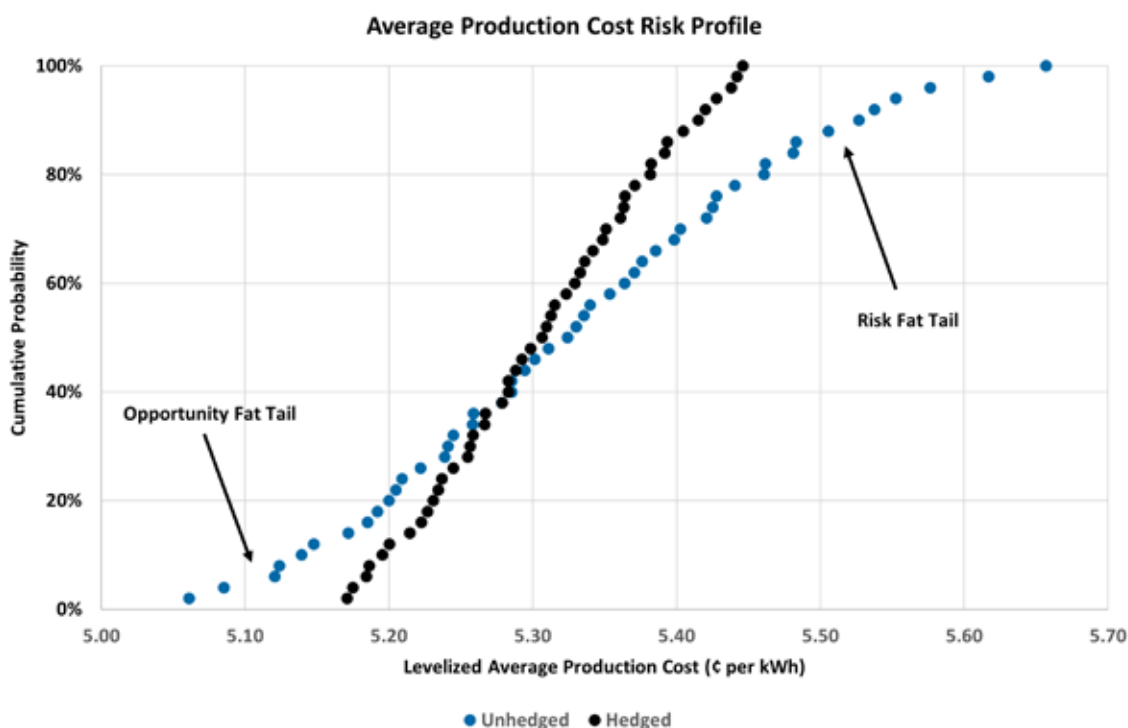


Figure 14.9-1: Average Production Cost Risk Profile



Tornado Charts Explained

Tornado charts depict the sensitivity of the levelized average production cost (APC) to changes in the various fundamental drivers. As shown in Figure 14.9-2, APC (black bar) is the dependent variable, and the remaining nine (9) drivers are independent variables (gray bars).

The length of the black bar is the uncertainty range of APC for a selected time frame. The far-left point is 5.06¢/kWh, and the far-right point is 5.66¢/kWh. The lengths of the gray bars illustrate each independent variable's impact on APC; the longer the bar, the greater the impact. The expected value is signified by the vertical line. When a gray bar is offset to the left that means that independent variable puts downward pressure on APC (good outcome). Conversely, if the gray bar is offset to the right, then the independent variable puts upward pressure on APC (bad outcome).

Tornado Charts provide helpful understanding of the various drivers of risk and how the risk of each driver can be mitigated through hedging.

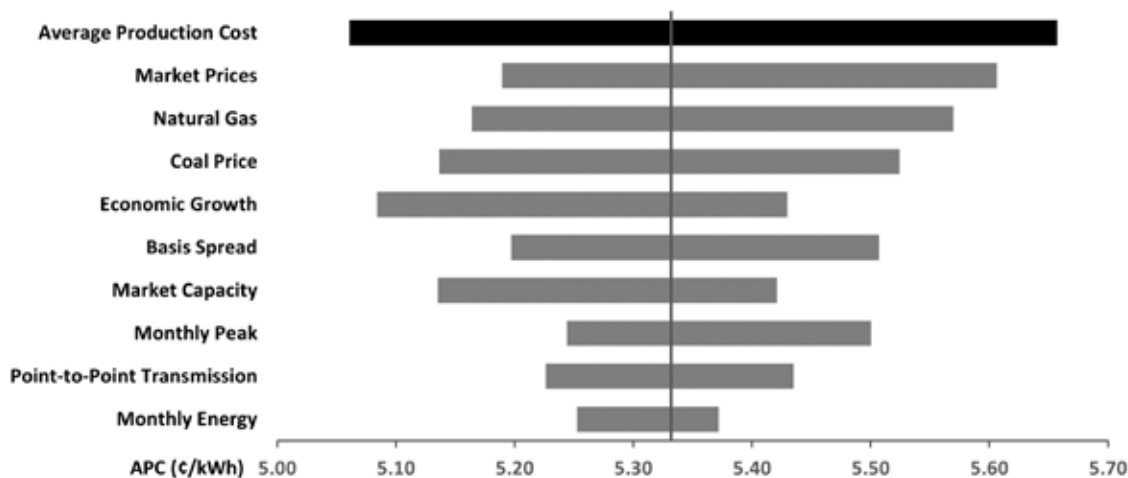


Figure 14.9-2: Tornado Chart Example

Hedging

KYMEA creates a position report which calculates the Agency's portfolio exposure. Spot market price, fuel price, load, unit availability are all considerations when calculating the portfolio exposure. KYMEA's PPAs provide a hedge to a certain amount of market exposure, and the position report calculates hedge quantities based on the current forward curve.



14.10 Selected Plan Reliability - Stress Analysis

Wildcard Events

Wildcards are high-impact, low-probability events. Recent wildcard events that have caught the nation's attention are polar vortexes, which could have a serious detrimental impact on the KYMEA's competitive position and ability to reliably serve its load. While possible and likely to create dramatic change if they occur, wildcards are less probable than other key uncertainties.

Polar Vortex

The science behind polar vortex events is described in Figure 14.10-1. In the past, a polar vortex event was not necessarily high impact for the utility industry; however, as more coal and nuclear are retired and the reliance on natural gas and renewable energy increases, the impact of polar vortexes has heightened as grid resiliency declines.

Understanding the polar vortex

The Arctic polar vortex is a strong band of winds in the stratosphere, surrounding the North Pole 10–30 miles above the surface.

The polar vortex is far above and typically does not interact with the polar jet stream, the flow of winds in the troposphere 5–9 miles above the surface. But when the polar vortex is especially strong and stable, the jet stream stays farther north and has fewer "kinks." This keeps cold air contained over the Arctic and the mid-latitudes warmer than usual.

Every other year or so, the Arctic polar vortex dramatically weakens. The vortex can be pushed off the pole or split into two. Sometimes the polar jet stream mirrors this stratospheric upheaval, becoming weaker or wavy. At the surface, cold air is pushed southward to the mid-latitudes, and warm air is drawn up into the Arctic.

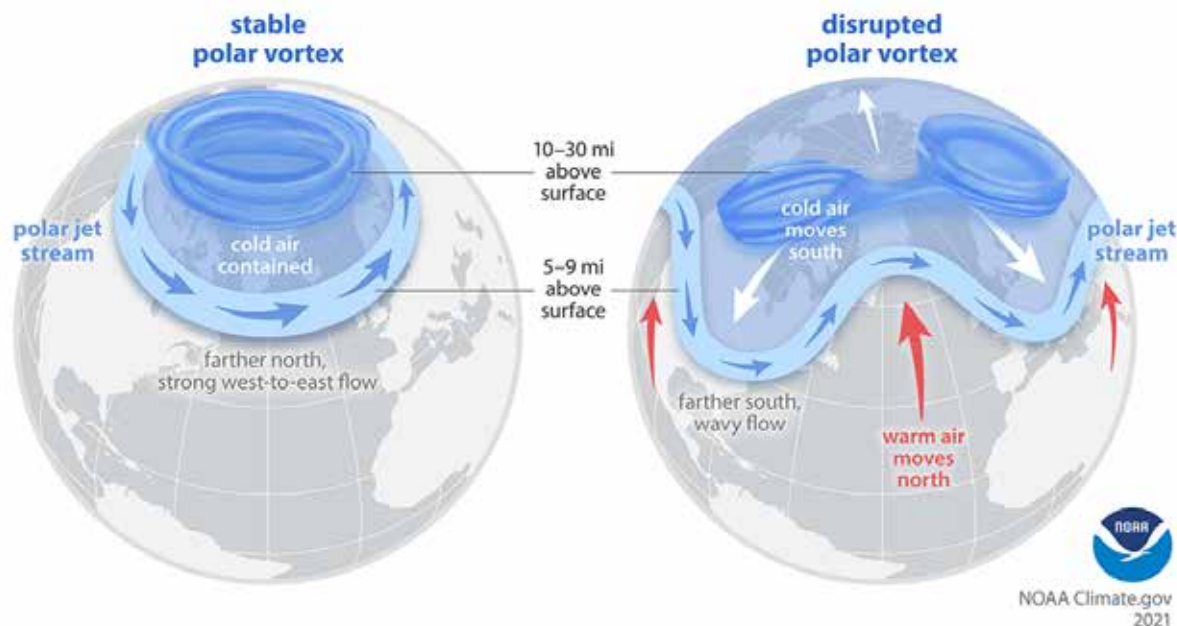


Figure 14.10-1: The Science Behind the Polar Vortex¹¹⁶

116 NOAA. (2021). Understanding the Polar Vortex [Digital image]. Retrieved April 30, 2021, from https://scijinks.gov/polar-vortex/science_behind_polar_vortex.png



Natural Gas & Electricity Market Coordination Issues

The increasing role of natural gas has raised concerns about the effect on power grid reliability when fuel is not available for generating plants. Cold weather events shed light on this concern. For example, in PJM, the January 6-8, 2014, polar vortex brought prolonged, deep cold to the entire PJM footprint and the surrounding regions. PJM set a new wintertime peak demand record of 141,846 MW the evening of January 7, 2014, while dealing with higher-than-normal generation outages. During the peak demand hour, 22% of generation capacity – including coal, gas, and nuclear – was out of service.

The generation forced outage rate was two to three times higher than what is normally expected. Equipment issues associated with both coal and natural gas units caused the greatest proportion of forced outages. Winter demand for natural gas for heating can potentially interrupt gas deliveries to generators, as was seen in the winter of 2014. Natural gas interruptions constituted approximately 25% of the total outages.

There are two main types of gas delivery services illustrated in Figure 14.10-2.

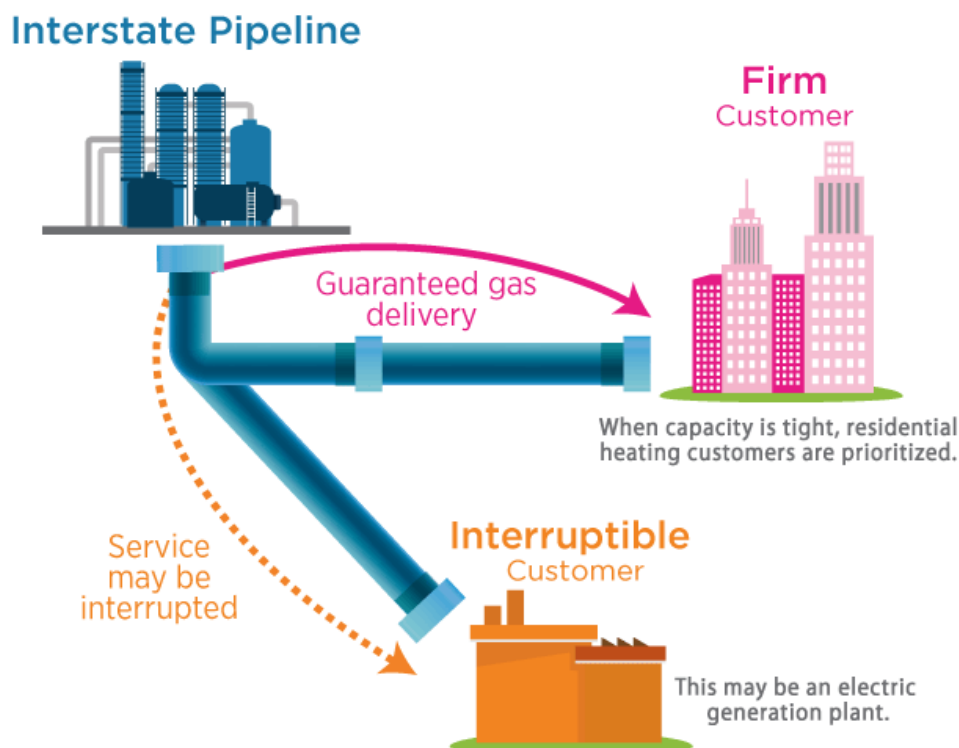


Figure 14.10-2: Two Main Types of Gas Delivery Services¹¹⁷

Firm Transportation guarantees gas delivery throughout the year that allows generators to meet power obligations on any given day. Through changes in the capacity market, generators now recover firm transportation costs in PJM markets.

Interruptible Transportation provides the most risk of non-delivery. There is no guarantee that capacity (the volume available in a gas pipeline or storage facility) will be available. When pipeline capacity is tight, such as during the extreme cold weather conditions in 2014, generators with interruptible contracts may have their service interrupted.

¹¹⁷ PJM. (n.d.). There are Two Main Types of Gas Delivery Services [Digital image]. Retrieved April 26, 2021, from <https://learn.pjm.com/three-priorities/keeping-the-lights-on/gas-electric-industry/natural-gas-electric-market.aspx>



2021 ERCOT Energy Crisis

Beginning on February 14, 2021, an extreme cold weather event caused by a polar vortex, stretched from Canada to Texas. The Texas (ERCOT) market was ill-prepared for the polar vortex event, which lasted more than one week and led to massive rolling blackouts and loss of life and property. The ERCOT maximum ORDC, which is currently set as \$9,000 per MWh, is established as the real-time energy price which reflects firm load shedding. The price signal is essential in the ERCOT energy-only market (no capacity market) because it provides efficient economic signals to increase the electric generation needed to restore the load. The prolonged extreme cold weather event triggered the maximum \$9,000 per MWh price signal, which lasted for days, causing financial distress and even bankruptcies.

The preliminary report from ERCOT to the Public Utility Commission of Texas identified the following outage cause categories.

- Existing Outages: Generator outages or derates that started before the issuance of the Operating Condition Notice on February 8, 2021; includes ongoing planned and forced outages as well as seasonally mothballed units. Some existing outages ended before or during the event, allowing the unit to return to service.
- Fuel Limitations: Generator outages or derates due to lack of fuel, contaminated fuel, fuel supply instability, low gas pressure, or less efficient alternative fuel supply.
- Weather Related: Generator outages or derates explicitly attributed to cold weather conditions in the RFI responses. This includes but is not limited to frozen equipment—including frozen sensing lines, frozen water lines, and frozen valves—ice accumulation on wind turbine blades, ice/snow cover on solar panels, exceedances of low temperature limits for wind turbines, and flooded equipment due to ice/snow melt.
- Equipment Issues: Generator outages or derates due to facility equipment failures or malfunctions not explicitly attributed to cold weather in the RFI response. This includes trips and derates related to control system failures, excessive turbine vibrations, or other equipment problems.
- Transmission Loss: Generator outage or derates due to forced outages on directly connected transmission facilities.
- Frequency Related: Generator outage or derates attributed to frequency deviations from 60Hz; includes automatic tripping due to under-frequency protection relays and any automatic or manual tripping attributed to plant control system issues related to frequency deviation.
- Miscellaneous: Other generator outages or derates not linked to one of the above causes, including outages for which a cause is yet unknown.



The outage and derate impact is illustrated in Figure 14.10-3.

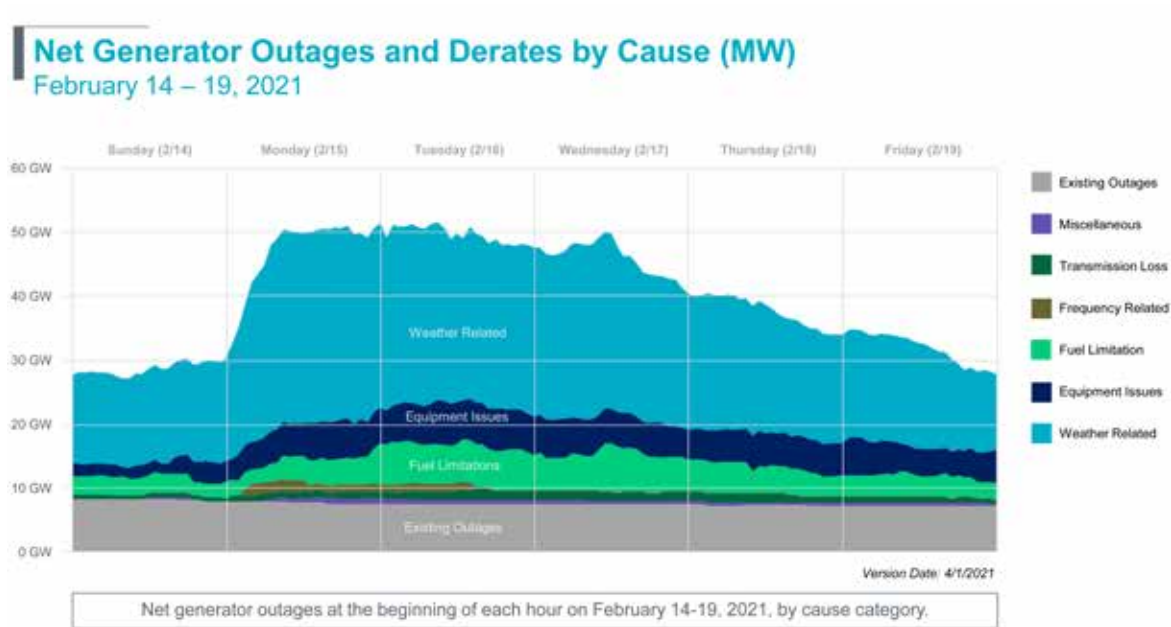
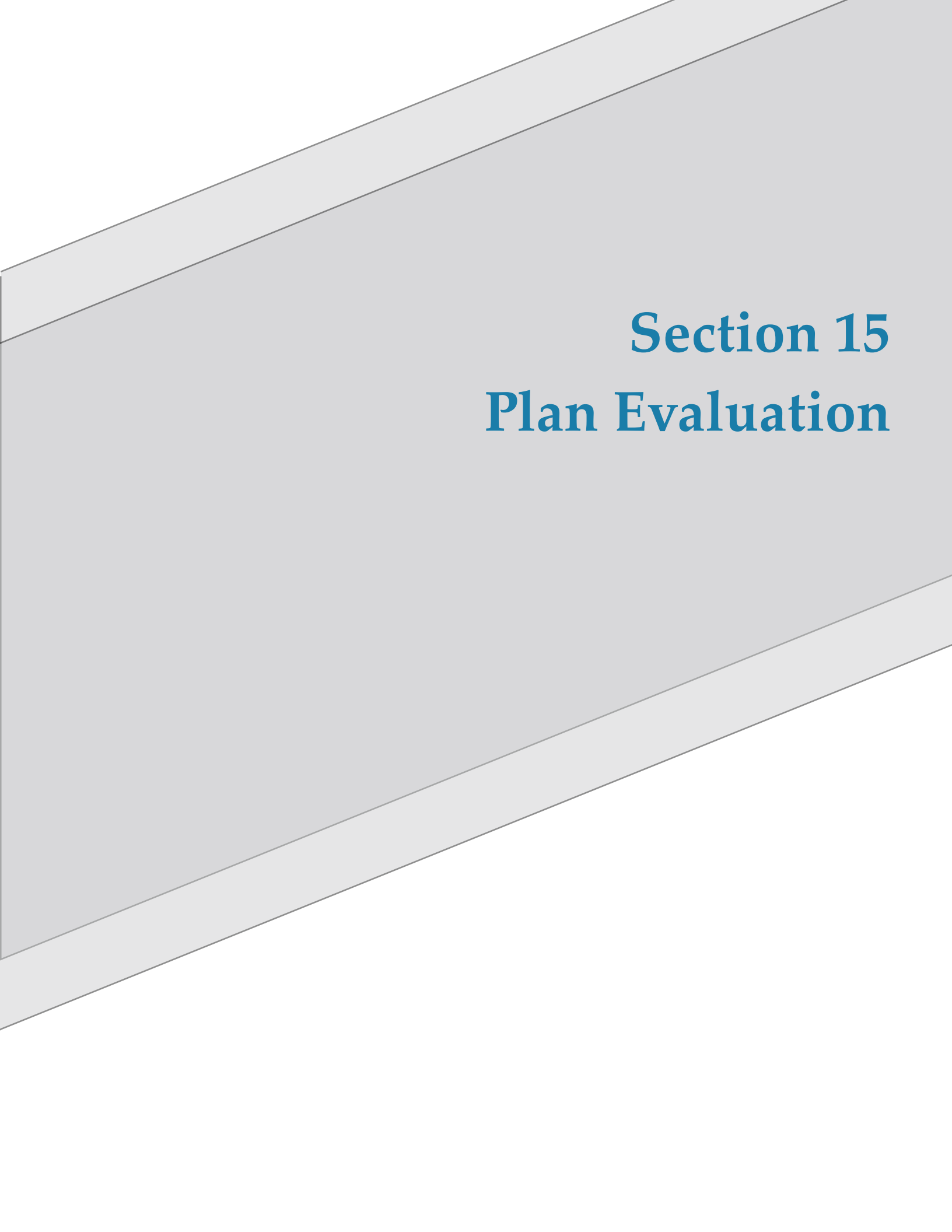


Figure 14.10-3: ERCOT 2021 Polar Vortex Generator Outages by Cause (MW)¹¹⁸

Stress Test Reliability

Before each summer and winter season, to address potential wild card events, KYMEA performs a stress test analysis to ensure the KYMEA load can be served under extreme weather conditions.

¹¹⁸ Rickerson, W. (n.d.). Preliminary Report on Causes of Generator Outages and Derates For Operating Days February 14 – 19, 2021 Extreme Cold Weather Event [Letter written April 6, 2021 to Chairman D'Andrea]. Retrieved May 26, 2021, from http://www.ercot.com/content/wcm/lists/226521/51878_ERCOT_Letter_re_Preliminary_Report_on_Outage_Causes.pdf



Section 15

Plan Evaluation

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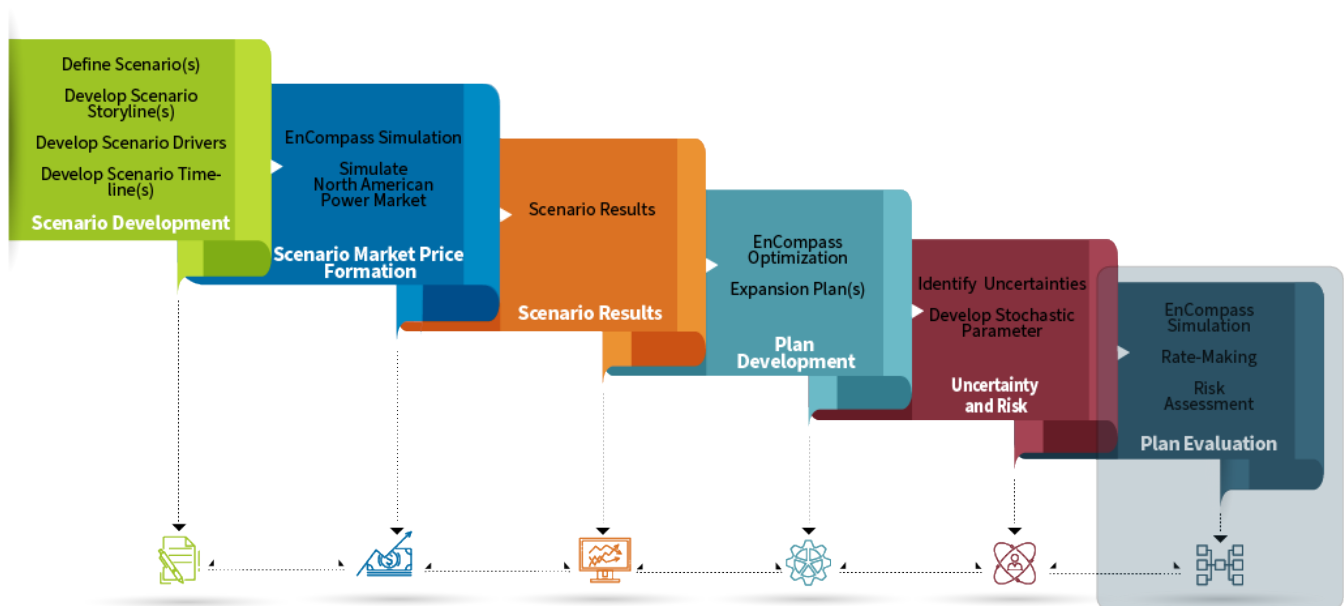


15. PLAN EVALUATION

15.1 Evaluation Approach

The final step of the IRP Flowchart is Plan Evaluation. Plan Evaluation provides a detailed analysis of the plans, or portfolios, comparing the cost, reliability, market exposure, emissions, and risks associated with each plan. The results and their risk metrics provide KYMEA with critical information regarding the cost ranking and robustness of each plan.

IRP FLOWCHART



Evaluation Period and Risk Analysis Quadrant

As described in Sections 13 and 14, Plan Development and Uncertainty and Risk, the near-term and long-term plan evaluations considered different time periods and risk analysis quadrants.

Near-Term Evaluation

The near-term evaluation focused on actionable decisions that needed to be made by the KYMEA Board of Directors at the time this IRP was being written.

- **Evaluation Period:** 5 Years
- **Risk Analysis Quadrant:** Market Sensitivities



Long-Term Evaluation

The long-term evaluation focused on possible future plans. There were no immediate actions that need to be considered for the long-term evaluation. The purpose of the evaluation was to assess how each long-term plan would perform under the nine plausible scenarios identified in Sections 10 - 12, Scenario Development, Market Price Formation, and Results.

- **Evaluation Period:** 20 Years
- **Risk Analysis Quadrant:** Scenarios



15.2 Near-Term Plan Evaluation

As discussed in Section 13, Plan Development, 11 near-term plans were developed for the KYMEA Board of Director's consideration. To fully evaluate the near-term plans, detailed modeling was created in the EnCompass planning model to identify transmission constraints and costs, resources, and market opportunities.

EnCompass Topology Definitions

EnCompass uses an industry-standard topology structure of BAs, Areas, and Regions. As an example, MISO is a BA, the Big Rivers Electric Corporation transmission area is a Local Balancing Area, or Area, inside the MISO BA, and generating assets inside the Big Rivers Electric Corporation system provide ancillary services to a specific MISO Ancillary Service Region.

KYMEA Topology

The EnCompass structure is very flexible where the definition of a BA, Area, and Region can be defined by the user to fit the user's specific portfolio. Most of KYMEA's load is not in a competitive market, but rather, resides in the LKE transmission system. To gain access to the MISO and PJM competitive markets, KYMEA must secure firm point-to-point and network transmission services. To mimic the nuances of the transmission service, which involves a point-of-receipt (POR), point-of-delivery (POD), and Locational Marginal Price (LMP) for delivery to the LKE transmission system, KYMEA leveraged the EnCompass BA and Area structure to capture the details involved with delivering power to the LKE transmission system from a variety of sources and locations, both inside and outside of the LKE system. The structure involved creating 7 "Balance Authorities" and 17 "Areas" as shown in Figure 15.2-1.

7 Balancing Authorities | 17 Areas

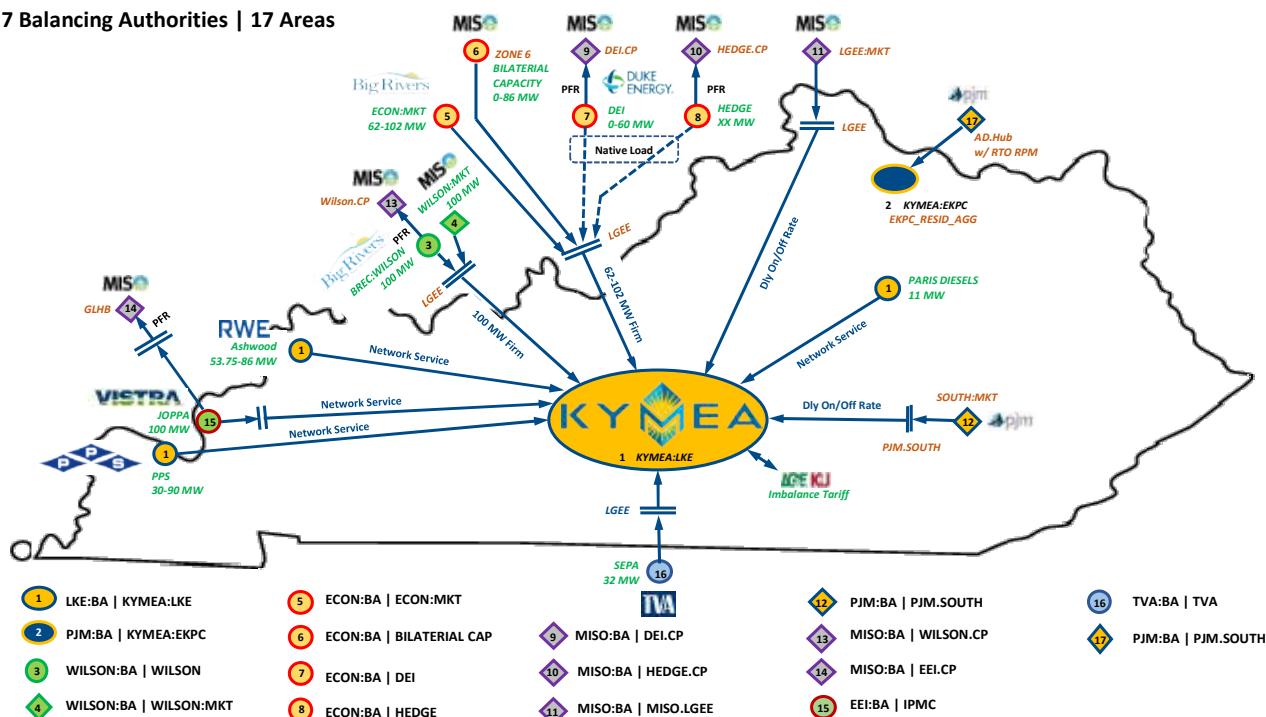


Figure 15.2-1: KYMEA BA and Area Topology Map



Near-Term Plan Results

The results of the near-term plans with the high-base-low natural gas, energy price, and capacity price sensitivities are provided in Table 15.2-1. Each plan considered two levels of MISO point-to-point transmission service to provide additional cost versus reliability analysis. The lone exception is PLAN B, which considered three levels of MISO transmission service. The table definitions are described in Section 13 (Plan Development).

Table 15.2-1: Near-Term Plan Results

	Firm Capacity and Reserve Margin					Bilateral Capacity, MISO Point-to-Point Transmission, Operating Reserves					Levelized Cost millions \$ (6/2019 - 5/2027)			Levelized Cost ¢ per kWh (6/2019 - 5/2027)		
	Planning Capacity	PPS Peaking	Ashwood Solar	DEI PPA	Reserve Margin	Bilateral Capacity	Dynamic Schedule	MISO PTP	1-in-10 Margin	Net Peak Margin	Low Market	Base Market	High Market	Low Market	Base Market	High Market
Plan A	159	30	54	0	-15.6%	79 15.2%	100 (42 min)	185 (27)	12.2%	6.2%	64.899	70.288	72.981	5.016	5.433	5.641
								202 (40)	18.3%	13.2%	66.010	71.395	74.088	5.102	5.518	5.726
								162 (0)	25.5%	21.4%	64.770	69.516	71.114	5.006	5.373	5.496
Plan B	159	90	54	0	7.8%	19 15.2%	100 (42 min)	177 (15)	26.2%	27.6%	65.460	70.199	71.785	5.059	5.426	5.548
								202 (40)	39.9%	37.9%	67.133	71.866	73.453	5.189	5.555	5.677
								177 (15)	9.4%	2.9%	66.440	69.999	70.675	5.135	5.410	5.462
Plan C	159	30	54	60	7.8%	19 15.2%	100 (42 min)	202 (40)	18.3%	13.2%	68.113	71.666	72.339	5.264	5.539	5.591
								177 (15)	14.7%	9.1%	66.245	70.069	70.948	5.120	5.416	5.484
								202 (40)	23.7%	19.3%	67.919	71.738	72.613	5.249	5.545	5.612
Plan D	159	45	54	45	7.8%	19 15.2%	100 (42 min)	177 (15)	20.1%	15.2%	66.046	70.141	71.225	5.105	5.421	5.505
								202 (40)	29.1%	25.5%	67.719	71.810	72.890	5.234	5.550	5.634
								177 (15)	20.9%	2.9%	64.508	69.395	71.598	4.986	5.364	5.534
Plan E	159	30	86	0	-9.4%	63 15.2%	100 (67 min)	202 (40)	29.9%	13.2%	66.180	71.064	73.264	5.115	5.493	5.663
								177 (15)	37.1%	21.4%	65.351	69.750	71.121	5.051	5.391	5.497
								202 (40)	46.0%	31.7%	67.024	71.419	72.788	5.180	5.520	5.626
Plan F	159	75	86	0	8.2%	18 15.2%	100 (67 min)	177 (15)	20.9%	2.9%	66.134	69.624	70.289	5.111	5.381	5.433
								202 (40)	29.9%	13.2%	67.806	71.293	71.954	5.241	5.510	5.561
								177 (15)	26.3%	9.1%	65.935	69.695	70.565	5.096	5.387	5.454
Plan G	159	30	86	45	8.2%	18 15.2%	100 (67 min)	202 (40)	35.3%	19.3%	67.608	71.364	72.230	5.225	5.516	5.583
								177 (15)	24.5%	7.0%	66.831	69.855	69.959	5.165	5.399	5.407
								202 (40)	33.5%	17.3%	68.505	71.523	71.624	5.295	5.528	5.536
Plan H	159	45	86	30	8.2%	18 15.2%	100 (67 min)	177 (15)	31.7%	15.2%	66.216	69.814	70.406	5.118	5.396	5.442
								202 (40)	40.6%	25.5%	67.890	71.483	72.073	5.247	5.525	5.570
								177 (15)	24.5%	7.0%	66.831	69.855	69.959	5.165	5.399	5.407
Plan I	159	40	86	60	18.0%	0 18.0%	100 (67 min)	202 (40)	33.5%	17.3%	68.505	71.523	71.624	5.295	5.528	5.536
								177 (15)	31.7%	15.2%	66.216	69.814	70.406	5.118	5.396	5.442
								202 (40)	40.6%	25.5%	67.890	71.483	72.073	5.247	5.525	5.570
Plan J	159	60	86	30	14.1%	3 15.2%	100 (67 min)	177 (15)	31.7%	15.2%	66.216	69.814	70.406	5.118	5.396	5.442
								202 (40)	40.6%	25.5%	67.890	71.483	72.073	5.247	5.525	5.570
								177 (15)	24.5%	7.0%	66.831	69.855	69.959	5.165	5.399	5.407
Plan K	159	60	86	30	14.1%	3 15.2%	100 (67 min)	202 (40)	40.6%	25.5%	67.890	71.483	72.073	5.247	5.525	5.570
								177 (15)	24.5%	7.0%	66.831	69.855	69.959	5.165	5.399	5.407
								202 (40)	40.6%	25.5%	67.890	71.483	72.073	5.247	5.525	5.570

Near-Term 15 MW PTP Plan Comparison

Table 15.2-2 summarizes the 15 MW MISO PTP Plans. The table provides a cost and percentage comparison against the lowest cost plan in each market category – Low, Base, High. For example, from the table above, the lowest cost plan(s) with the 15 MW MISO PTP transmission are PLAN F under low (\$64.508MM) and base (\$69.395MM) market assumptions and PLAN J under the high (\$69.959MM) market assumption.

As illustrated in Table 15.2-2, for the low market assumption, PLAN J is 3.6% higher than PLAN F. For the base market assumption, PLAN A is 1.3% higher than PLAN F. For the high market assumption, PLAN A is 4.3% higher than PLAN J.

**Table 15.2-2: Near-Term Plan Results Compared to Lowest-Cost 15 MW PTP Plan**

	Firm Capacity and Reserve Margin					Bilateral Capacity, MISO Point-to-Point Transmission, Operating Reserves					Millions \$ difference from the minimum levelized cost			% difference from the minimum levelized cost		
	Planning Capacity	PPS Peaking	Ashwood Solar	DEI PPA	Reserve Margin	Bilateral Capacity	Dynamic Schedule	MISO PTP	1-in-10 Margin	Net Peak Margin	Low Market	Base Market	High Market	Low Market	Base Market	High Market
Plan A	159	30	54	0	-15.6%	79 15.2%	100 (42 min)	185 (27)	12.2%	6.2%	0.391	0.893	3.022	0.6%	1.3%	4.3%
Plan B	159	90	54	0	7.8%	19 15.2%	100 (42 min)	177 (15)	26.2%	27.6%	0.952	0.804	1.826	1.5%	1.2%	2.6%
Plan C	159	30	54	60	7.8%	19 15.2%	100 (42 min)	177 (15)	9.4%	2.9%	1.932	0.604	0.716	3.0%	0.9%	1.0%
Plan D	159	45	54	45	7.8%	19 15.2%	100 (42 min)	177 (15)	14.7%	9.1%	1.737	0.674	0.989	2.7%	1.0%	1.4%
Plan E	159	60	54	30	7.8%	19 15.2%	100 (42 min)	177 (15)	20.1%	15.2%	1.538	0.746	1.266	2.4%	1.1%	1.8%
Plan F	159	30	86	0	-9.4%	63 15.2%	100 (67 min)	177 (15)	20.9%	2.9%	0.000	0.000	1.639	0.0%	0.0%	2.3%
Plan G	159	75	86	0	8.2%	18 15.2%	100 (67 min)	177 (15)	37.1%	21.4%	0.843	0.355	1.162	1.3%	0.5%	1.7%
Plan H	159	30	86	45	8.2%	18 15.2%	100 (67 min)	177 (15)	20.9%	2.9%	1.626	0.229	0.330	2.5%	0.3%	0.5%
Plan I	159	45	86	30	8.2%	18 15.2%	100 (67 min)	177 (15)	26.3%	9.1%	1.427	0.300	0.606	2.2%	0.4%	0.9%
Plan J	159	40	86	60	18.0%	0 18.0%	100 (67 min)	177 (15)	24.5%	7.0%	2.323	0.460	0.000	3.6%	0.7%	0.0%
Plan K	159	60	86	30	14.1%	3 15.2%	100 (67 min)	177 (15)	31.7%	15.2%	1.708	0.419	0.447	2.6%	0.6%	0.6%

Near-Term 40 MW PTP Plan Comparison

Table 15.2-3 summarizes the 40 MW MISO PTP Plans. The table provides a cost and percentage comparison against the lowest cost plan in each market category – Low, Base, High.

Table 15.2-2: Near-Term Plan Results Compared to Lowest-Cost 40 MW PTP Plan

	Firm Capacity and Reserve Margin					Bilateral Capacity, MISO Point-to-Point Transmission, Operating Reserves					Millions \$ difference from the minimum levelized cost			% difference from the minimum levelized cost		
	Planning Capacity	PPS Peaking	Ashwood Solar	DEI PPA	Reserve Margin	Bilateral Capacity	Dynamic Schedule	MISO PTP	1-in-10 Margin	Net Peak Margin	Low Market	Base Market	High Market	Low Market	Base Market	High Market
Plan A	159	30	54	0	-15.6%	79 15.2%	100 (42 min)	202 (40)	18.3%	13.2%	0.000	0.331	2.464	0.0%	0.5%	3.4%
Plan B	159	90	54	0	7.8%	19 15.2%	100 (42 min)	202 (40)	39.9%	37.9%	1.123	0.802	1.829	1.7%	1.1%	2.5%
Plan C	159	30	54	60	7.8%	19 15.2%	100 (42 min)	202 (40)	18.3%	13.2%	2.103	0.602	0.715	3.2%	0.8%	1.0%
Plan D	159	45	54	45	7.8%	19 15.2%	100 (42 min)	202 (40)	23.7%	19.3%	1.909	0.674	0.989	2.9%	0.9%	1.4%
Plan E	159	60	54	30	7.8%	19 15.2%	100 (42 min)	202 (40)	29.1%	25.5%	1.709	0.746	1.266	2.6%	1.0%	1.8%
Plan F	159	30	86	0	-9.4%	63 15.2%	100 (67 min)	202 (40)	29.9%	13.2%	0.170	0.000	1.640	0.3%	0.0%	2.3%
Plan G	159	75	86	0	8.2%	18 15.2%	100 (67 min)	202 (40)	46.0%	31.7%	1.014	0.355	1.164	1.5%	0.5%	1.6%
Plan H	159	30	86	45	8.2%	18 15.2%	100 (67 min)	202 (40)	29.9%	13.2%	1.796	0.229	0.330	0.2%	0.3%	0.5%
Plan I	159	45	86	30	8.2%	18 15.2%	100 (67 min)	202 (40)	35.3%	19.3%	1.598	0.300	0.606	2.4%	0.4%	0.8%
Plan J	159	40	86	60	18.0%	0 18.0%	100 (67 min)	202 (40)	33.5%	17.3%	2.495	0.459	0.000	3.8%	0.6%	0.0%
Plan K	159	60	86	30	14.1%	3 15.2%	100 (67 min)	202 (40)	40.6%	25.5%	1.880	0.419	0.449	2.8%	0.6%	0.6%



Near-Term Plans - Base Market Comparison

When comparing the near-term plans with base market conditions, shown in Figure 15.2-2, PLAN F (PPS at 30 MW with Ashwood at 86 MW) is the least cost, while PLAN B (PPS at 90 MW with Ashwood at 54 MW) is the highest cost. The step change in price, which occurs in planning year 22/23 for all 11 plans, is due to KYMEA's portfolio transition from higher fixed costs with lower secured energy costs to more a market reliant portfolio which reduces the fixed cost and increases the energy costs.

The range of outcomes is \$1MM per year between the lowest and highest cost plans.

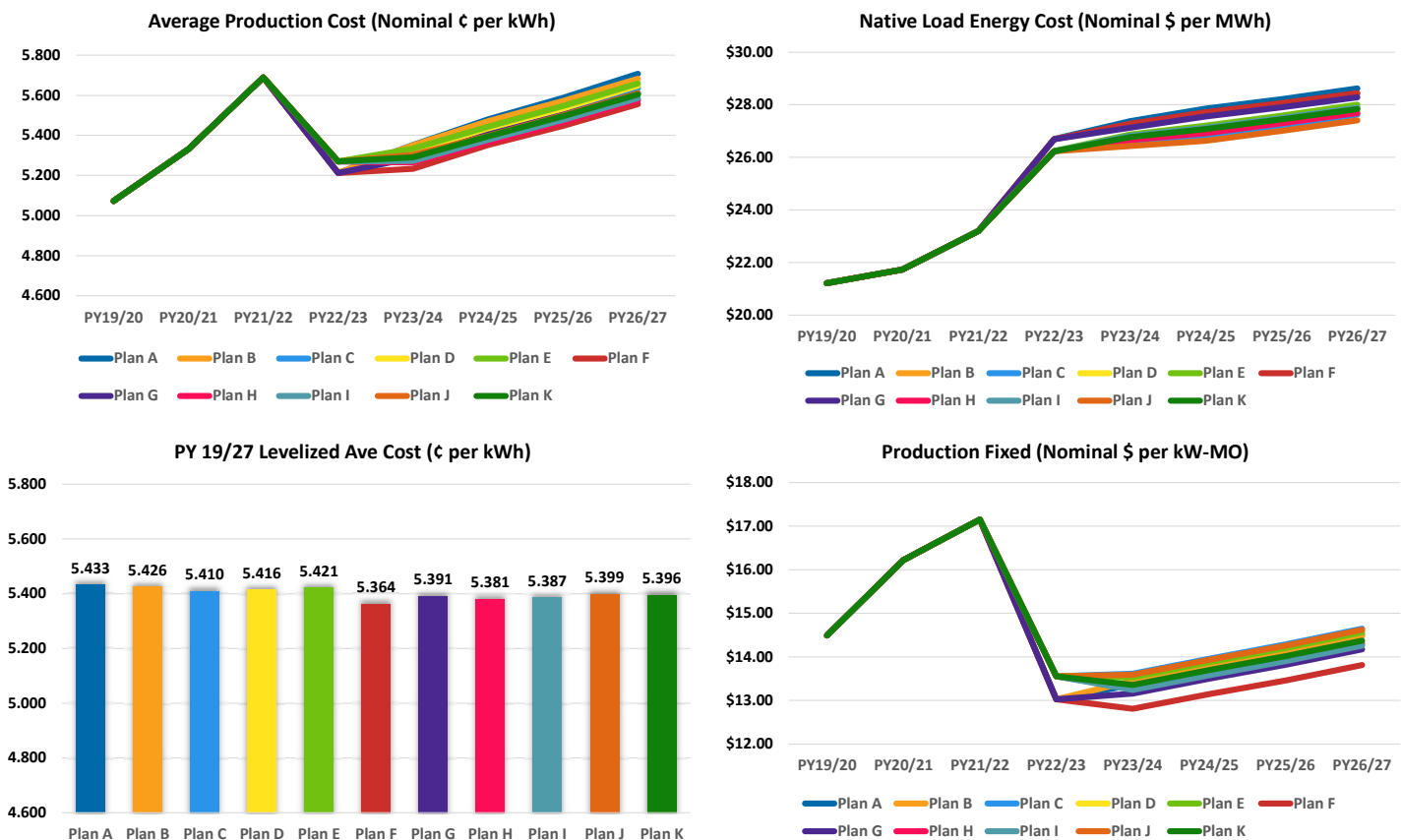


Figure 15.2-2: Near-Term Plans - Base Market Comparison



Market Sensitivity

The Market Sensitivity analysis examined the effects of the 11 plans when changes are made in natural gas, energy price, and capacity price sensitivities. The sensitivity cases were designed to capture the extremes for the entire near-term study period. For the low market case, the prices start low and stay low. For the high market case, the prices start high and stay high. Figure 15.2-3 illustrates the trade-off between PLAN F, which has the lowest expected value under base market conditions, and PLAN J, which has the lowest risk.

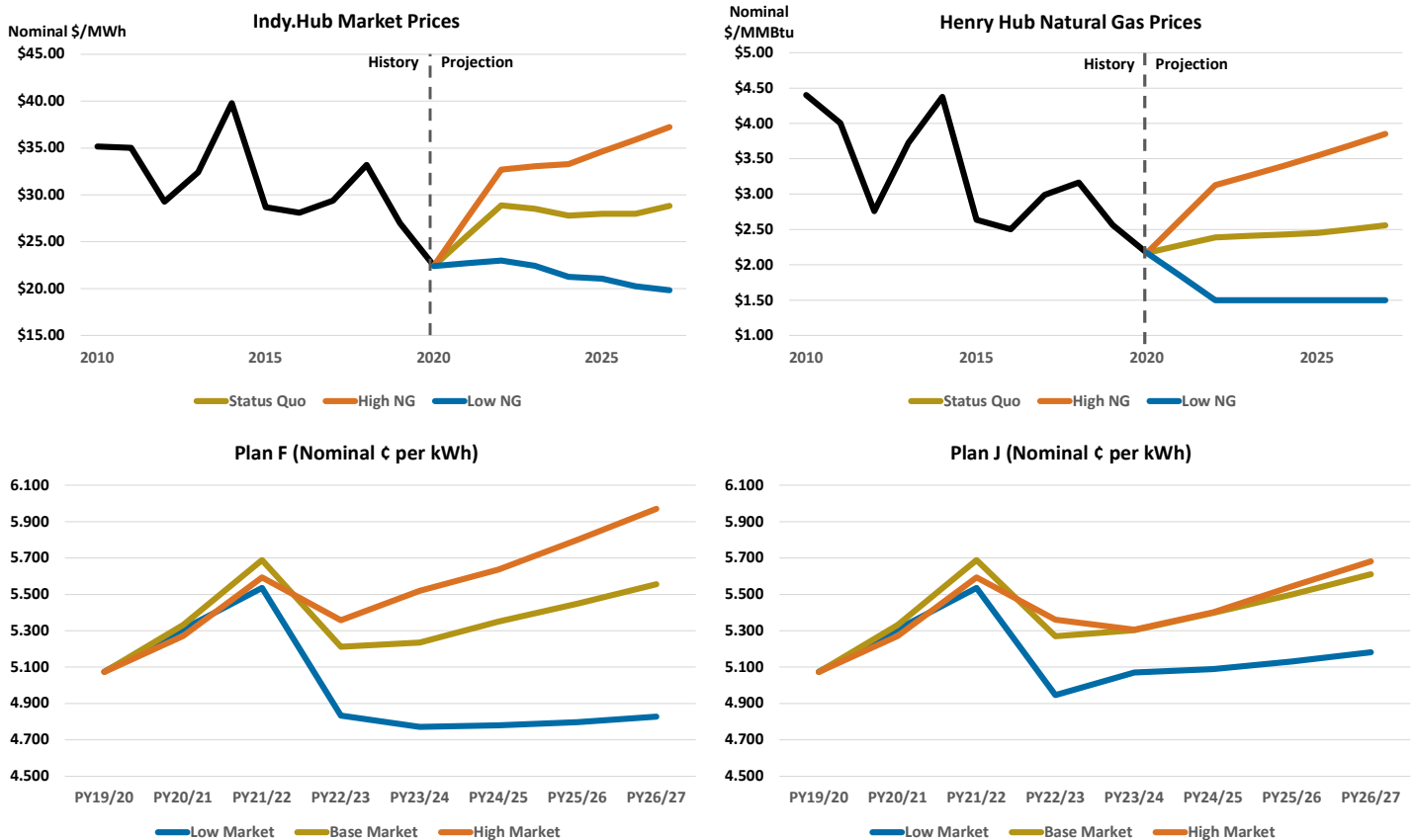


Figure 15.2-3: Near-Term Plans - Lowest Cost and Lowest Risk



Near-Term Plans - Low Market Comparison

When comparing the near-term plans with low market conditions, shown in Figure 15.2-4, PLAN F (PPS at 30 MW with Ashwood at 86 MW) is the least cost while PLAN J (PPS at 40 MW, Ashwood at 86 MW, DEI at 60 MW) is the highest cost. PLAN F has more unhedged market exposure, so under low market conditions, PLAN F fares best, as it is better positioned to take advantage of low market prices.

The range of outcomes is \$2.3MM per year between the lowest and highest cost plans.



Figure 15.2-4: Near-Term Plans - Low Market Comparison



Near-Term Plans - High Market Comparison

When comparing the near-term plans with high market conditions, shown in Figure 15.2-5, PLAN J (PPS at 40 MW, Ashwood at 86 MW, DEI at 60 MW) is the least cost while PLAN A (PPS at 30 MW with Ashwood at 54 MW) is the highest cost. PLAN J is hedged the most against market exposure; so, under high market conditions, PLAN J fares best.

The range of outcomes is \$2.7MM per year between the lowest and highest cost plans.

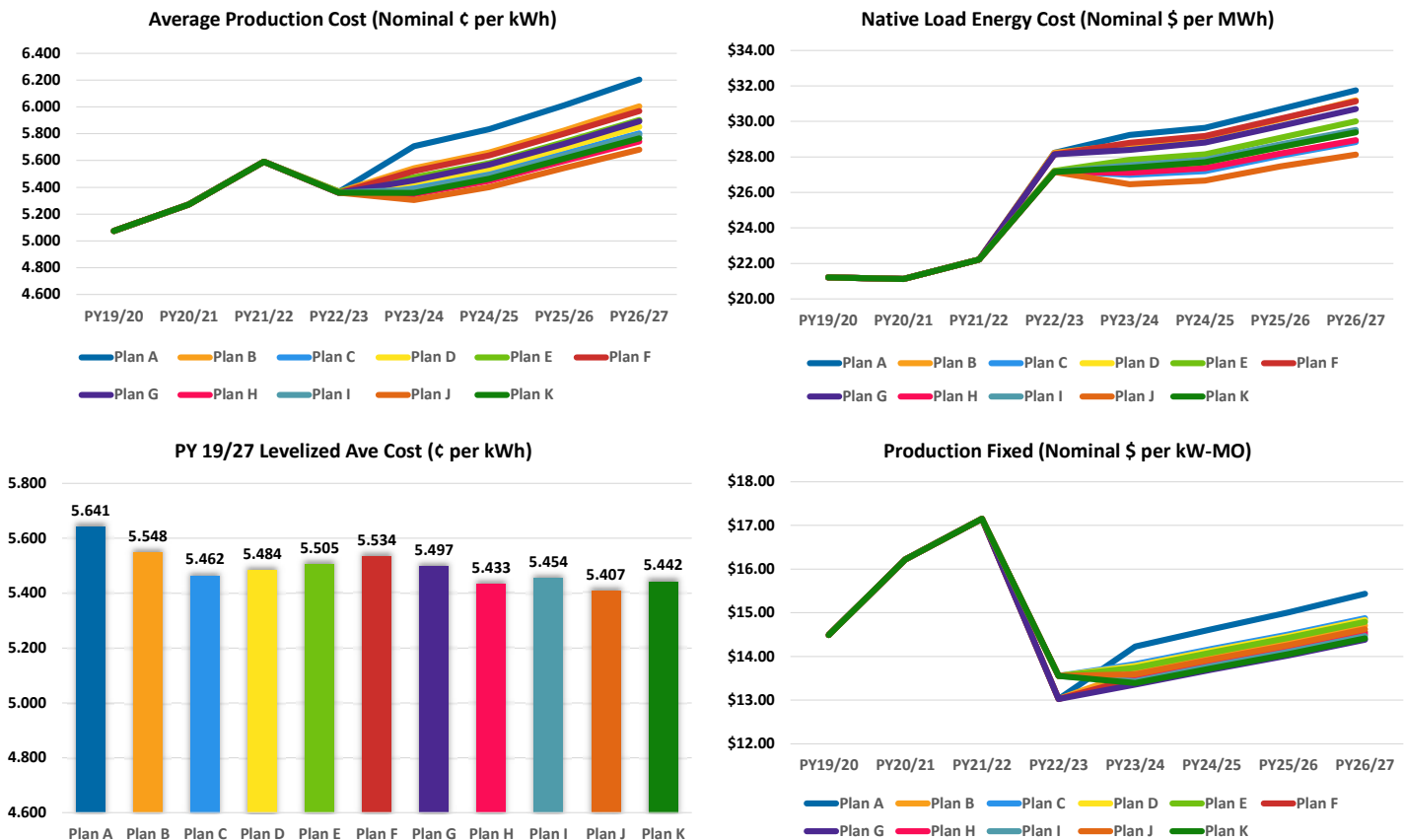


Figure 15.2-5: Near-Term Plans - High Market Comparison



Near-Term Plans – Floating Bars

To compare the risk of the high-base-low sensitivities in Figure 15.2-6, a floating bar chart was prepared to provide a ranking by risk. The floating bar chart is not to be confused with the tornado chart described in Section 14. The length of the black bar represents market opportunity. The farther left the bar, the greater the savings. The length of the red bar represents market risk—the farther right the bar, the greater the cost. The overall width of the bar represents the market exposure, either good or bad. The intersection of the black and red bars is the base or expected outcome.

Not surprisingly, PLAN A (PPS Peaking 30 MW, Ashwood Solar 54 MW), which relies heavily on the market, has the largest market exposure. While PLAN J (PPS Peaking 40 MW, Ashwood Solar 86 MW, DEI 60 MW), which is far more hedged, has the lowest market exposure but also the least market opportunity.



Figure 15.2-6: Near-Term Plans - Expected Value and Market Risk Ranking



Near-Term Plans – Efficient Frontier

In modern portfolio theory, the efficient frontier is an investment portfolio that occupies the "efficient" parts of the risk-return spectrum. An efficient frontier diagram, shown in Figure 15.2-7, plots the standard deviation on the x-axis and the average production cost (APC) on the y-axis for each plan. The standard deviation of APC is a measure of the risk of the plan.

The lower-left quadrant of this diagram is the preferred area as that area has the lowest risk and the lowest APC. The upper-right quadrant is the least desirable as it has the highest risk and highest APC.

The purpose of the efficient frontier is to provide a risk-return visual image. The efficient frontier does not include solar generation intermittency imbalance concerns, flexibility of adding Benham and Berea, and operational risks, which are described in Section 16 of this report. As illustrated in Figure 15.2-7, PLANs H and I provide the closest balance between risk and cost. PLAN A has the highest cost and the highest risk. PLAN J has the lowest risk. PLAN F has the lowest cost. Certain plans, such as PLANs B, E, G, and K, have a higher level of PPS Peakers which provides an additional layer of LKE internal BA reliability with less reliance on the MISO energy and capacity market. For ease of comparison, the Ashwood size for each plan is highlighted in the plan's bubble.

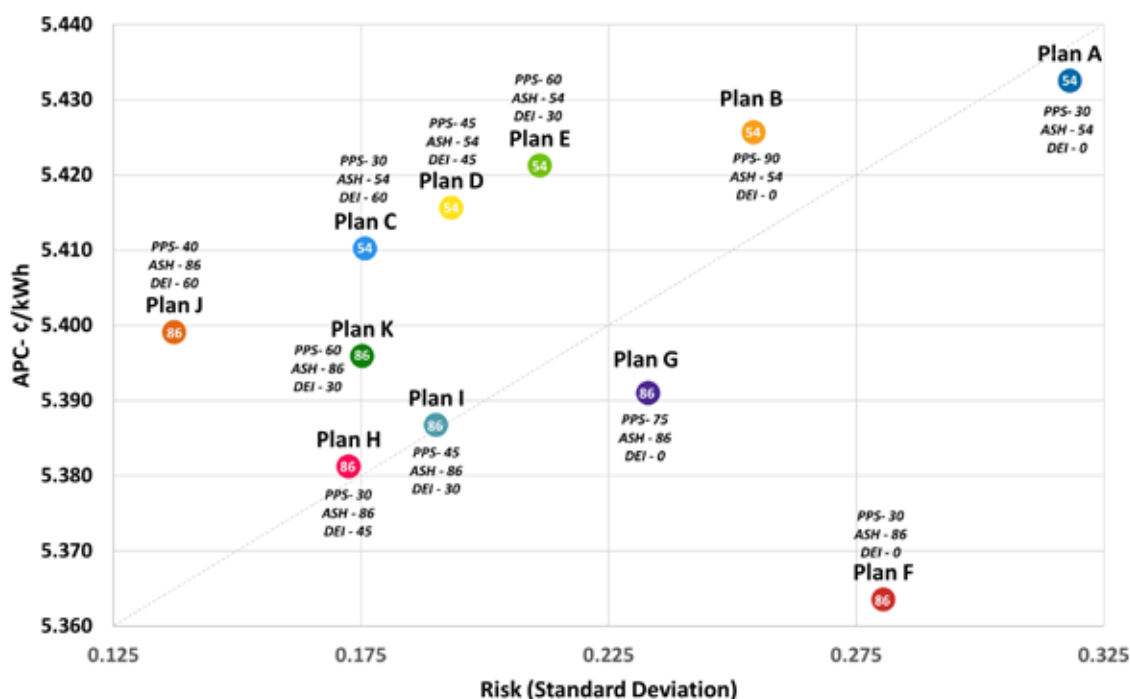


Figure 15.2-7: Near-Term Plans - Efficient Frontier



Near-Term Plans – Reliability

To confirm that the near-term plans provide enough energy to serve KYMEA's peak load plus losses in the LKE transmission system under extreme weather conditions, the Agency performs an operating reserve analysis. The analysis utilizes the 1-in-10 peak demand forecast described in Section 5 (Load Forecast), also known as 90/10 load probability forecast. Operating reserve analysis for KYMEA's load in the PJM (EKPC) RTO is not required as PJM is responsible for serving all load inside PJM.

The ability to serve load considers the summer and winter peak seasons, daylight and evening hours, and N-1 contingency. The N-1 contingency analysis is performed to confirm KYMEA has sufficient operating reserves after the single largest contingency. In this instance, the single largest contingency was deemed to be a complete forced outage of the PPS peaking capacity combined with a 20% derate of the expected solar output during the analyzed peak hour. The operating reserve analysis focused on the last year of the near-term evaluation period, which is planning year 2026/2027.

Operating Reserve Analysis with Minimum MISO PTP

The MISO point-to-point firm transmission reservation requirement is shown for each of the 11 plans in Table 15.2-3. The six far right columns show the percent operating reserves for the different seasons and time frames. A negative percentage means there is not enough resources plus firm MISO point-to-point transmission to serve the peak load plus losses. The Table 15.2-3 operating reserve analysis illustrates KYMEA is unable to serve load under an N-1 contingency during certain seasons and time frames under the minimal MISO PTP transmission reservation.

Table 15.2-3: Near-Term Plan N-1 Contingency Operating Reserve (Minimum MISO PTP)

	Firm Capacity + PRA and Reserve Margin (Planning Year 2026/2027)						1-in-10 Peak		Operating Reserve All Units Available			Operating Reserve PPS FO, Ashwood 20% Derate		
	50/50 Peak	Capacity	PRA	Capacity + PRA	Reserve Margin	MISO PTP	Summer	Winter	Summer Daylight	Summer Evening	Winter	Summer Daylight	Summer Evening	Winter
Plan A	262	216	86	302	15.4%	185	280	246	8.4%	25.4%	1.8%	-6.1%	8.6%	-10.4%
Plan B	262	276	48	324	23.8%	177	280	246	29.8%	50.1%	26.2%	-6.1%	8.6%	-10.4%
Plan C	262	276	26	302	15.4%	177	280	246	8.4%	25.4%	1.8%	-6.1%	8.6%	-10.4%
Plan D	262	276	26	302	15.4%	177	280	246	13.8%	31.6%	7.9%	-6.1%	8.6%	-10.4%
Plan E	262	276	26	302	15.4%	177	280	246	19.1%	37.8%	14.0%	-6.1%	8.6%	-10.4%
Plan F	262	232	77	309	18.1%	177	280	246	19.9%	38.7%	1.8%	3.1%	19.2%	-10.4%
Plan G	262	277	77	354	35.3%	177	280	246	36.0%	57.2%	20.1%	3.1%	19.2%	-10.4%
Plan H	262	277	32	309	18.1%	177	280	246	19.9%	38.7%	1.8%	3.1%	19.2%	-10.4%
Plan I	262	277	47	324	23.9%	177	280	246	25.3%	44.9%	7.9%	3.1%	19.2%	-10.4%
Plan J	262	302	17	319	22.0%	177	280	246	23.5%	42.8%	5.9%	3.1%	19.2%	-10.4%
Plan K	262	292	47	339	29.6%	177	280	246	30.6%	51.1%	14.0%	3.1%	19.2%	-10.4%



Operating Reserve Analysis with Maximum MISO PTP

In order to analyze KYMEA's inability to serve load under an N-1 contingency, the MISO point-to-point firm transmission reservation was increased to 202 MW as shown in Table 15.2-4. By bringing the MISO PTP to 202 MW, KYMEA can serve load under the harshest weather, even if the PPS peaking capacity is unavailable and the solar generation is 20% derated below expected output.

In this instance, the trade-off is between the probability of an N-1 contingency and the added cost of securing an additional 25 MW of MISO PTP transmission. From Table 15.2-1, the additional cost of transmission to serve the 1-in-10 peak under an N-1 contingency is nearly \$1.7MM per year.

Table 15.2-4: Near-Term Plan N-1 Contingency Operating Reserve (Maximum MISO PTP)

	Firm Capacity + PRA and Reserve Margin (Planning Year 2026/2027)						1-in-10 Peak		Operating Reserve All Units Available			Operating Reserve PPS FO, Ashwood 20% Derate		
	50/50 Peak	Capacity	PRA	Capacity + PRA	Reserve Margin	MISO PTP	Summer	Winter	Summer Daylight	Summer Evening	Winter	Summer Daylight	Summer Evening	Winter
Plan A	262	216	86	302	15.4%	202	280	246	17.3%	35.7%	12.0%	2.8%	18.9%	-0.2%
Plan B	262	276	48	324	23.8%	202	280	246	38.7%	60.4%	36.4%	2.8%	18.9%	-0.2%
Plan C	262	276	26	302	15.4%	202	280	246	17.3%	35.7%	12.0%	2.8%	18.9%	-0.2%
Plan D	262	276	26	302	15.4%	202	280	246	22.7%	41.9%	18.1%	2.8%	18.9%	-0.2%
Plan E	262	276	26	302	15.4%	202	280	246	28.0%	48.1%	24.2%	2.8%	18.9%	-0.2%
Plan F	262	232	77	309	18.1%	202	280	246	28.8%	49.0%	12.0%	12.0%	29.5%	-0.2%
Plan G	262	277	77	354	35.3%	202	280	246	44.9%	67.6%	30.3%	12.0%	29.5%	-0.2%
Plan H	262	277	32	309	18.1%	202	280	246	28.8%	49.0%	12.0%	12.0%	29.5%	-0.2%
Plan I	262	277	47	324	23.9%	202	280	246	34.2%	55.2%	18.1%	12.0%	29.5%	-0.2%
Plan J	262	302	17	319	22.0%	202	280	246	32.4%	53.1%	16.1%	12.0%	29.5%	-0.2%
Plan K	262	292	47	339	29.6%	202	280	246	39.6%	61.4%	24.2%	12.0%	29.5%	-0.2%



Benham and Berea – AR Project Near-Term Analysis

While it is not yet known whether Benham and/or Berea will join the AR Project, the development of the near-term plans included additional consideration and analysis to determine if the plan(s) are flexible enough to accommodate Benham and/or Berea if they chose to join the AR Project in 2024.

Capacity and Transmission Mutual Benefits

Benham and Berea are both winter peaking utilities, while the current AR Project members are summer peaking. Adding Benham and Berea creates a mutual benefit as capacity and transmission secured by Benham and Berea to satisfy their winter peak becomes available for the AR Project to satisfy its summer peak and vice versa. The balancing between summer and winter peaks is a mutual benefit for both entities, saving over \$500,000 in MISO PTP transmission cost annually. Figure 15.2-8 illustrates the combined monthly peak demand.

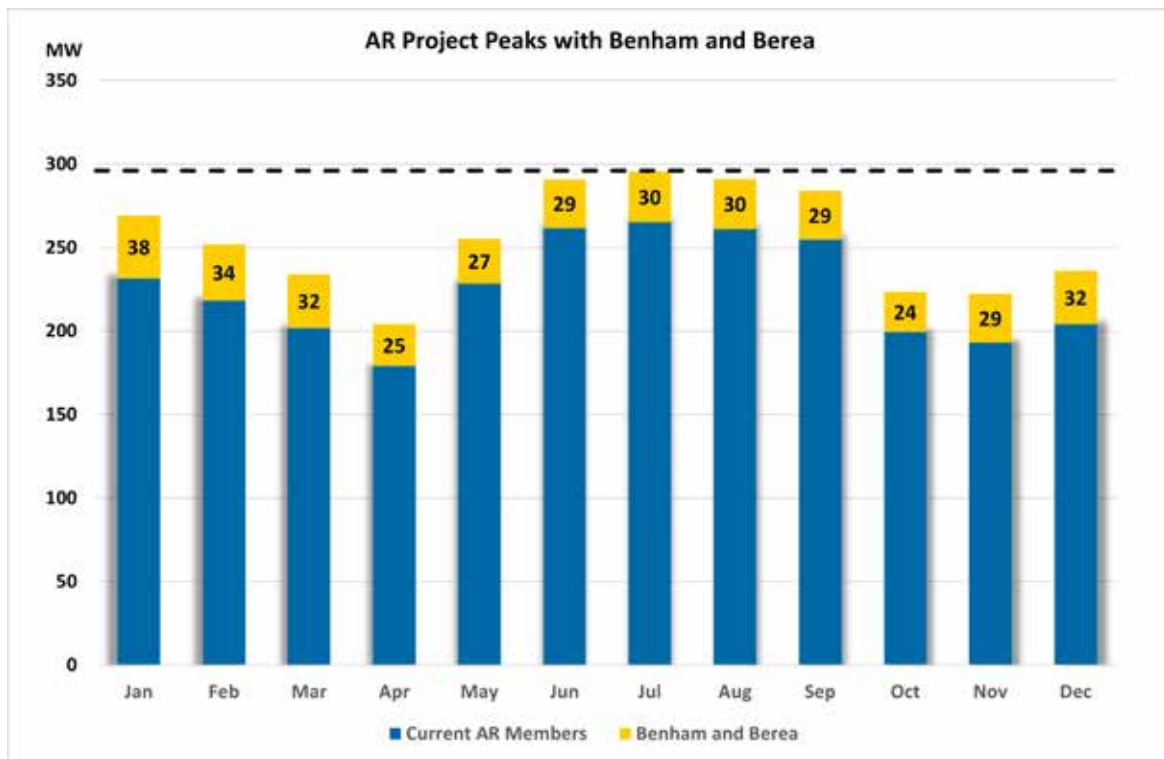


Figure 15.2-8: AR Project Peaks with Benham and Berea

Economies of Scale Mutual Benefits

Simply stated, economies of scale means doing things more efficiently or obtaining greater buying power with increased size. Adding Benham and Berea would increase KYMEA's total energy 10%. The increased size would allow KYMEA to be a participant in larger generation projects, resulting in a more efficient cost for the project.



15.3 Long-Term Plan Evaluation

As discussed in Section 13, Plan Development, 4 long-term plans were developed. The long-term evaluation focused on possible future plans. The purpose of the evaluation was to assess how each long-term plan would perform under the nine plausible scenarios.

Long-Term Plan Results

The results, expressed in levelized average cost in ¢/kWh, of the four long-term plans with the nine scenarios are provided in Table 15.3-1. Each plan was simulated under the scenario's market conditions described in Section 12 (Scenario Results). Additional detail of each plan is provided in the remaining pages of Section 15.

Table 15.3-1: Long-Term Plan Results (levelized ¢/kWh)

Scenario	Long-Term Plan			
	Plan 1: CC Plan	Plan 2: RICE Plan	Plan 3: Net Zero Plan	Plan 4: Market Plan
Status Quo	6.504	6.241	7.395	6.309
High NG	7.081	6.838	7.587	6.992
Low NG	5.975	5.646	7.322	5.801
High Demand	6.496	6.225	7.386	6.315
Low Demand	6.512	6.253	7.433	6.336
Zero Carbon Additions	6.625	6.377	7.507	6.568
High NG w/ CO2 Limit	7.382	6.745	7.762	7.351
Low NG w/ CO2 Limit	6.573	5.771	7.400	6.317
Carbon Tax	7.807	7.032	8.032	7.490

Long-Term Plan Results Comparison

PLAN 2 (RICE Plan) was the least-cost under all nine scenarios. The other long-term plans are compared to PLAN 2 in Table 15.3-2.

Table 15.3-2: Long-Term Plan Results as Percentage of Least-Cost Plan

Scenario	Long-Term Plan			
	Plan 1: CC Plan	Plan 2: RICE Plan	Plan 3: Net Zero Plan	Plan 4: Market Plan
Status Quo	4.2%	0.0%	18.5%	1.1%
High NG	3.6%	0.0%	11.0%	2.3%
Low NG	5.8%	0.0%	29.7%	2.7%
High Demand	4.4%	0.0%	18.7%	1.4%
Low Demand	4.1%	0.0%	18.9%	1.3%
Zero Carbon Additions	3.9%	0.0%	17.7%	3.0%
High NG w/ CO2 Limit	9.5%	0.0%	15.1%	9.0%
Low NG w/ CO2 Limit	13.9%	0.0%	28.2%	9.5%
Carbon Tax	11.0%	0.0%	14.2%	6.5%



Illustrated in Figure 15.3-2, the levelized average production cost of the CC Plan across the nine scenarios varies from a low of 5.975 to a high of 7.807. The lower-left figure is a bar chart ranking of the levelized average cost.

Time series views of the average production cost in ¢ per kWh (upper-left), the native load energy cost in \$ per MWh (upper-right), and the production fixed cost in \$ per kW-MO (lower-right) illustrate how the plan costs change over time under each scenario.

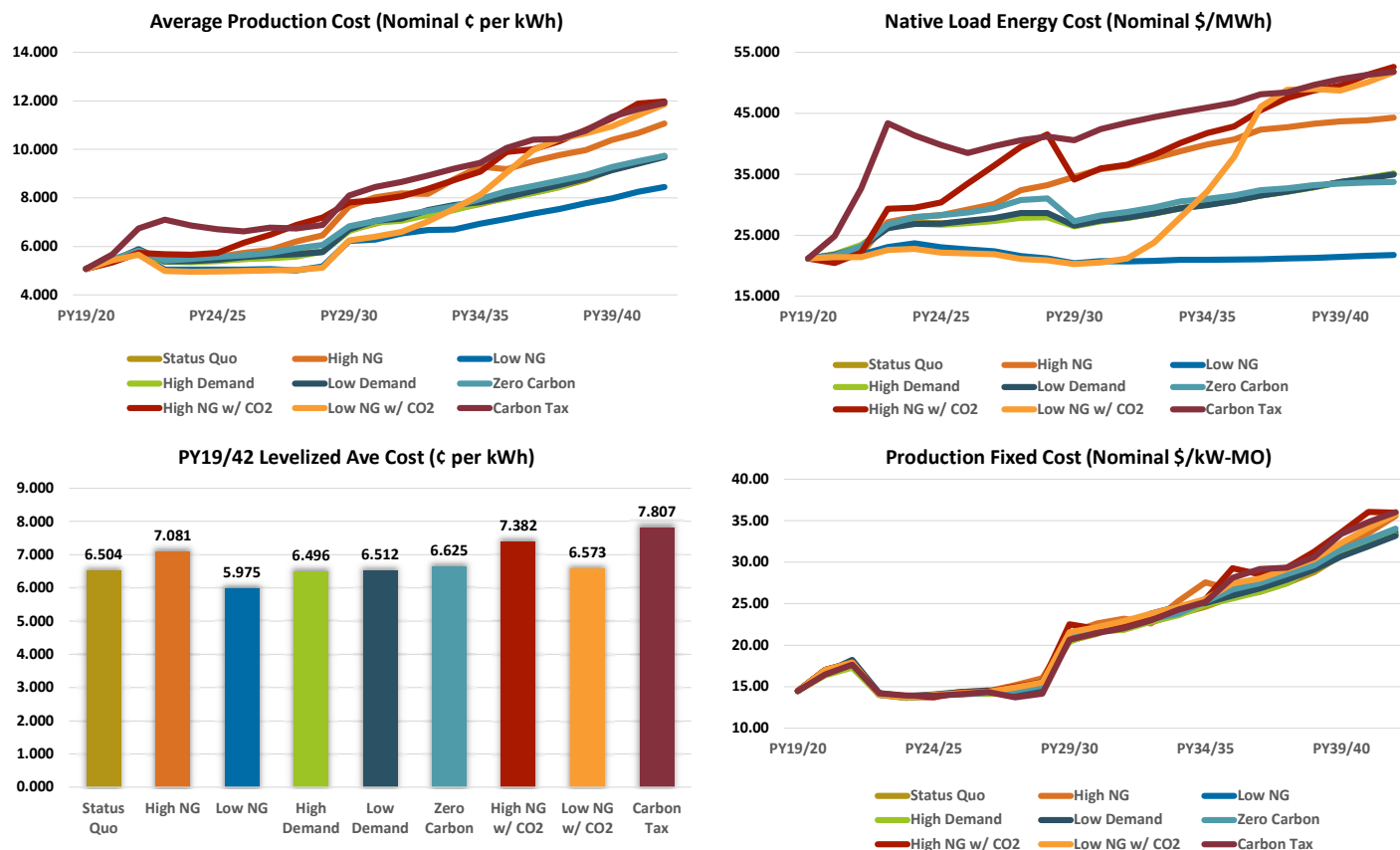


Figure 15.3-2: Long-Term PLAN 1: CC Results

The fixed costs are relatively stable, but increasing across the nine scenarios. The steady increase is driven by expected increases in MISO PTP transmission. The energy cost is not stable and varies widely across the scenarios due to natural gas price, market price, and carbon cost and limit uncertainty.



Long-Term PLAN 2: RICE Plan

RICE Plan Summary: The RICE Plan calls for 156 MW participation in reciprocating internal combustion engines (RICE) units and 50 MW of new solar in LKE, both in 2029.

Figure 15.3-3 illustrates that the 156 MW would be built in the LKE system. It was assumed excess RICE generation could not be sold into MISO, as the plan did not include costs for firm transmission out of LKE to MISO; however, it is likely some of the excess low-cost RICE energy could be sold into MISO on a non-firm basis. The advantage of the RICE units is their ability to start and stop very easily if the non-firm transmission path schedule gets cut.

The 104 MW of solar generation plus 32 MW of SEPA hydro puts KYMEA's carbon-free energy at 22% of its native load. In this plan, KYMEA would need to secure an additional 59 MW of capacity to meet a 15% reserve margin plus 81 MW of MISO PTP transmission to maintain 8% operating reserves for a 1-in-10 peak demand.

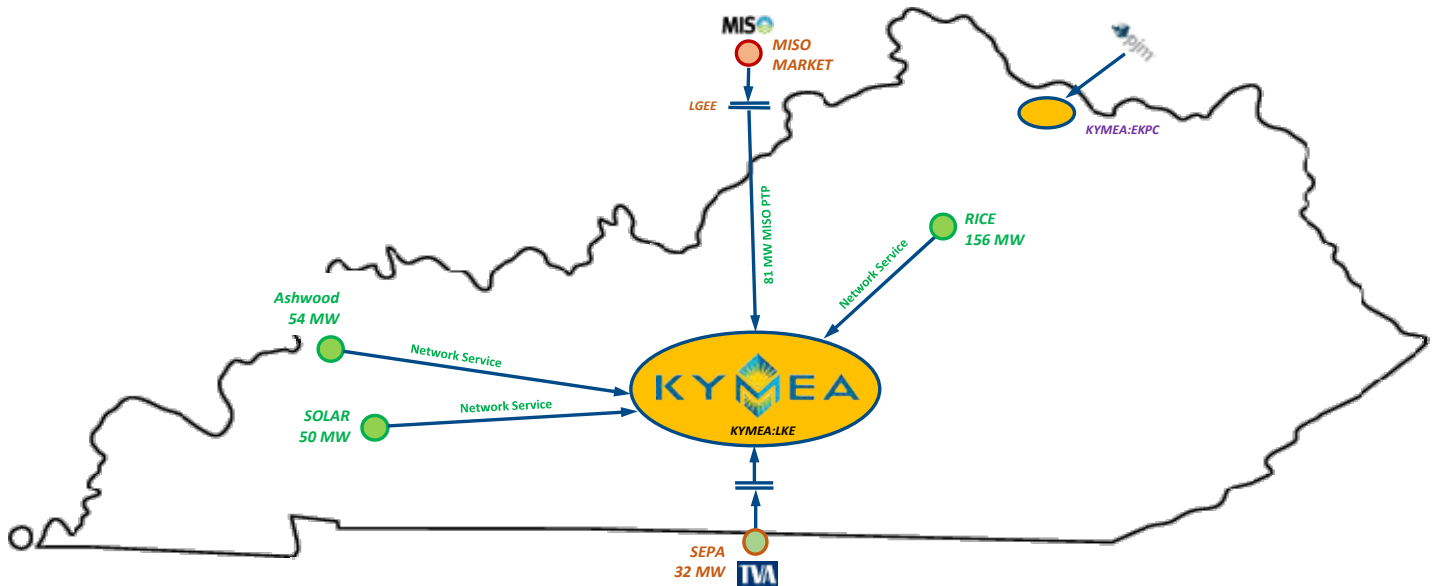


Figure 15.3-3: Long-Term PLAN 2: RICE Map



Illustrated in Figure 15.3-4, the levelized average production cost of the RICE Plan across the nine scenarios varies from a low of 5.646 to a high of 7.032. The lower-left figure is a bar chart ranking of the levelized average cost.

Time series views of the average production cost in ¢ per kWh (upper-left), the native load energy cost in \$ per MWh (upper-right), and the production fixed cost in \$ per kW-MO (lower-right) illustrate how the plan costs change over time under each scenario. The RICE Plan is the least-cost among the four analyzed long-term plans across all nine scenarios.

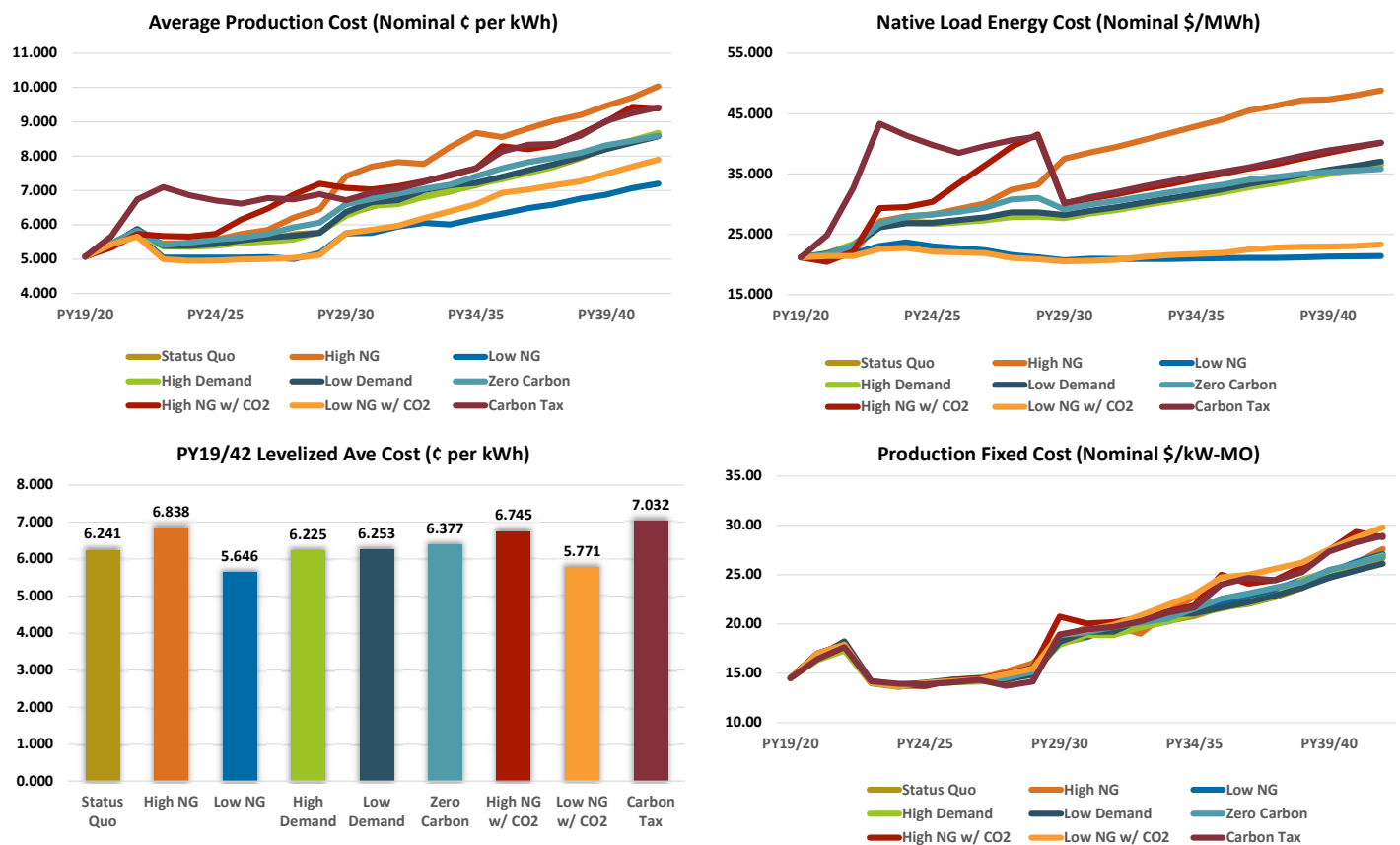


Figure 15.3-4: Long-Term PLAN 2: RICE Results

The fixed graphs are relatively stable, but increasing across the 9 scenarios. The increase is due to increasing RICE unit O&M and expected increases in MISO PTP transmission. Since the RICE units are internal to the LKE system, PLAN 2 has less interaction with the MISO market, so certain scenarios such as low natural gas with national carbon limits doesn't exhibit the same energy cost bounce as was seen in PLAN 1. This plan is most susceptible to high natural gas prices and a carbon tax.



Long-Term PLAN 3: Market Plan

Market Plan Summary: The Market Plan calls for only MISO and PJM market purchases beginning in 2029. Given the large market exposure of this plan, standardized 5x16 and 7x24 hedge products were assumed to off-set the market risk. Figure 15.3-5 illustrates that the plan requires 237 MW of MISO firm point-to-point transmission service.

The 104 MW of solar generation plus 32 MW of SEPA hydro puts KYMEA's carbon-free energy at 22% of its native load. In this plan, KYMEA would need to secure an additional 214 MW of capacity to meet a 15% reserve margin plus 237 MW of MISO PTP transmission to maintain 8% operating reserves for a 1-in-10 peak demand.

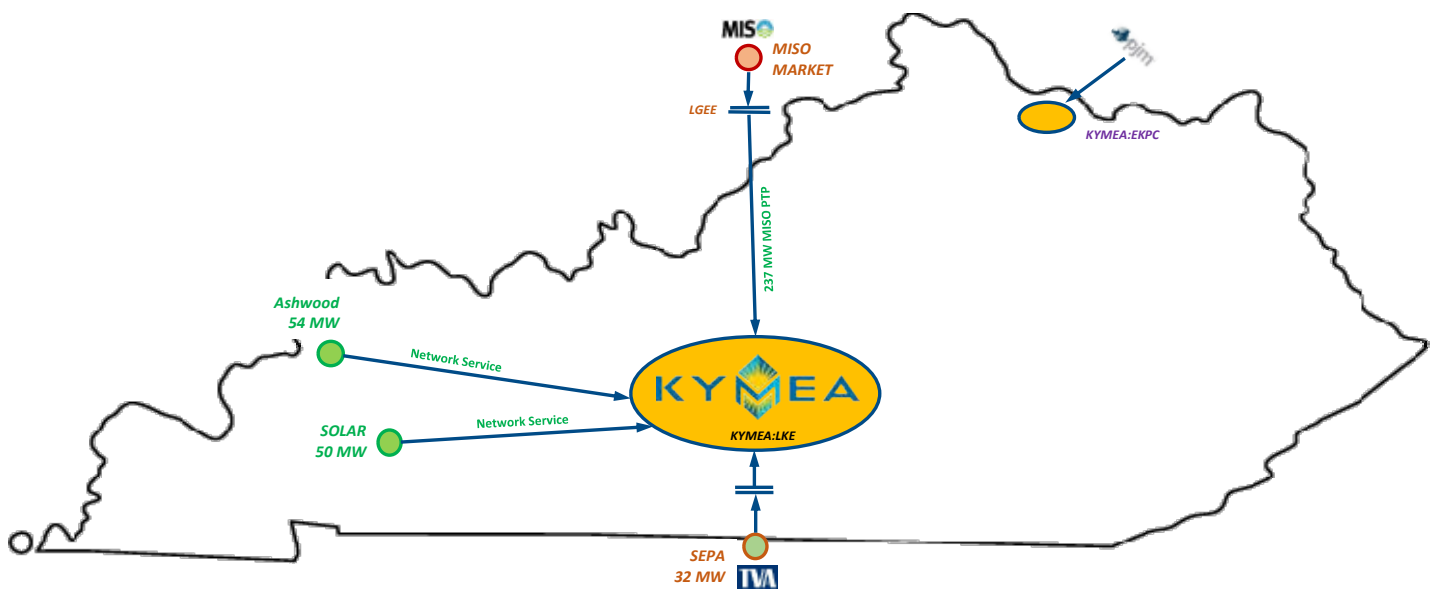


Figure 15.3-5: Long-Term PLAN 3: Market Map



Illustrated in Figure 15.3-6, the levelized average production cost of the Market Plan across the nine scenarios varies from a low of 5.801 to a high of 7.490. The lower-left figure is a bar chart ranking of the levelized average cost.

Time series views of the average production cost in ¢ per kWh (upper-left), the native load energy cost in \$ per MWh (upper-right), and the production fixed cost in \$ per kW-MO (lower-right) illustrate how the plan costs change over time under each scenario.

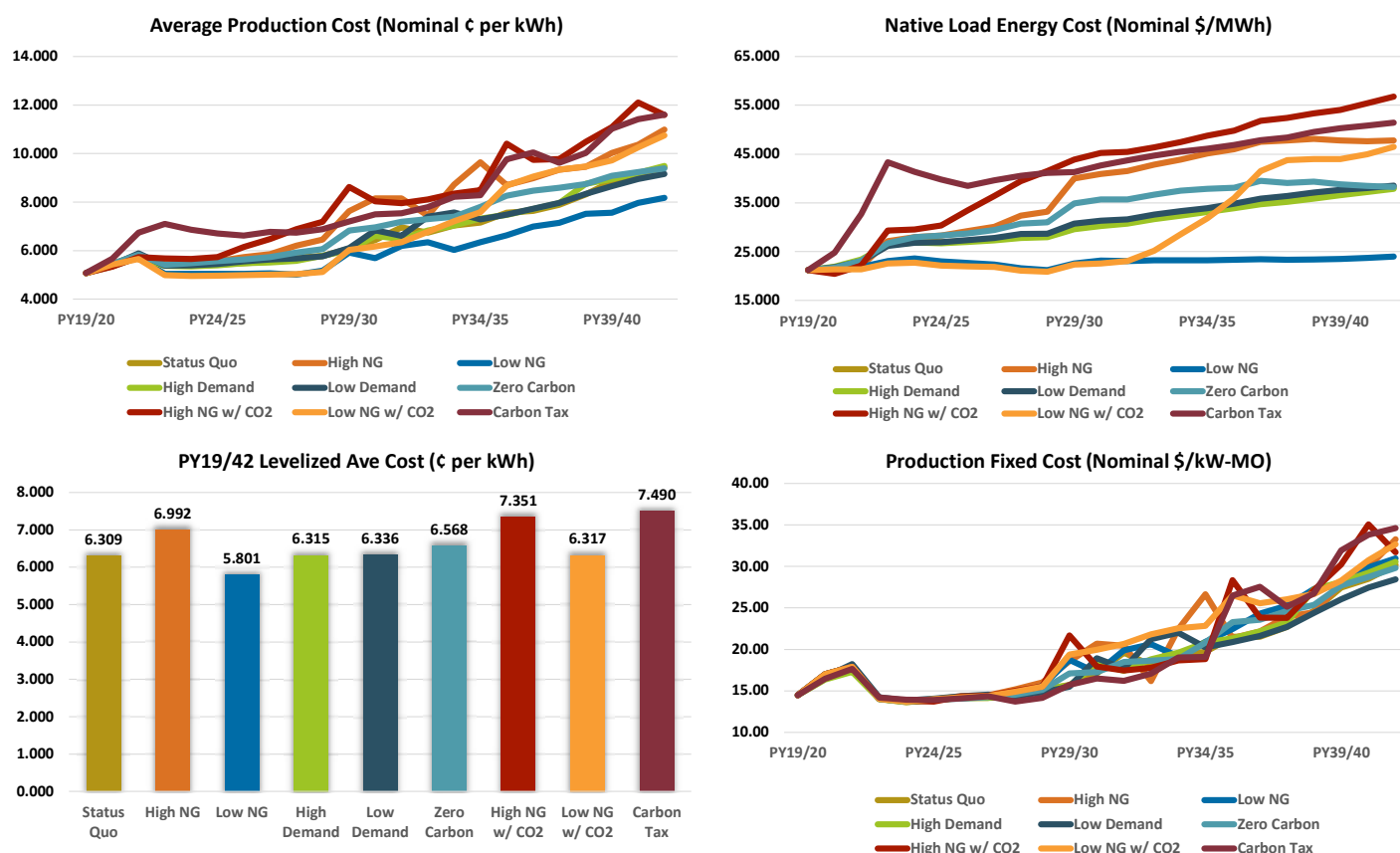


Figure 15.3-6: Long-Term PLAN 3: Market Results

The Market Plan (PLAN 3) exhibits much of the same behavior as the Combined Cycle Plan (PLAN 1). This is not surprising as the future marginal cost of the Market Plan scenarios are closely tied to combined cycle natural gas generation. The fixed costs are more volatile as the cost of capacity is tied to the market and is not hedged.



Long-Term PLAN 4: Net Zero Plan

Net Zero Plan Summary: The Net Zero Plan, illustrated in Figure 15.3-7, calls for 325 MW participation in a large wind farm in 2029 located in MISO Zone 6 (Indiana-Kentucky), and 77 MW of new solar in LKE in 2029. KYMEA's solar (Ashwood + new solar) would be paired with 78 MW of battery storage. In this plan, KYMEA would be carbon neutral by 2030.

The 325 MW of wind, 131 MW of solar generation, and 32 MW of SEPA hydro puts KYMEA's carbon-free energy at 106% of its native load. In this plan, KYMEA would need to secure an additional 176 MW of capacity to meet a 15% reserve margin plus 237 MW of MISO PTP transmission to maintain 8% operating reserves for a 1-in-10 peak demand.

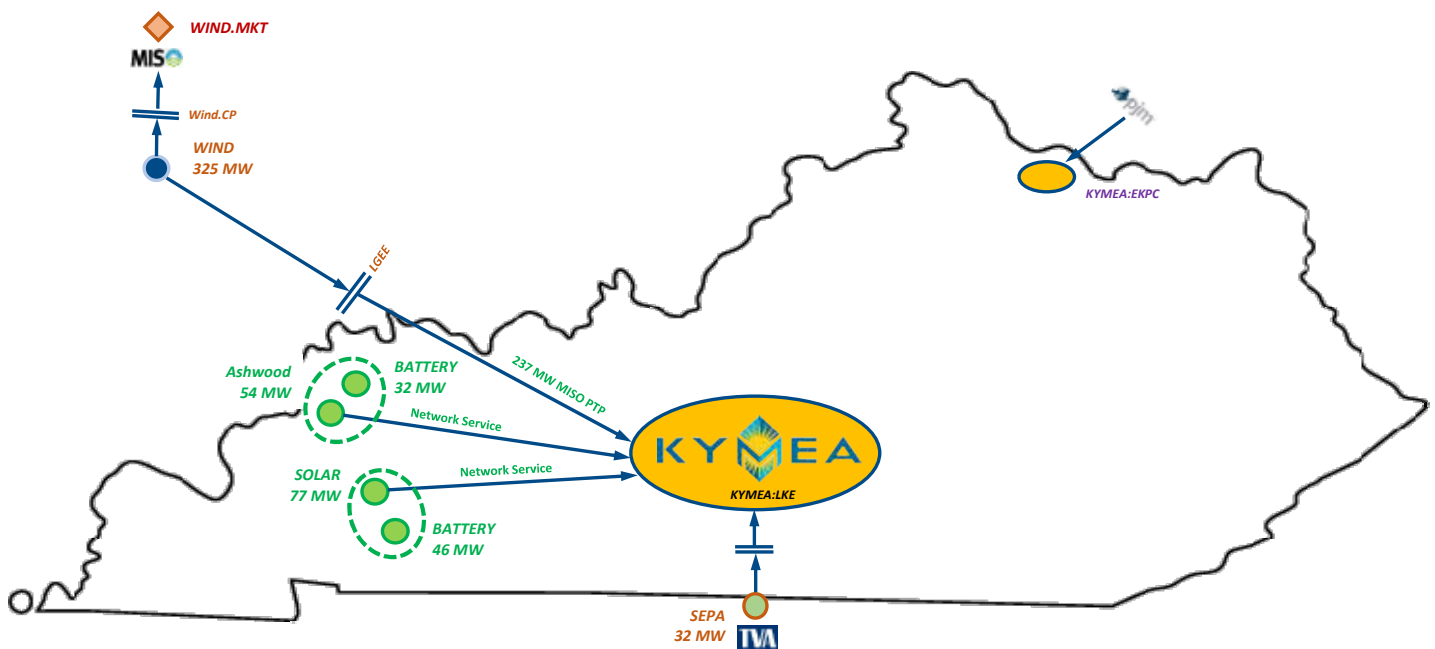


Figure 15.3-7: Long-Term PLAN 4: Net Zero Map



Illustrated in Figure 15.3-8, the levelized average production cost of the Net Zero Plan across the nine scenarios varies from a low of 7.322 to a high of 8.032. The lower-left figure is a bar chart ranking of the levelized average cost.

Time series views of the average production cost in ¢ per kWh (upper-left), the native load energy cost in \$ per MWh (upper-right), and the production fixed cost in \$ per kW-MO (lower-right) illustrate how the plan costs change over time under each scenario. The Net Zero plan is significantly higher in cost than the other three long-term plans.

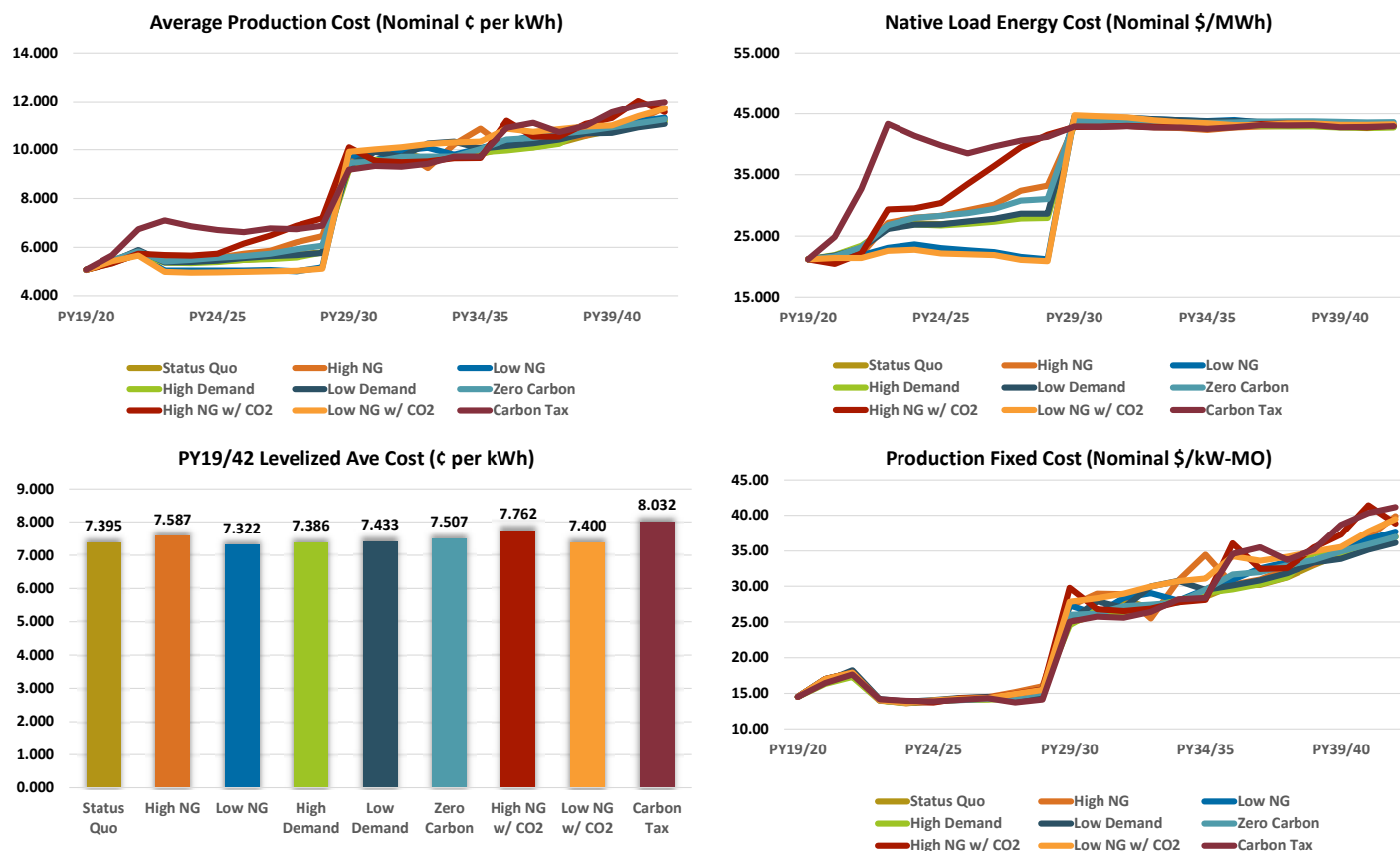


Figure 15.3-8: Long-Term PLAN 4: Net Zero Results

Not surprisingly, the energy cost of the Net Zero Plan is very stable across the nine scenarios since the energy price is not influenced by fuel price or carbon costs.



Net Zero Plan Battery Utilization

The Net Zero Plan includes 78 MW of 4-hour batteries paired with solar. The batteries charge and discharge differently by season, as illustrated in Figure 15.3-9.

- **Summer Season:** The batteries will charge in the morning to early afternoon and discharge across the evening peak.
- **Winter Season:** The batteries will charge in the afternoon and discharge across the morning and evening peaks.
- **Spring and Fall Season:** The batteries will charge across the entire daylight period and discharge in the non-daylight periods.

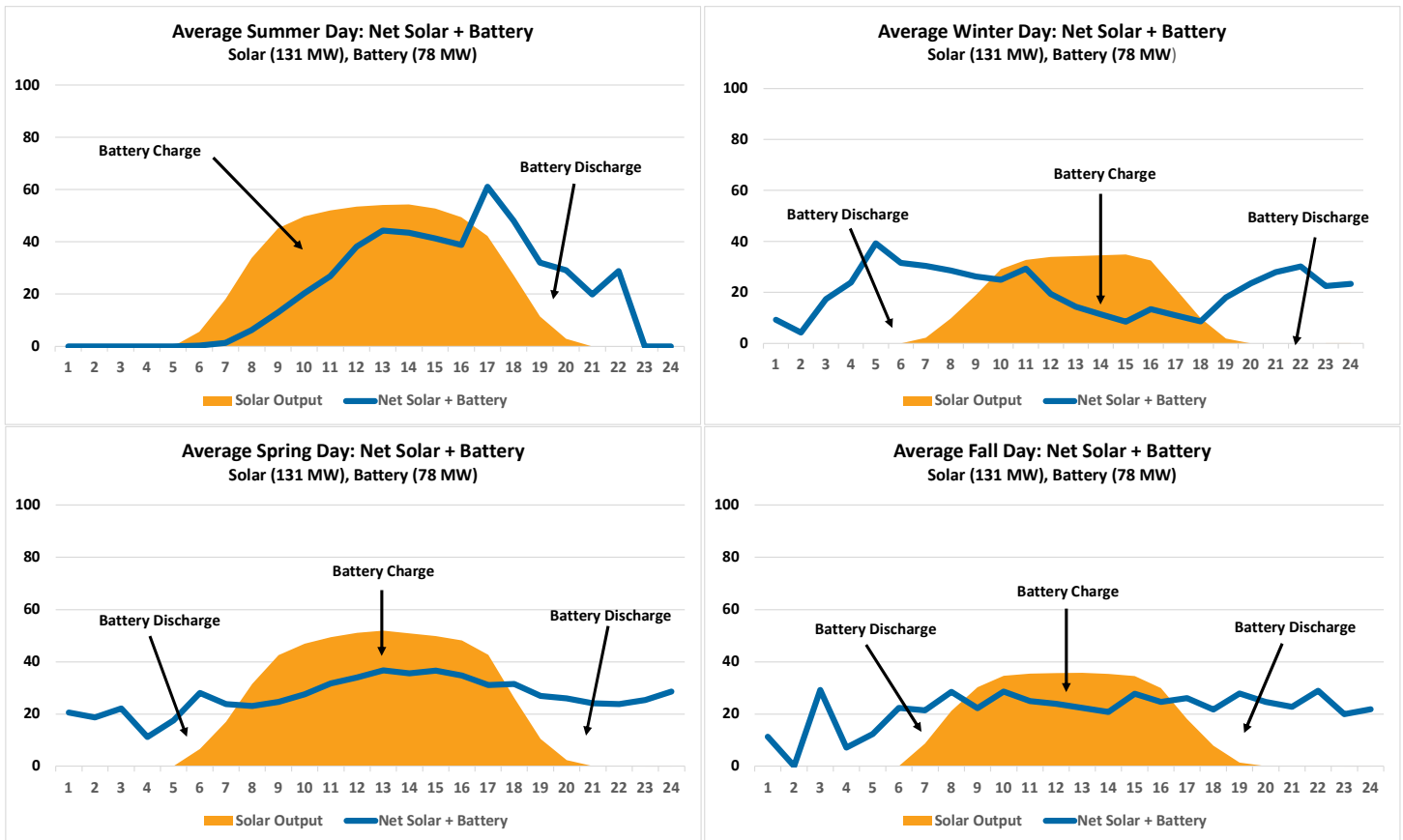


Figure 15.3-9: Solar/Battery Utilization Per Season



Carbon Emissions

An important consideration for the future is the potential additional cost of carbon emissions. While there is no current CO₂ emission cost for KYMEA's resources, a carbon tax, cap-and-trade, mass limit, or rate limit are all CO₂ costs that have previously been proposed by the executive branch through EPA regulations or by the legislative branch through legislation.

Figure 15.3-10 shows a comparison of the CO₂ emission intensity rate of the four long-term plans with the intensity rate of the Obama-era CCP target for Kentucky. CO₂ emission intensity is calculated as pounds of carbon emitted to serve native load divided by the native load megawatt-hours. While the Net Zero plan is carbon neutral on an annual megawatt-hour basis, carbon neutrality is achieved by selling excess wind into the MISO market and counting those megawatt-hours to offset carbon emitting hours. The Net Zero plan relies on carbon emitting MISO market resources to meet energy needs when the wind, solar, and battery resources are not sufficient to meet the native load requirements. The Net Zero plan also relies heavily on the MISO market participants purchasing the KYMEA excess wind generation. There is a danger with this assumption because if too much wind is added across the MISO footprint, it is likely there will not be sufficient load and/or transmission to absorb KYMEA's extra wind. In those circumstances, the wind will be curtailed, which limits the effectiveness of the Net Zero carbon neutrality calculation. As shown in the figure, all four KYMEA long-term plans produce a much lower CO₂ intensity rate than the CCP target.

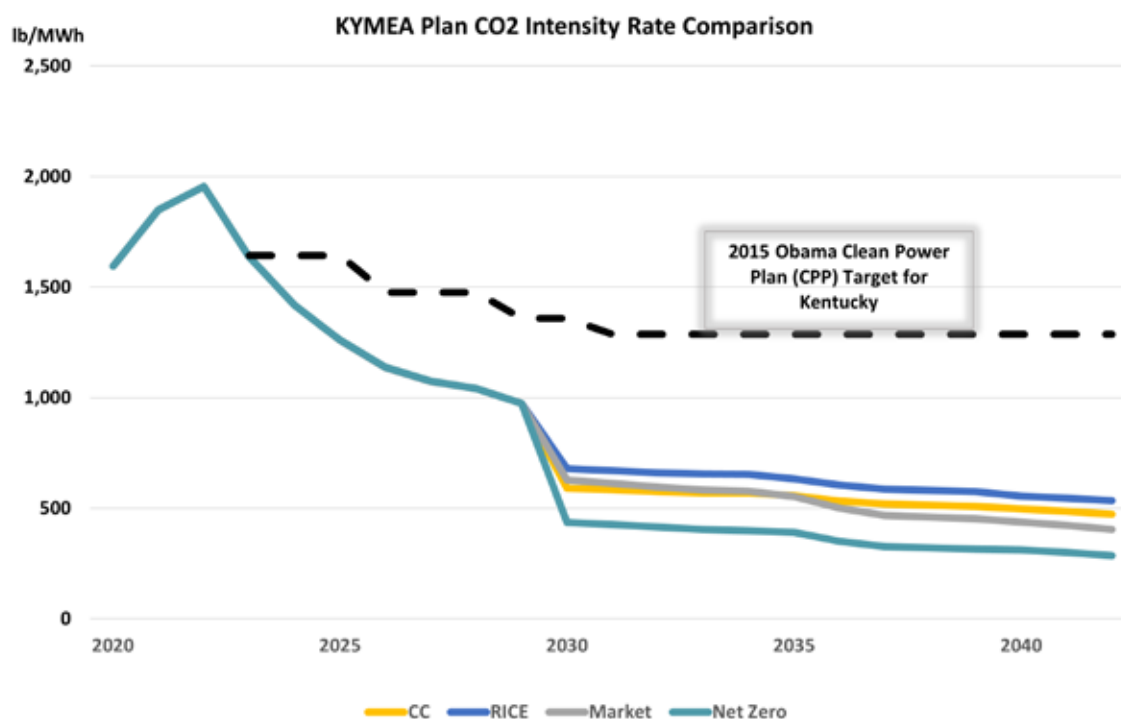


Figure 15.3-10: KYMEA Plan CO₂ Intensity Rate Comparison (lb/MWh)



SO₂ Emissions

The KYMEA sulfur dioxide (SO₂) emissions, which are regulated by the EPA under the Cross-State Air Pollution Rule (CSAPR), are nearly zero by 2037. As illustrated by Figure 15.3-11, there are three significant drops. The first drop occurs in 2022 when the IPMC-Joppa PPA expires. The next significant drop occurs in 2029 when the BREC-Wilson PPA expires. The third significant drop occurs in 2037 when nearly all coal-based generation in the MISO Central subregion from which KYMEA purchases energy has been retired.

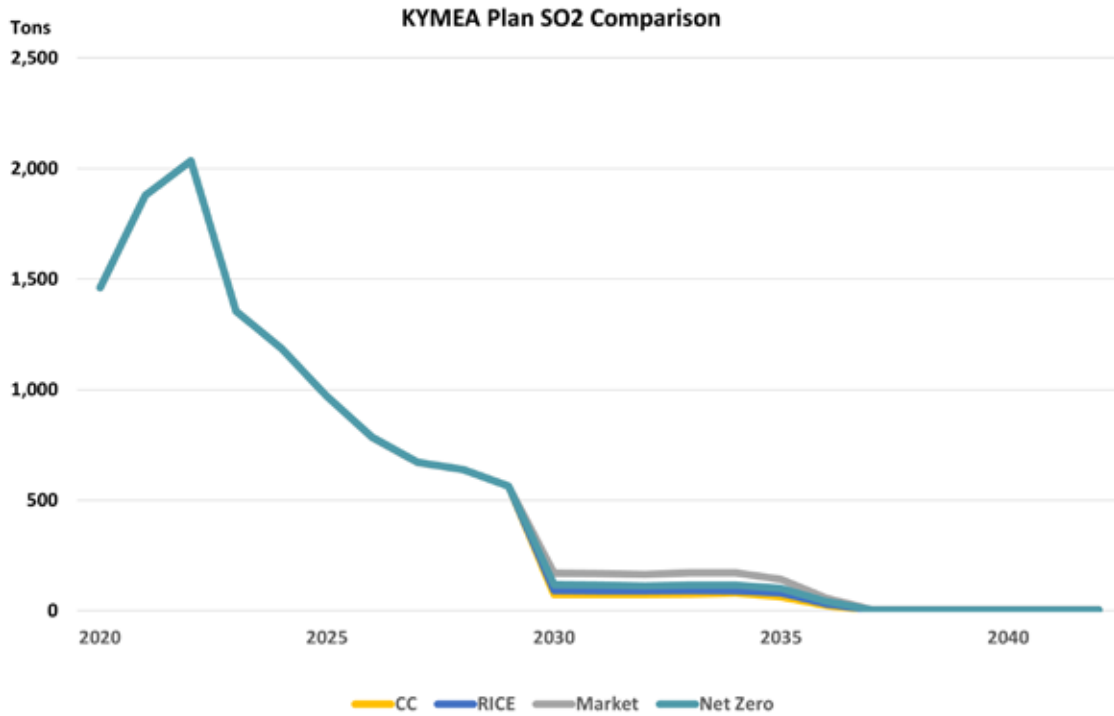


Figure 15.3-11: KYMEA Plan SO₂ Comparison (Tons)



NOx Emissions

The KYMEA nitrogen oxide (NOx) emissions are regulated by the EPA under the Cross-State Air Pollution Rule (CSAPR). As illustrated by Figure 15.3-12, there is a significant drop in 2022 when the IPMC-Joppa PPA expires. In 2029, the RICE Plan has a slight uptick in NOx emissions while the other three plans experience a drop.

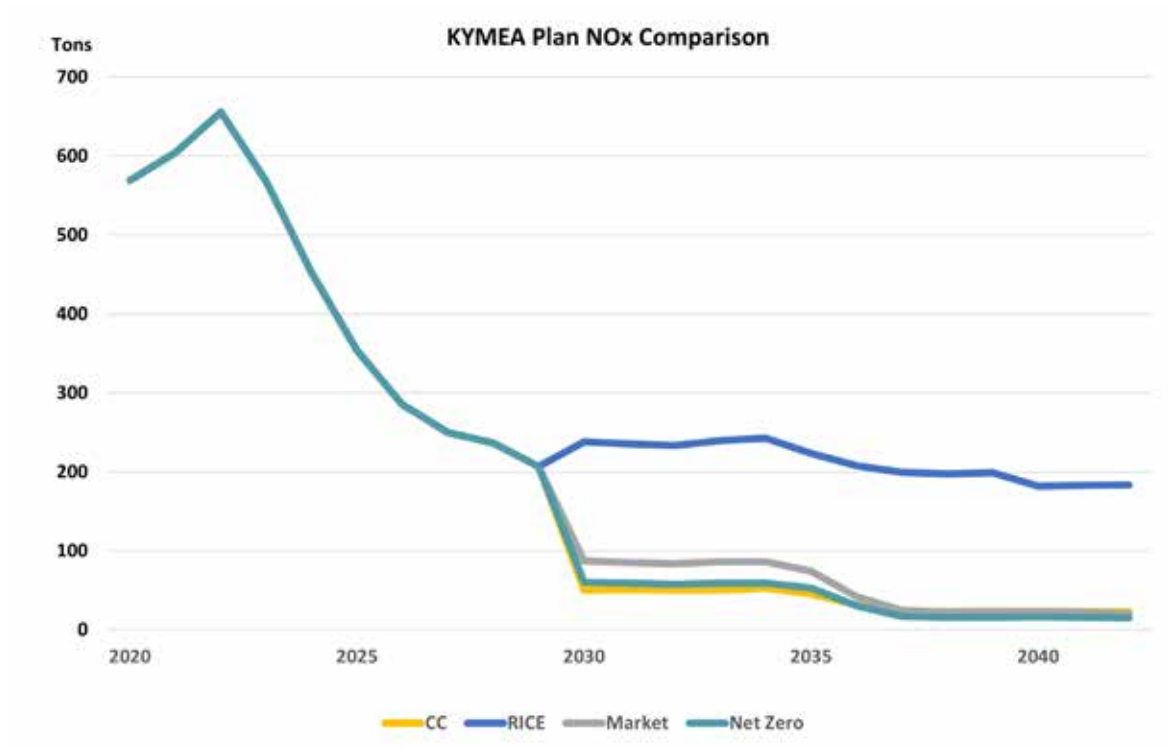
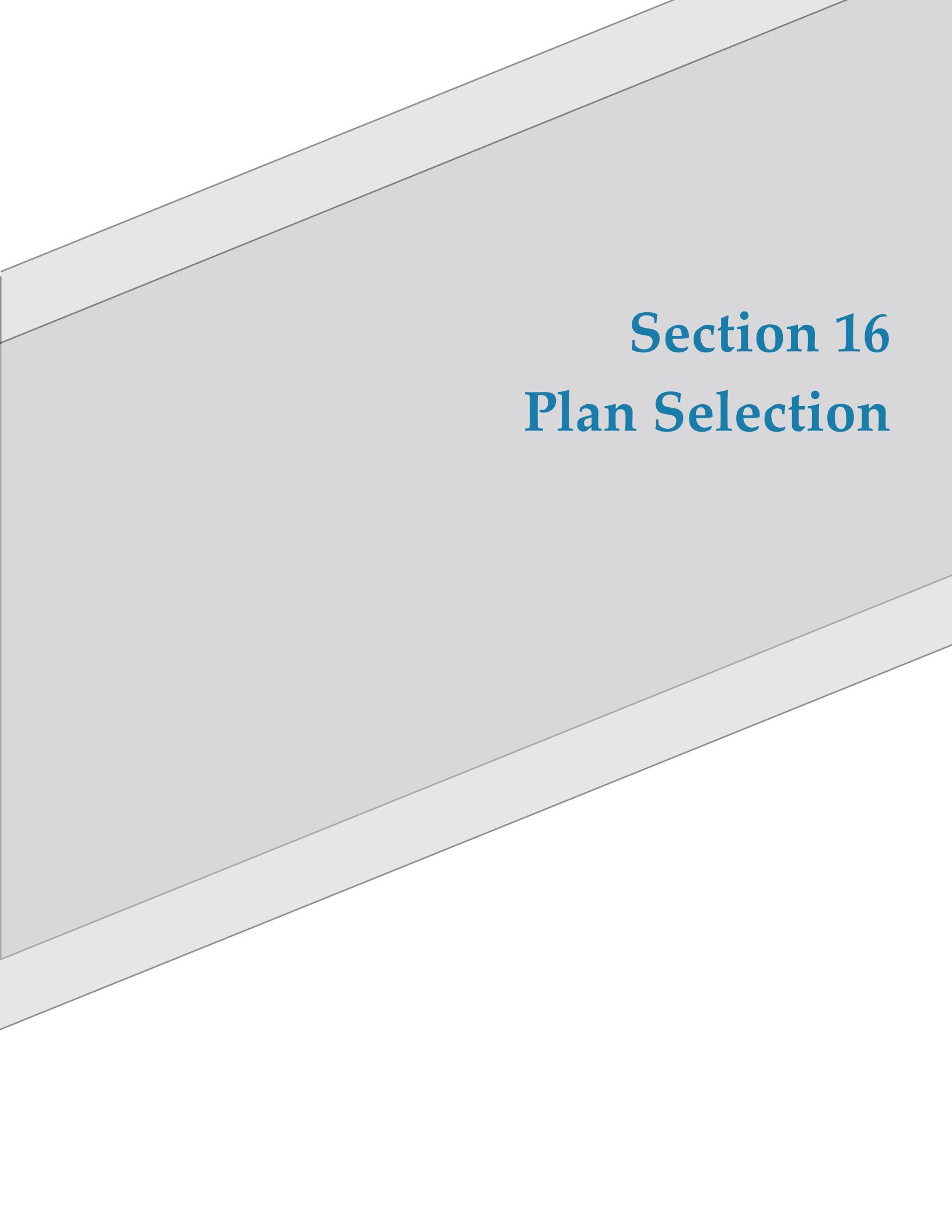


Figure 15.3-12: KYMEA Plan NOx Comparison (Tons)

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Section 16

Plan Selection

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16. PLAN SELECTION

16.1 Selection Approach

The responsibility for selecting an IRP resides with the KYMEA Board of Directors. The Board directed the KYMEA staff to provide in-depth cost and risk analysis from which the Board could make an informed decision with the best information available. The IRP2020 report summarizes the analysis and findings of the Board's directive.

KYMEA's approach is least-regrets planning. Least-regrets planning requires selection of a preferred plan based on sensitivity, stochastic uncertainties, scenarios, and stress test analysis. The selection of a plan is a comprehensive approach to address power supply needs, balancing competitive costs, planning reserves, operational reliability, market risk, flexibility, stability, and robustness.

Future Considerations

For the near-term plan selection, consideration was given for:

- Accommodation of Benham and/or Berea if they would like to join the AR Project.
- Design of a flexible plan which will permit a larger take of the Ashwood Solar I Project.
- Utilization of least-regrets scenario planning



16.2 Preferred Plan Selection - PLAN E

On December 29, 2020, the KYMEA Board of Directors held a special board meeting to select a near-term power supply plan.

AR Project Existing Resources

KYMEA began operations on May 1, 2019. The Agency's initial power supply, chosen by the AR Project members to serve its all-requirements power supply and transmission needs, consists of a mix of purchase power agreements (PPAs) fueled by coal, natural gas, hydroelectric, and diesel generation resources. The PPAs provide great flexibility, allowing the Agency to purchase from the MISO and PJM markets if the market prices are cheaper than the PPA energy cost. KYMEA has a 20-year PPA for 53.75 MW of the Ashwood Solar I Project, which begins operation in late 2022.

Near-Term Decisions

The responses to RFP2020 provided KYMEA with near-term options to consider for the Agency's capacity and energy needs. In addition to selecting one or more suppliers from the RFP, the KYMEA Board also had several other decisions to make before the end of 2020 or shortly thereafter.

Immediate decisions before KYMEA were:

1. **RFP Capacity/Energy Proposals.** Staff evaluated and ranked the RFP options and provided the results for the Board's consideration as described in Section 13 (Plan Development), where the Duke Energy-Indiana (DEI) Intermediate Capacity and Energy proposal was selected as the preferred option for further analysis.
2. **MISO Point-to-Point Transmission Service Reservation (TSR).** Staff recommended for the Board's consideration the appropriate size and term of a MISO (Source) point-to-point firm transmission path to the LG&E/KU balancing area (Sink) coupled with LKE network integrated transmission service (NITS) to ensure power delivery and operating reserves to satisfy a 1-in-10 peak demand forecast. The need for the additional MISO PTP and LKE NITS is dependent upon the RFP selection (Item 1)
3. **Paducah Power System (PPS) Peaking Capacity.** By December 31, 2020, KYMEA could exercise a one-time election to decrease the PPS Peaking Capacity from 90 MW to no less than 30 MW. The election, if exercised, commences on June 1, 2023.
4. **Ashwood Solar I Project.** Ashwood was designed as an 86 MW solar plant, which KYMEA would take 53.75 MW (62.5%) and Owensboro Municipal Utility (OMU) would take 32.25 MW (37.5%). OMU opted not to take their portion, providing KYMEA an opportunity for 32.25 MW of additional solar.

Preferred Plan Selection – PLAN E

To balance cost and risk and provide flexibility, on December 29, 2020, the KYMEA Board of Directors selected PLAN E. The action items of PLAN E are as follows:

1. Reduce the PPS Peaking Capacity to 60 MW beginning June 1, 2023.
2. Negotiate a purchase power agreement for 30 MW of intermediate capacity and energy with Duke Energy-Indiana.
3. Request the necessary LKE and MISO System Impact Studies for 15 MW of MISO point-to-point transmission and LKE network integrated transmission service.
4. Waive KYMEA's right of first refusal (RoFR) for an additional 32.25 MW from the Ashwood Solar I Project.



PLAN E – Spot Market Stress Test

To test the market exposure of PLAN E, Figure 16.2-1 illustrates that a sensitivity analysis was performed with high-base-low natural gas, energy price, and capacity price sensitivities. A “No Market” sensitivity case was also performed where spot purchases and sales were excluded. The purpose of the No Market sensitivity was to provide an upper-end stress test of KYMEA’s unhedged spot market exposure.

The market stress test increases costs \$21MM compared to the Base Market case over the 5-year near-term period. The \$21MM calculated by the stress test can be thought of as the maximum market exposure of PLAN E. While it is unrealistic that there would not be any available spot market purchases or sales, the market stress test provides information regarding the robustness of the plan without reliance on the uncertain spot market.



Figure 16.2-1: PLAN E - Spot Market Stress Test



PLAN E – Operating Reserves Stress Test

Figures 16.2-2 and 16.2-3 illustrate PLAN E’s operating reserves for two seasons (summer and winter), and three sensitivities (Peak Day, 1-in-10 Peak Day, 1-in-10 Peak Day with N-1 Contingency). The N-1 contingency assumes PPS Peaking Capacity is forced out, and the Ashwood solar output is 80% of expected.

PLAN E - Summer Season Operating Reserves

The summer season operating reserves stress test shows KYMEA is unable to serve load in the 1-in-10 peak, N-1 contingency; however, the exposure is small.

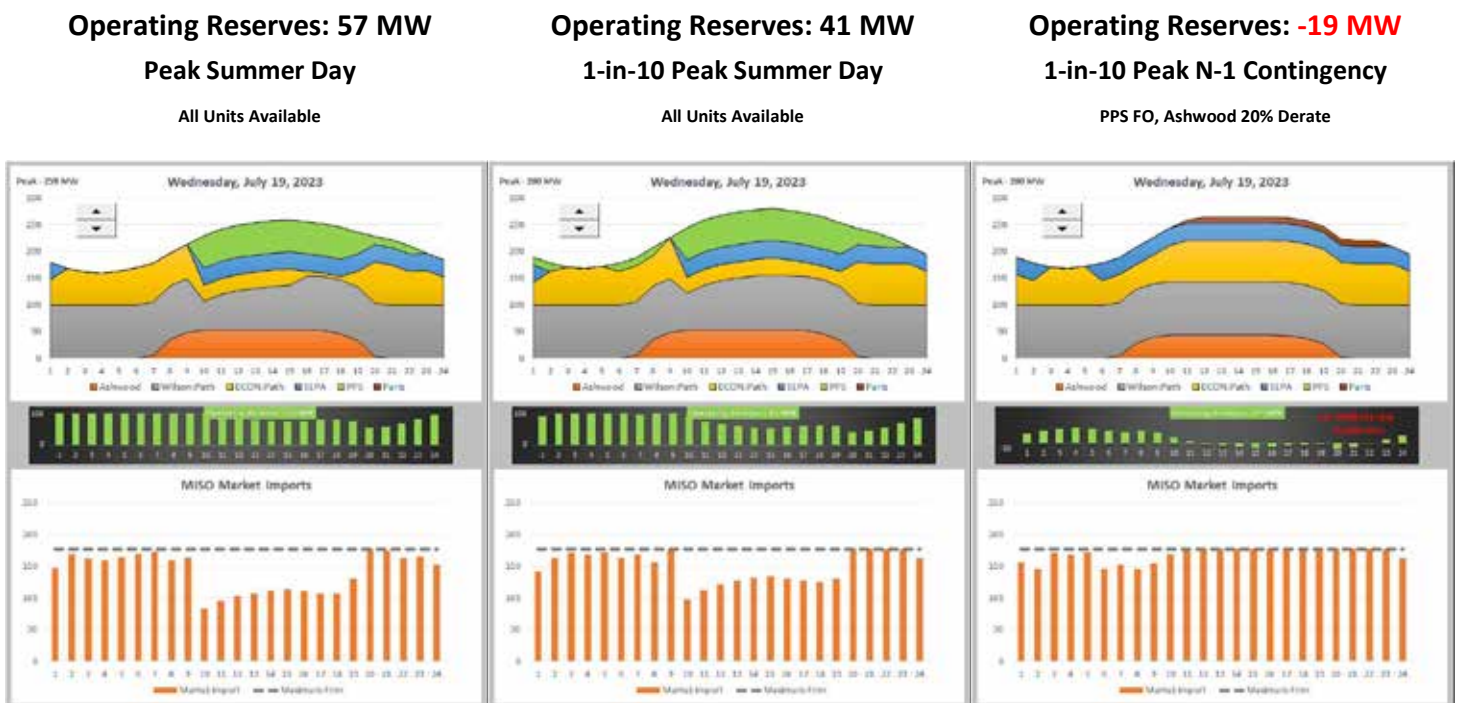


Figure 16.2-2: PLAN E - Summer Season Operating Reserves



PLAN E - Winter Season Operating Reserves

The winter season operating reserves stress test shows KYMEA is unable to serve load in the 1-in-10 peak, N-1 contingency; however, the exposure is small.

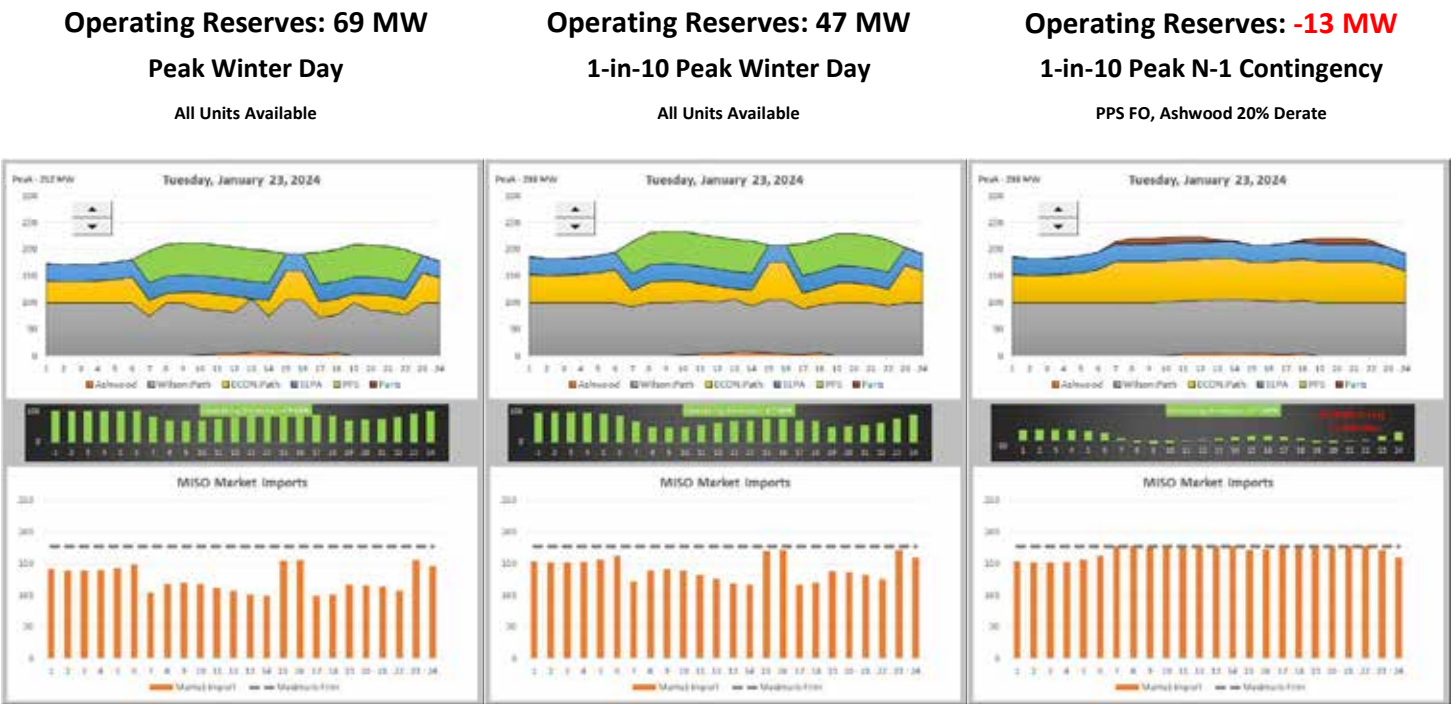


Figure 16.2-3: PLAN E - Winter Season Operating Reserves



16.3 Ashwood Solar I Project Discussion

To address the imbalance concerns associated with adding more solar generation, KYMEA analyzed the expected Ashwood output intermittency.

Ashwood Intermittency Imbalance Concerns

The difficulty associated with integrating Ashwood into KYMEA's portfolio stems from the fact that the LKE transmission system is not in an RTO; therefore, fluctuations in KYMEA's supply and demand balance fall under LG&E/KU's imbalance tariff, which provides a very narrow bandwidth of movement ($\pm 7.5\%$ of hourly demand). This is especially challenging because KYMEA's conventional method for planning the daily balancing operation involves adjustments to its day-ahead, hour-ahead, and real-time operating procedures subject to MISO tags and ramping availability.

Figure 16.3-1 illustrates Ashwood at 53.75 MW and 86 MW. At 53.75 MW, two standard deviations of solar intermittency are as high as 20 MW. At 86 MW, two standard deviations grow to as high as 35 MW.

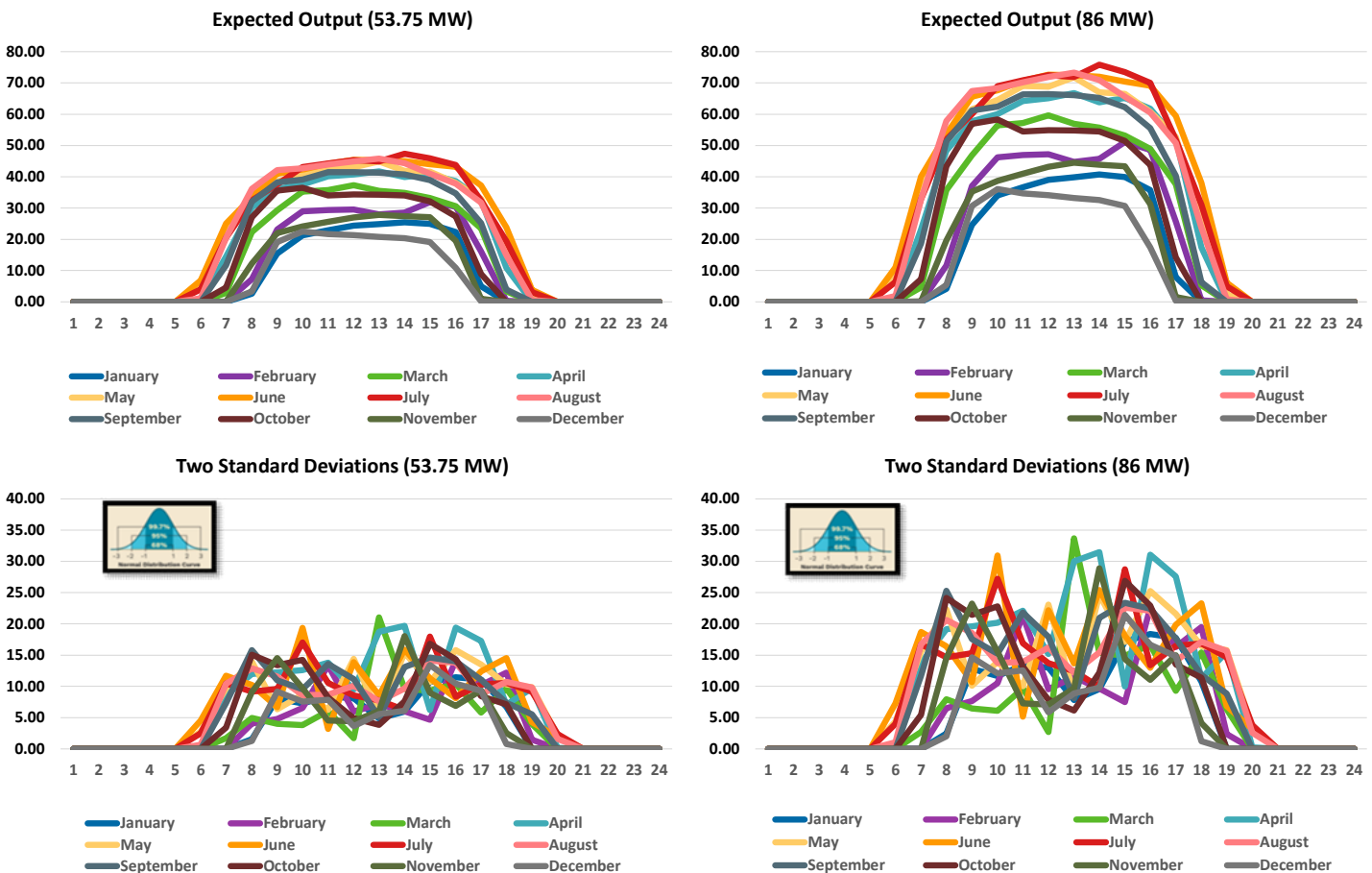


Figure 16.3-1: Ashwood Solar Output and Intermittency



Deferring Ashwood Decision

By choosing PLAN E, the KYMEA Board waived the Agency's right of first refusal (RoFR) for an additional 32.25 MW from the Ashwood Solar I Project. This decision was largely driven by uncertainty regarding imbalance.

If KYMEA can resolve solar intermittency imbalance concerns, and RWE is unsuccessful in remarketing the additional 32.25 MW of Ashwood, then the Agency has one final opportunity to take the additional Ashwood solar generation.



16.4 Preferred Plan Selection - Pivot to PLAN K

The KYMEA Board of Directors may have an opportunity to take the additional 32.25 MW of the Ashwood Solar I Project, increasing the KYMEA renewable energy mix (solar and hydro) to 19%. By increasing the Ashwood solar to 86 MW, the near-term plan pivots from PLAN E to PLAN K.

Addressing Solar Intermittency - Dynamic Schedule Solution

In addition to daily fluctuations caused by sunrise and sunset, the output from solar panels can also change suddenly due to clouds. Variability caused by clouds can make it more difficult for KYMEA to predict how much energy to import from MISO during the next hour of the day. Fast fluctuations in output from solar energy does not only disrupt the hourly load-following, but also the second-to-second balance between total electric supply and demand.

Today, BA grid operators send a signal to power plants approximately every four seconds to ensure the total amount of power injected into the grid consistently equals the total power withdrawn. KYMEA's strategy to overcome solar variability is to mimic how a grid operator balances load; but, instead of sending a signal to a generator, KYMEA will send a signal to MISO in the form of a dynamic schedule.

Dynamic Schedule Definition

From a simple perspective, a dynamic schedule is a means of achieving a time-varying exchange of power where traditional block scheduling is not sufficient. The dynamic schedule is a telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE (automatic generator control/area control error) equation and the integrated value of which is treated as a schedule for interchange accounting purposes.

Ashwood Decision Points and Timeline

The MISO dynamic schedule lessens KYMEA's imbalance concerns, allowing the Agency to consider a greater Ashwood solar share. The Ashwood Solar I Project is scheduled to come online December 1, 2022. KYMEA's committed share is 53.75 MW. Below are the decision points and timeline of events which allows KYMEA to consider an additional 32.25 MW of Ashwood.

- OMU Ashwood Termination: OMU terminated its 32.25 MW share of Ashwood on December 10, 2020.
- KYMEA had the unilateral RoFR to take the additional 32.25 MW to be decided in a 30-day window. RWE (seller) notified KYMEA on January 20, 2021, creating a RoFR window of January 20, 2021, through February 19, 2021.
- The KYMEA Board chose not to exercise its RoFR, giving RWE the right to remarket the 32.25 MW.
- RWE will notify KYMEA regarding the remarketing of the 32.25 MW.
- If the remarketing effort is unsuccessful, KYMEA will decide on taking the additional 32.25 MW.



PLAN E versus PLAN K Comparison

When comparing the PLAN E results to the PLAN K results in Figure 16.4-1, PLAN E is lower cost in the Low Market sensitivity while PLAN K is lower cost in the Base and High Market sensitivities.

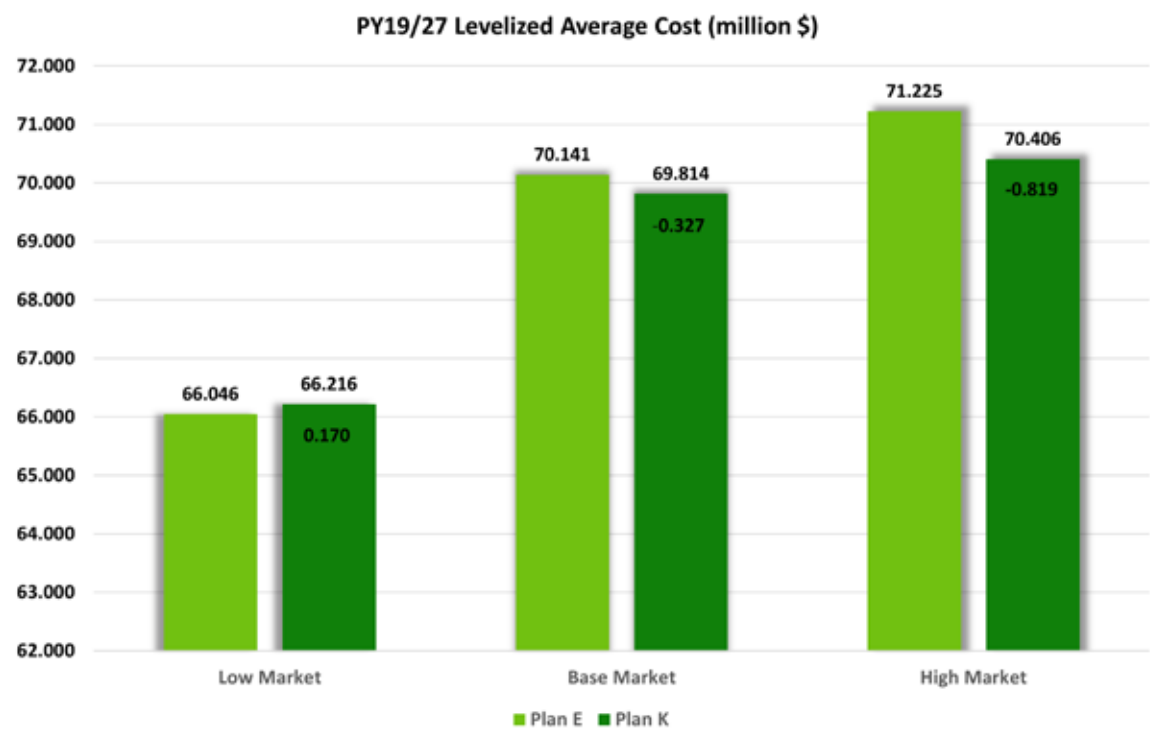


Figure 16.4-1: PLAN E and PLAN K Comparison



PLAN K – Operating Reserves Stress Test

Figures 16.4-2 and 16.4-3 illustrate PLAN K’s operating reserves for two seasons (summer and winter), and three sensitivities (Peak Day, 1-in-10 Peak Day, 1-in-10 Peak Day with N-1 Contingency). The N-1 contingency assumes PPS Peaking Capacity is forced out, and the Ashwood solar output is 80% of expected. The PLAN K results were very similar to the PLAN E results.

PLAN K - Summer Season Operating Reserves

The summer season operating reserves stress test shows KYMEA is unable to serve load in the 1-in-10 peak, N-1 contingency; however, the exposure is small.

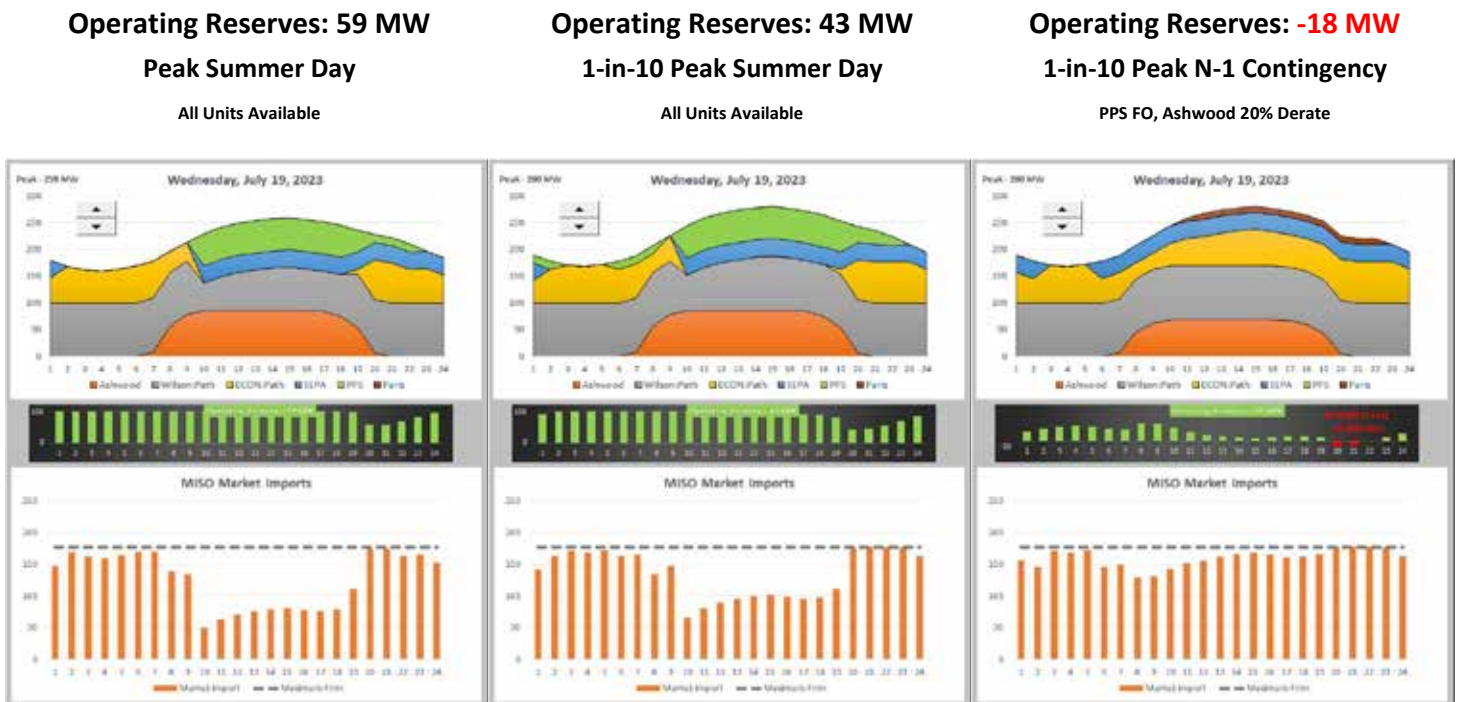


Figure 16.4-2: PLAN K - Summer Season Operating Reserves



PLAN K - Winter Season Operating Reserves

The winter season operating reserves stress test shows KYMEA is unable to serve load in the 1-in-10 peak, N-1 contingency; however, the exposure is small.

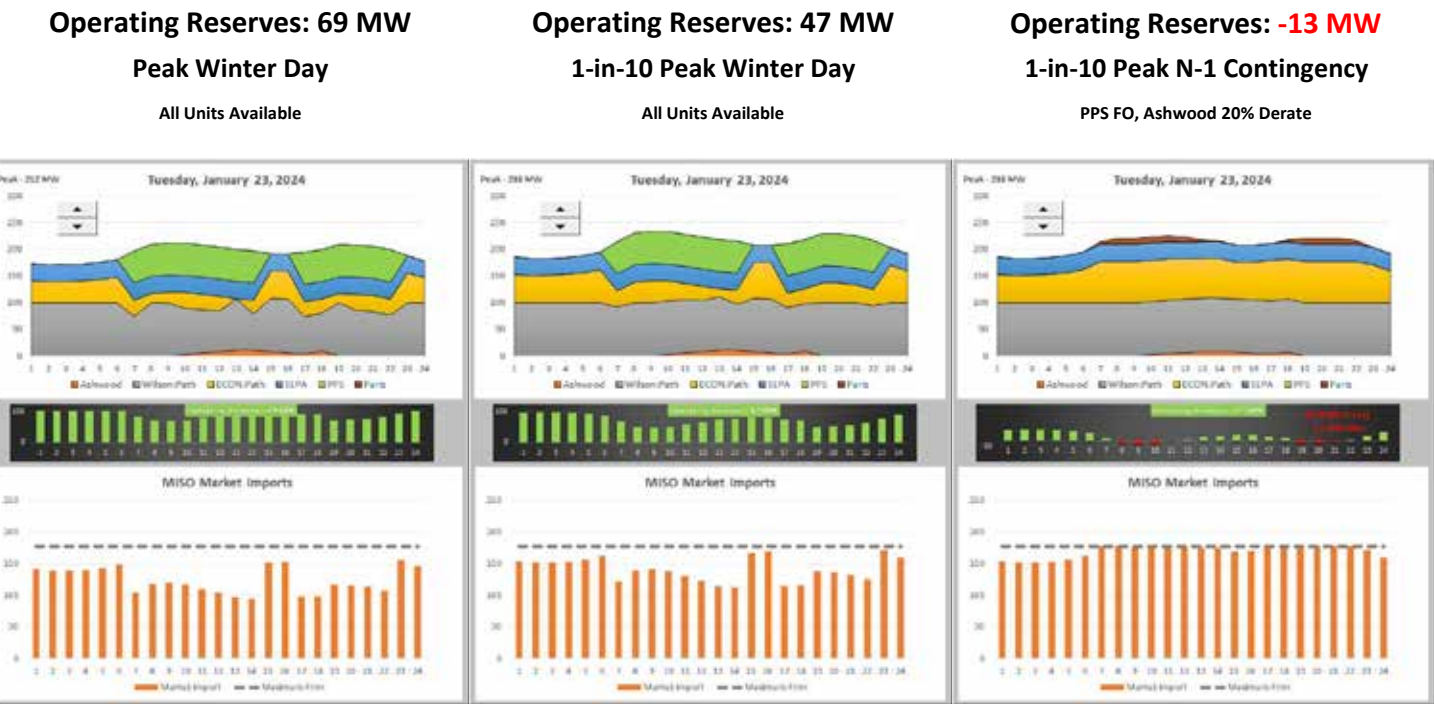


Figure 16.4-3: PLAN K - Winter Season Operating Reserves



As shown in Figure 16.4-4, both PLANs E and K continue to diversify the power supply portfolio being used to serve customers in the members' communities.

Prior to the formation of KYMEA, the members purchased energy from LG&E/KU. The upper left pie chart shows the 2018 LG&E/KU resource mix, which is the last year the members purchased from LG&E/KU. The upper right pie chart illustrates KYMEA's initial portfolio resource mix for the year 2022. The bottom two pie charts illustrate KYMEA's 2025 resource mix for PLANs E and K.

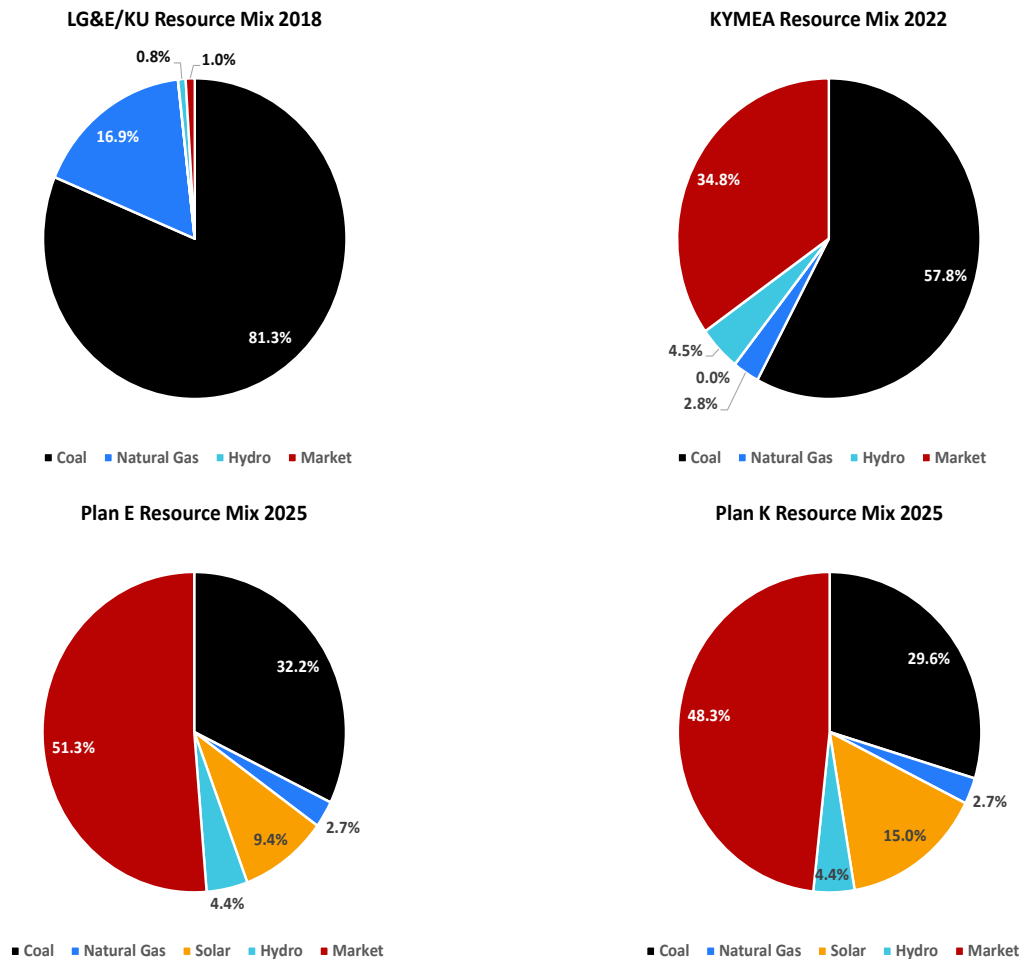


Figure 16.4-4: Mix of Energy Resources to Serve KYMEA Load



Figure 16.4-5 shows the carbon intensity projection for both PLANs E and K. Carbon intensity is calculated as pounds of carbon emitted to serve KYMEA's native load divided by the native load megawatt-hours. As points of reference, a steam-coal plant has a carbon intensity of 2,200 lb/MWh, while a natural gas combined cycle plant has a carbon intensity of 740 lb/MWh. Nuclear, hydro, solar, and wind resources do not emit carbon.

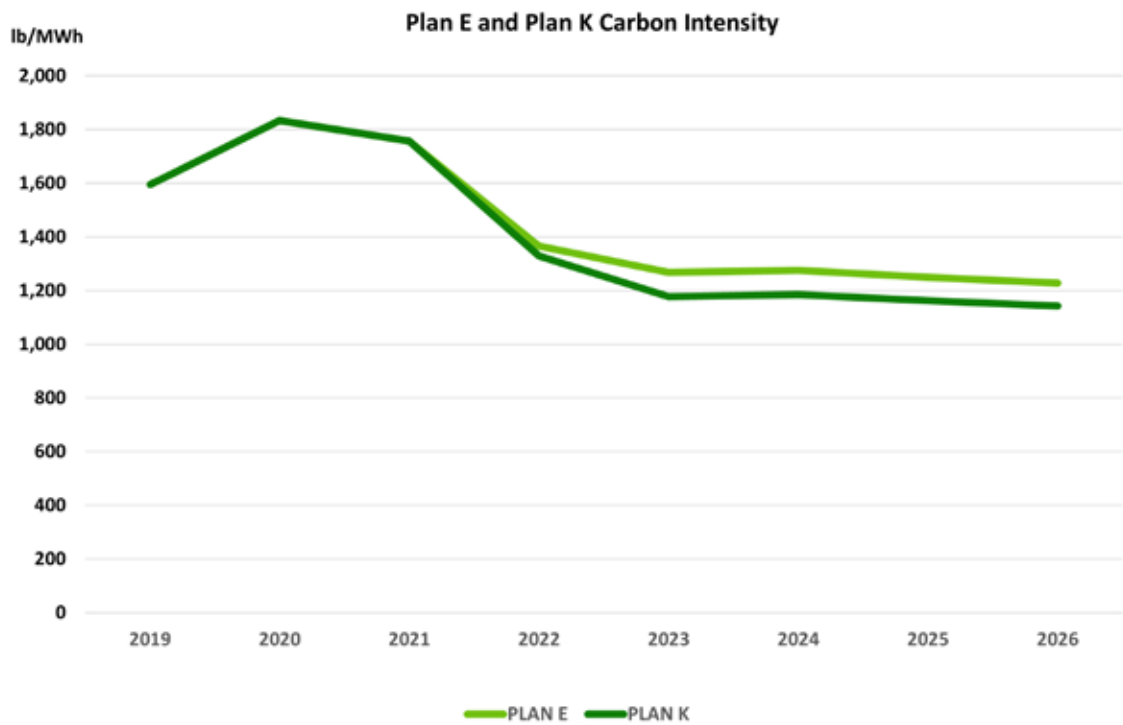
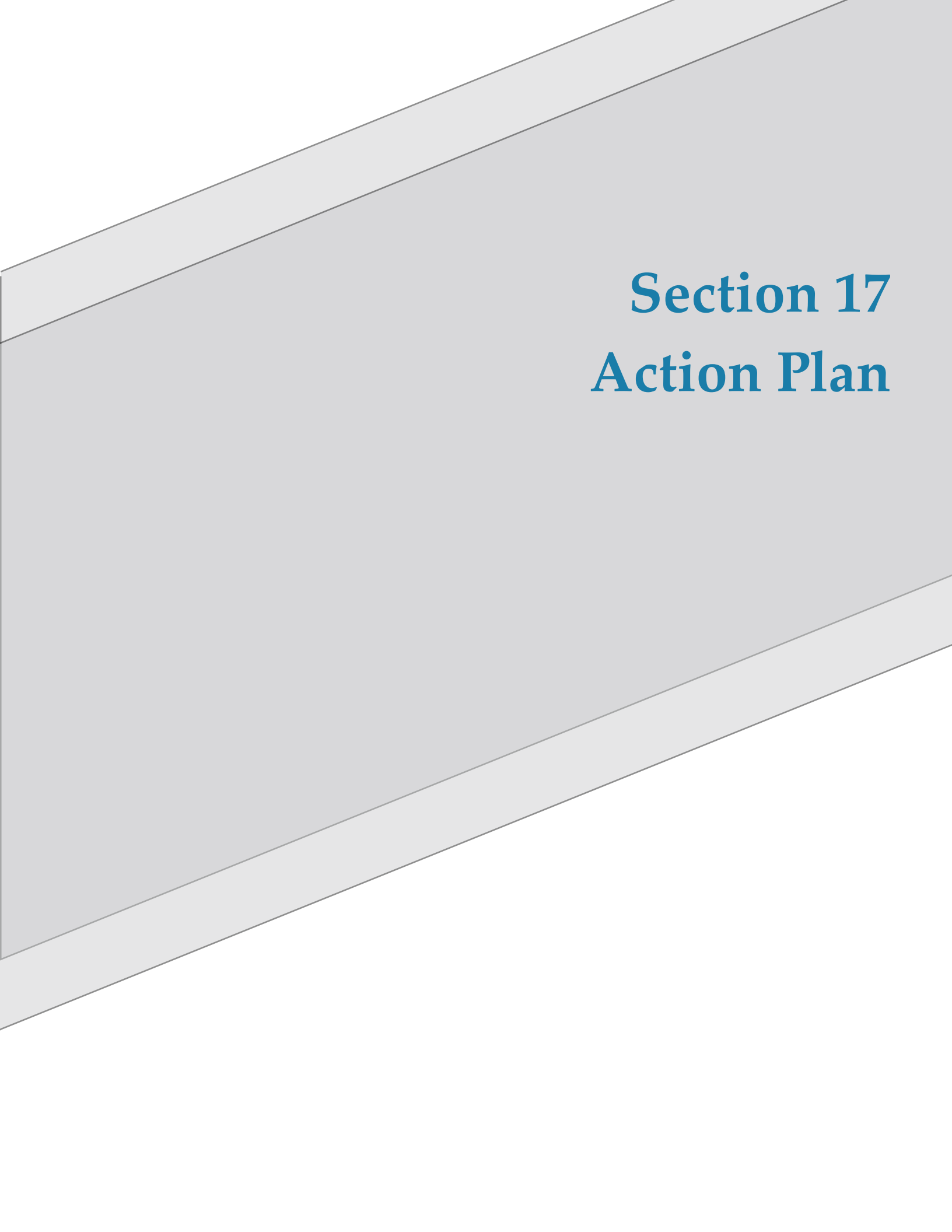


Figure 16.4-5: PLAN E and PLAN K Carbon Intensity

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Section 17 Action Plan

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17. ACTION PLAN

17.1 Near-Term Power Supply Action Plan

As discussed in Section 16 (Plan Selection), KYMEA concluded through least-regrets planning that PLAN E represented a balance of low cost, low risk, and flexibility to meet the members' near-term resource needs. The Near-Term Action Plan outlines the specific activities to implement PLAN E. As with other components of IRP2020, the Near-Term Action Plan is based on the best information available using forecasts generated at the time of this writing. Actual activities to implement the plan are dependent on conditions prevalent at the time of their undertaking, including compliance with current regulatory rules and orders, and may differ from what is contained herein.

Near-Term Plan Implementation

Reduce PPS Peaking Capacity

Action Required

- Reduce Peaking Capacity from 90 MW to 60 MW beginning June 1, 2023.
- Size: 60 MW
- Term: 6/1/2023 – 5/31/2029

Status: Completed December 29, 2020

MISO Point-to-Point Transmission/LKE NITS

Action Required

- Size: 15 MW
- Term: 6/1/2022 – 5/31/2027 (5-years with rollover rights)
- Product: MISO (point-to-point) to LKE (network integrated) Firm Transmission Service

Status: LKE request confirmed* March 24, 2021. MISO request confirmed May 10, 2021.

** As of the writing of this report, LKE NITS was not available for June and July of 2022.*

DEI Capacity and Energy PPA

Action Required

- Size: 30 MW
- Term: 6/1/2022 – 5/31/2027
- Product: Dispatchable capacity and energy

Status: PPA signed July 28, 2021



RWE Ashwood Solar I Project

Action Required

- Size: 54 MW
- Term: 12/1/2022 – 11/30/2042
- Product: Solar capacity and energy
- Monitor construction progress to ensure on-time completion.
- Host groundbreaking ceremony
- Host ribbon cutting ceremony.

Status: Anticipated on-line date of December 2022

Dynamic Schedule

Action Required

- Size: Up to 100 MW
- Product: Dynamic schedule as a means of achieving a time-varying exchange of power with MISO to balance KYMEA supply and demand inside the LKE transmission system
- Tasks: Hardware, Software, ICCP, Counterparty Agreements

Status: Anticipated completion by 1st quarter of 2022

Enterprise Risk Management

Action Required

- Task: Update KYMEA's hedge plan and position report to reflect the changing portfolio
- Reporting: Internal Risk Committee (IRC), Board Risk Oversight Committee (BROC), and Board of Directors

Status: On-going process

Benham and Berea – AR Project Decision

Action Required

- Status: Benham and Berea, who are currently transmission-only members, participated in IRP2020.
- Task: Provide information to both communities so they can make an informed decision regarding participation in the AR Project in 2024 after their current wholesale PPAs expire.

Status: On-going process



17.2 Long-Term Action Plan

Long-Term Power Supply Action Plan

KYMEA developed and analyzed 4 long-term power supply plans combined with nine scenarios as part of IRP2020. The Agency also analyzed two complete carbon-free plans, which included storage and did not rely on fossil generation. No action is required for the long-term power supply plans. KYMEA's long-term focus is on the next tranche of resource and transmission needs beginning in 2027, with an additional need in 2029. The Agency's next IRP, which will likely be published in 2024, will continue addressing those needs.

In addition to long-term power supply and transmission planning, KYMEA is also investigating the following long-term action items.

Southeast Energy Exchange Market (SEEM)

SEEM is an automated platform that connects energy buyers and sellers to achieve cost savings by facilitating efficient bilateral intra-hour energy transactions utilizing available (unsubscribed) transmission capability. The platform is not an RTO, nor does it replace the bilateral market or existing agreements; but it is an enhancement to the bilateral market. Existing BA and transmission service provider requirements are not affected or changed through a SEEM membership. As illustrated in Figure 17.2-1, SEEM's proposed initial membership includes 17 entities in the southeastern United States. The group currently represents over 160,000 MWs of capacity and 32 million retail customers.¹¹⁹

SEEM Footprint > 160,000 MW Generating Capacity

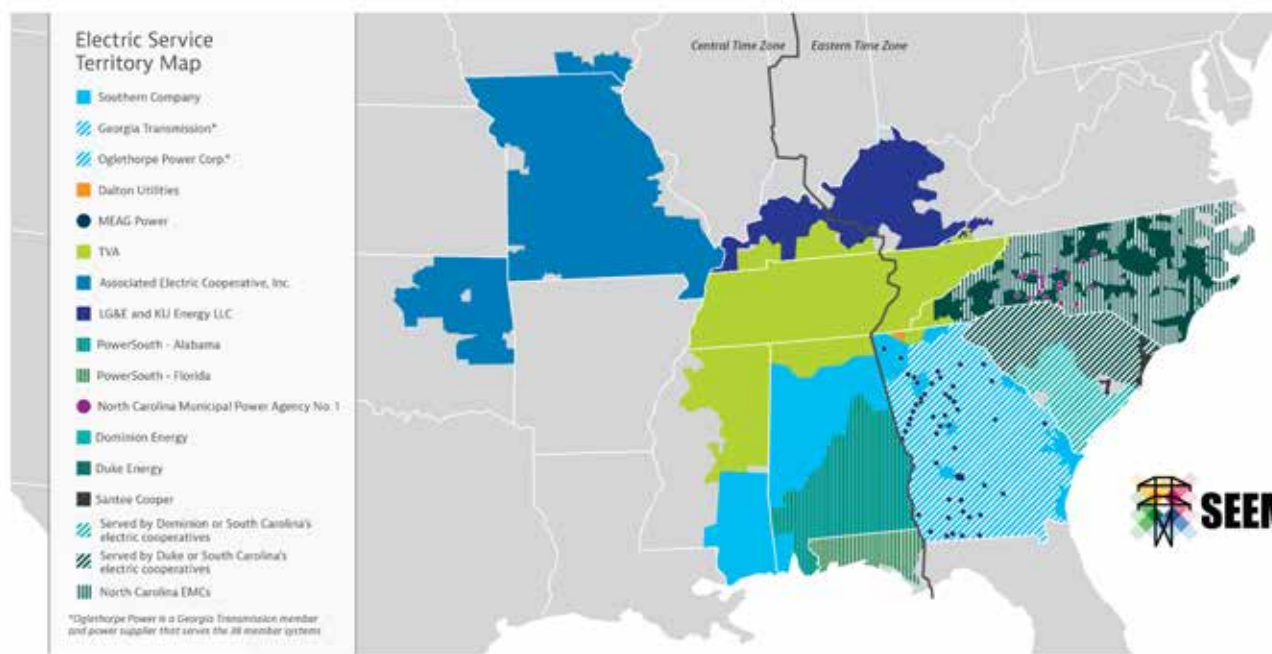


Figure 17.2-1: SEEM Footprint

119

Southeast energy exchange market. (n.d.). Retrieved May 07, 2021, from <https://southeastenergymarket.com/>



SEEM Benefits

- Low cost and low risk opportunities to provide a shared market structure.
- Access to a 15-minute energy exchange market.
- Potential for cost savings.

Power Conservation Alert (PCA) Program

The Power Conservation Alert (PCA) Program is to notify customers of KYMEA's request for voluntary power conservation measures. The PCA would alert KYMEA member customers prior to an emergency event to avert a potential involuntary brownout or blackout situation similar to the results of the polar vortex in Texas in February 2021. The program would allow KYMEA to declare a PCA and automatically notify members and their voluntary customers (e-mail and/or text) that a conservation event has occurred to which the customer may voluntarily respond to conserve energy.

Power Green Kentucky™

Power Green Kentucky gives members' retail customers the option to request up to 100% green energy. The green energy is sourced from the Ashwood Solar I Project and SEPA Hydro. When a member's customer participates in the program, KYMEA allocates that portion of its renewable portfolio to the customer who purchased the Green Power. KYMEA charges the member for the green power; and the member, in turn, charges the retail customer.

KYMEA creates a non-fungible KYMEA Green Tag, which self-certifies that the energy was generated from an eligible carbon-free energy resource (renewable electricity) and was fed into the KYMEA shared system of power lines that transport energy.

Drive Green Kentucky™

Drive Green Kentucky is a program to support and encourage the advancement of electric vehicle (EV) use in our member communities. KYMEA's partnership with members, businesses, community leaders, and automakers will contribute to a reduction in emissions, make Kentucky's roads EV friendly, and bring additional revenue to local communities.

Drive Green Kentucky Objectives

1. Consumer Education
 - Develop education materials regarding the benefits of electric vehicles.
 - Publish a website with fact sheets outlining the cost, range, maintenance, and emissions of EVs.
 - Provide an interactive map of EV charging stations in Kentucky and a link to compare cars in today's market.
2. Assist in Expanding EV Participation
 - Organize all-electric ride and drive events in member communities.
 - Convert the KYMEA fleet to electric once long distance EV capability and charging are readily available.
 - Partner with automakers, and fleet owners to bring EVs to member communities.



3. Increase Availability of Charging Stations

- Provide communities and businesses with EV resources and lists of qualified Level 2 and DCFC charging station equipment to purchase from.
- Encourage, support, and assist in financing EV infrastructure to member communities.

4. Recognize participating communities as leaders in the Commonwealth, paving the way for the electrification of transportation in Kentucky.

The map in Figure 17.2-2 illustrates a proposed Electric Highway Coalition that spans the southeast. KYMEA will keep abreast of developments and opportunities in the electric charging station network for its member communities.



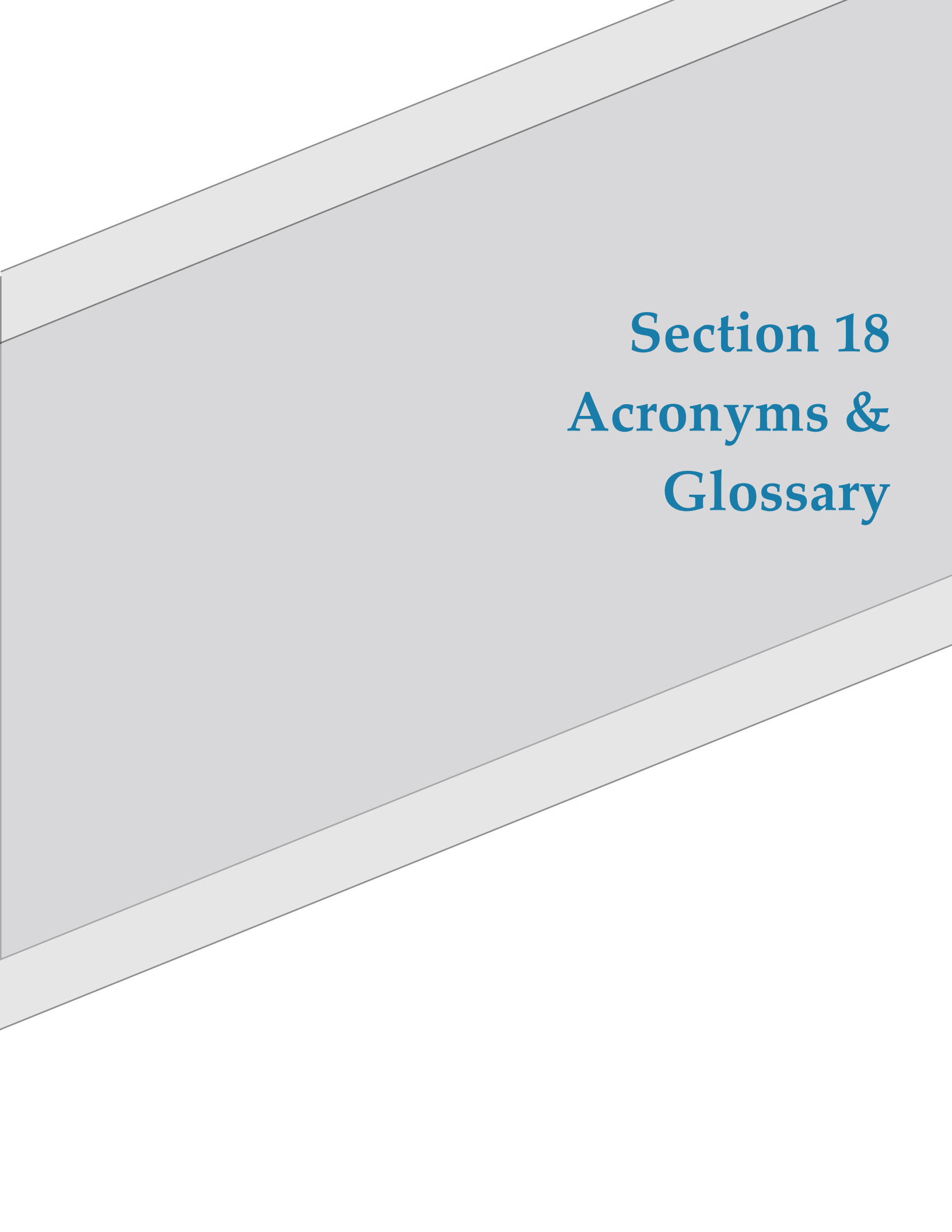
Figure 17.2-2: Proposed Southeast Electric Highway Coalition¹²⁰

120 Lewis, M. (2021). The Electric Highway Coalition. Six US utilities form Electric Highway Coalition in Southeast, Midwest. Electrek. <https://electrek.co/2021/03/02/six-us-utilities-form-electric-highway-coalition-in-southeast-midwest/>.



Battery Demonstration Project

Generally, grid-scale batteries are either paired with a generating resource, such as a solar facility, or placed on the transmission and distribution system, such as at substations, to help balance local electric supply and demand. Utilizing batteries for grid-scale operation potentially provides benefits for KYMEA, but there is much to learn before making this type of investment. As part of the long-term action plan, KYMEA will investigate opportunities for battery demonstration projects paired with the Ashwood Solar I facility or at member locations.

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Section 18 Acronyms & Glossary

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18. ACRONYMS & GLOSSARY

18.1 Acronyms

AC	Air Conditioner
ACI	Activated Carbon Injection
ADMS	Advanced Distribution Management System
AEO	Annual Energy Outlook
AF	Acre-Feet
AFB	Air Force Base
AFUDC	Allowance for Funds Used During Construction
AMA	Active Management Area
AMI	Advanced Metering Infrastructure
APP	Aquifer Protection Permit
BA	Balancing Authority
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BCF	Billion Cubic Feet
BESS	Battery Energy Storage System
BNEF	Bloomberg New Energy Finance
BTA	Biennial Transmission Assessment
Btu	British Thermal Unit
CAA	Clean Air Act
CAES	Compressed Air Energy Storage
CAFO	Concentrating Animal Feeding Operation
CAIDI	Customer Average Interruption Duration Index
CC	Combined Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture & Sequestration
CDA	Conditional Demand Analysis
CEC	Certificate of Environmental Compatibility
CFI	Communicating Fault Indicators
CFL	Compact Fluorescent Lamp
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
CPP	Clean Power Plan

CPP-RES	Critical Peak Pricing for Residential Customers
CRA	Congressional Review Act
CSP	Concentrating Solar Power
CT	Combustion Turbine
CWA	Clean Water Act
DA	Distribution Automation
DAM	Distribution Asset Monitoring
DE	Distributed Energy
DER	Distributed Energy Resources
DG	Distributed Generation
DMS	Distribution Management System
DR	Demand Response
DRESLM	Demand Response, Energy Storage and Load Management Program
DSCADA	Distribution Supervisory Control and Data Acquisition
DSM	Demand Side Management
EE	Energy Efficiency
EES	Energy Efficiency Standard
EGU	Electric Generating Units
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIS	Environmental Impact Statement
ELCC	Effective Load Carrying Capacity
ELG	Effluent Limitations Guidelines
ELMP	Extended Locational Marginal Price
EMS	Energy Management System
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPRI	Electric Power Research Institute
ESA	Endangered Species Act
ESS	Energy Storage System
ECT-1R	Combined Advantage (9 am – 9 pm)
ECT-2	Combined Advantage (Noon – 7 pm)
ERCOT	Electricity Reliability Council of Texas
ET-1	Time Advantage (9 am – 9 pm)



ET-2	Time Advantage (Noon – 7 pm)
ET-EV	Experimental Electric Vehicle Charging Rate Schedule
ET-SP	Time Advantage Super Peak
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FGD	Flue Gas Desulfurization
FM	Fire Mitigation
FONSI	Finding of No Significant Impact
GHG	Greenhouse Gas
GUAC	Groundwater Users Advisory Council
GWh	Gigawatt-Hours
HAPS	Hazardous Air Pollutants
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
IVVC	Integrated Volt/VAR Control
KRS	Kentucky Revised Statutes
kW	Kilowatt
kWh	Kilowatt-Hour
LAER	Lowest Achievable Emission Rate
LED	Light-emitting Diode
LG&E/KU	Louisville Gas & Electric/Kentucky Utilities
LKE	Louisville Gas & Electric/Kentucky Transmission Area
Li-on	Lithium-ion
LNB	Low NOx Burners
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MCP	Market Clearing Price

MER	Measurement and Evaluation Research
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-Hour
NAAQS	National Ambient Air Quality Standards
NaS	Sodium-sulfur
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NNSR	Nonattainment New Source Review
NOx	Nitrogen Oxide
NP	Network Protector
NPDES	National Pollution Discharge Elimination System
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operation & Maintenance
OMS	Outage Management System
ORDC	Operating Reserve Demand Curve
PAC	Program Administrator Costs Test
PC	Participant Cost Test
PCB	Polychlorinated Biphenyls
PM	Particulate Matter
PMUs	Phasor Measurement Units
PPA	Purchased Power Agreement
PPH	People Per Household
PRMR	Planning Reserve Margin Requirement
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PTR	Peak Time Rebate
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PWR	Pressurized Water Reactors
RCRA	Resource Conservation & Recovery Act
RE	Renewable Energy



RES	Renewable Energy Standard
RFP	Request for Proposal
RICE	Reciprocating Internal Combustion Engine
RIM	Rate Impact Measure Test
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard
SAT	Single Axis Tracking
SCED	Security Constrained Economic Dispatch
SCR	Selective Catalytic Reduction
SC or SCT	Societal Benefit-Cost Test
SEEM	Southwest Energy Exchange Market
SHM	Substation Health Monitoring
SIP	State Implementation Plan
SIS	Solar Innovation Study
SMR	Small Modular Reactors
SO ₂	Sulfur Dioxide
SPP	Solar Partner Program
T&D	Transmission and Distribution
TRC or TRCT	Total Resource Cost Test
TOU	Time of Use
TWh	Terawatt Hour
USBR	United States Bureau of Reclamation
VAR	Volt-Ampere Reactive
VOC	Volatile Organic Compounds
VOLL	Value of Lost Load
WIIN	Water Infrastructure Improvements for the Nation
ZLD	Zero liquid discharge
Zn-Air	Zinc-Air



18.2 Glossary

Resource Plan (or 2020 Integrated Resource Plan or IRP2020)	Represents the documented process KYMEA undertakes to select an energy resource portfolio for the 2022-2027 period based upon a wide range of supply- and demand-side options.
Acre-Foot	The volume of water that will cover an area of one acre to a depth of one foot. One acre foot equals approximately 325,851 gallons.
Action Plan	Material actions anticipated to occur during the Action Plan Period.
Action Plan Period	For the purposes of this IRP, the timeframe of 2020-2027.
Activated Carbon Injection	An engineered mercury control system from which powdered activated carbon (PAC) is pneumatically injected from a storage silo into the flue gas ductwork of a coal-fired power plant or industrial boiler. The PAC adsorbs the vaporized mercury from the flue gas and is then collected with the fly ash in the facility's particulate collection device.
Ancillary Services	The services necessary to support the transmission of electric power from generators to consumers given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.
Auxiliary Load	The load that serves the power plant itself. Under normal circumstances, the auxiliary load is served by the production at the plant. If the plant is not producing power, then it is necessary for the grid to serve the auxiliary load.
Availability	The ability of transmission and energy resources to meet requirements at all hours.
Baghouse	An air pollution abatement device that traps particulates (dust) by forcing gas streams through large filter bags, usually made of fiberglass or other synthetic fabrics and coatings.
Balancing	The requirement imposed by electricity grids or natural gas pipelines that supply and demand be equal over a certain time period.
Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.
Baseline	In electric markets, refers to an agreed-upon level of electricity consumption from which deviations are measured. Usually based on a customer's historical usage. Variations may be billed at a different rates.
Baseload Plant	An electric generating plant devoted to the production of electricity on a relatively continuous basis. Baseload plants are typically operated for the majority of the hours during a given year and are taken off-line relatively infrequently. Baseload plants usually have a low variable production cost relative to other production facilities available to the system.
Baseload Unit	An electric power plant, or generating unit within a power plant, that is normally operated continuously to meet the base load of a utility.
Basis	The price difference between otherwise identical products in different markets (in this report, different geographical natural gas markets).
Basis Swaps	Exchange of fixed price for a floating for a defined basis product (e.g., a Houston Ship Channel – HSC Swap at \$1.00 means that one party is willing to pay a fixed price of \$1.00 for the basis while the counterparty is willing to take on the risk of paying the floating price, usually a published index price after the applicable market venue forms the price).



Best Available Retrofit Technology (BART)	Under the Clean Air Act, states must require the installation of the best retrofit emission controls available as part of state strategies for meeting the regional haze rule. The BART requirement applies to facilities built between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollution.
Bilateral Transaction	A direct contract between a seller and buyer outside of a centralized market or exchange (e.g., Nymex or an RTO/ISO). In energy markets, the buyer or seller usually finds his or her matching counter-party through a broker (e.g., voice brokers, ICE, etc.).
Binding Constraint	A constraint is considered binding if changing its limit can result in changing the optimal solution.
Biogas	Otherwise known as biomass gas, a medium Btu gas containing methane and carbon dioxide, resulting from the action of microorganisms on organic materials such as a landfill.
Biomass	Organic non-fossil material of biological origin constituting a renewable energy source that can be either processed into synthetic fuels or burned directly to produce steam or electricity.
British Thermal Unit (Btu)	Used to describe the heat content of fuel. The price of fuel is typically expressed in terms of dollars per million Btu (or \$/MMBtu).
Bus	A conductor or group of conductors that serves as a common connection for two or more electric circuits within a station.
Cap-and-Trade	An approach used to control emissions by providing economic incentives for achieving reductions. A central authority (usually a government or international body) sets a limit or cap on the amount that can be emitted. Companies or other groups are issued emission permits and are required to hold an equivalent number of allowances (or credits), which represent the right to emit a specific amount. The total amount of allowances cannot exceed the cap, limiting total emissions to that level. Companies that need to increase their emission allowances must buy credits from those that emit less. The transfer of allowances is referred to as a trade. In effect, the buyer is paying a charge for emitting, while the seller is being rewarded for having reduced emissions by more than was required.
Capacity	The maximum amount of electricity a generation source can produce in any given moment. Capacity is usually measured in units of megawatts. It should be noted that most generation sources are not operated at their maximum capacity rating during all hours that they are generating electricity. See Capacity Factor.
Capacity Factor	A value used to express the average production level of a generating unit over a given period of time. Capacity factor is expressed as a percentage of the maximum possible production. If the generating unit had operated at its maximum capacity rating for all hours during the period. For example, a generating facility that operates at an average of 60% of its maximum capacity over a measured period has a capacity factor of 60% for that period.
Capacity Margin	The amount of capacity above planned peak system demand available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen demand.
Capacity Markets	Ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand one year in the future.



Capacity Value	A resource's ability to reliably serve load during the top 90 load hours of the year. Capacity value is calculated by dividing the average net capacity of the resource during the top 90 load hours by the resource's maximum hourly capacity.
Carbon Capture and Sequestration (CCS)	A technology under development to limit emissions of carbon by capturing and storing it away from the atmosphere.
Carbon Dioxide (CO ₂)	A naturally occurring gas, and also a by-product of burning fossil fuels and biomass, as well as land-use changes and other industrial processes. It is the principal greenhouse gas that affects the Earth's radiative balance.
Carbon Monoxide (CO)	A colorless, odorless, toxic gas produced by the incomplete combustion of carbon-containing substances. One of the major air pollutants, it is emitted in large quantities by exhaust of gasoline-powered vehicles.
Carbon Intensity	The amount of carbon dioxide produced for every unit of energy. For the purposes of this IRP, carbon intensity will be measured in pounds of carbon dioxide per megawatt-hour.
Carrying Costs	Annual costs associated with investment in assets including depreciation, debt interest, equity return, income taxes, and property taxes.
Clean Air Act (CAA)	The primary federal law enacted by the U.S. Congress to govern the regulation of emissions into the atmosphere on a national level. The primary responsibility for administering the CAA was given to EPA which develops and enforces regulations to protect the general public from exposure to airborne contaminants.
Coal Combustion Residual (CCR)	Referred to as coal ash, CCRs are currently considered exempt wastes under the Beville amendment to the Resource Conservation and Recovery Act (RCRA). They are residues from the combustion of coal in power plants and captured by pollution control technologies, such as scrubbers.
Coincident Peak	An individual customer's peak coincides with the system peak, meaning they are contributing to that peak hour.
Combined Cycle (CC)	Twin-stage natural gas-fired power plants that deliver higher fuel efficiency. In the first stage, a gaseous fuel source (natural gas, gaseous coal, etc.) is combusted in a gas turbine. The turbine is used to drive an electric generator. In the second stage, waste heat is captured from the gas turbine's hot exhaust gases in a heat recovery steam generator (HRSG). The steam that is produced in the HRSG is used to drive a steam turbine and produce additional electricity. This beneficial use of the residual heat content in the gas turbine's exhaust stream contributes to the excellent fuel efficiency of the combined cycle power plant.
Combustion Turbines (CT)	Also referred to as a simple cycle gas turbine, these electric generators operate on a principle similar to the engines on jet airplanes. Ambient air is compressed to high pressures in the compressor section of the machine. A gaseous fuel source is added to this compressed air and combusted in the combustor section. The resulting hot gases are then expanded through a turbine section that provides the driving force for both an electric generator and the compressor section.
Commercial Operation Date	The date when an operating utility formally declares a new generation resource to be available for the regular production of electricity.
Co-optimization	Process of procuring energy and ancillary services simultaneously in the market clearing processes.



Compact Fluorescent Lamp (CFL)	A type of fluorescent lamp. Compared to incandescent lamps giving the same amount of visible light, CFLs use less power and have a longer rated life.
Competitive Procurement Procedure	Any solicitation process initiated to meet KYMEA energy requirements. The Competitive Procurement Process shall include, as appropriate, preparing and conducting the solicitation, bid evaluation and selection, and negotiating the definitive agreement(s), but shall not include management or implementation of such agreement(s) after their execution.
Concentrated Solar Power (CSP)	Technologies that concentrate solar energy to generate electricity. This class of solar technologies includes solar troughs, power towers, dish stirring, and concentrating photovoltaics.
Conditional Demand Analysis (CDA)	Statistical approach that allocates total household electricity demand during a period into components associated with a particular electricity-using appliance or end-use.
Congestion	A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of energy to serve the next increment of load, exclusive of losses, at different locations on the transmission system is unequal.
Congestion costs	Charges assessed and redistributed due to electricity network constraints.
Consumption (Energy Use)	The total amount of electricity consumed over a period of time, measured in megawatt-hours. Consumption varies from demand in that demand is the rate at which electricity is being used at any one given time.
Conventional Resources	Conventional generating resources include a broad class of technologies that use coal, nuclear, natural gas, or fuel oil to generate electricity. Generally, conventional resources are dispatchable.
Cooling Degree-day	A measure of how warm a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the base temperature (65 degrees) from the average of the day's high and low temperatures, with negative values set equal to zero. Each day's cooling degree-days are summed to create a cooling degree-day measure for a specified reference period. Cooling degree-days are used in energy analysis as an indicator of air conditioning energy requirements or use.
Critical Notices	Pipeline issuances that provide information on conditions that affect natural gas scheduling or adversely affect scheduled gas flow.
Curtailable Load	Electricity deliveries that are subject to interruption by the grid operator.
Day-Ahead Markets	Bid-based day-ahead market using security constrained unit commitment and security constrained economic dispatch (SCUC and SCED).
Decentralization	Involves the shift away from large, central-station power plants to smaller, often variable resources that are located on local, low-voltage electricity distribution networks, or "behind the meter" at homes and businesses.
Debt Financing	Providing capital by selling bonds, bills, or notes to individuals or institutions.
Delivered Cost	Refers to the cost of power produced by a generating unit (or a purchased power contract) where the cost of delivering the electric power from the generating source to the load center (area of customer consumption) has also been included in the cost.
Delivery Point (s)	An industry-designated location at which delivery may be made in fulfillment of contract terms.



Demand	The rate at which electricity is being used at any given time, measured in megawatts. Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time.
Demand Elasticity	The degree to which demand changes relative to a change in price.
Demand Response (DR)	Mechanisms designed to provide incentives to customers to reduce their load in response to high electric market prices or electric system reliability concerns. Demand response measures could include direct load control programs, such as cycling of air conditioner load, or customer-initiated load reductions. Price response programs include real-time pricing, dynamic pricing, critical peak pricing, time-of-use rates, and demand bidding or buy-back programs.
Demand-Side Management (DSM)	The planning, implementation, and monitoring of utility activities designed to encourage residential and business customers to modify patterns of electricity usage, including the timing and level of electricity demand.
Demarginalization	Refers to the modified set of resources that can provide the next needed, or "marginal," increment of energy at zero additional costs (e.g., renewables), or very low additional costs (e.g., highly efficient gas-fired generation).
De-pancaked Rates	De-pancaked rates is a reference to a specific 2016 FERC Order which was conditioned on the LG&E/KU withdrawal from MISO. In the order, FERC directed LG&E/KU to amend their open access transmission tariffs to state explicitly that existing customers will receive service subject to the same prices, terms and conditions that they would have received if the utilities had not withdrawn from MISO. This ruling provided transmission and ancillary services at "de-pancaked" rates to a group of Kentucky municipals that rely on LG&E/KU's transmission service.
Digitalization	Refers to the revolution in information and communication technologies and platforms that will continue to disrupt nearly everything in the U.S. economy, including energy services.
Discount Rate	An interest rate used to convert future cash flows to present values.
Dispatchable	Generating units (or purchased power contracts) whose rate of power production can be adjusted or varied based upon economic or other considerations. Different types of generating units have varying degrees of dispatchability either for technical or economic reasons.
Distributed Energy	A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid or the customer's electrical system. Distributed generation can serve as a primary or backup energy source and can use various technologies, including combustion turbines, reciprocating engines, fuel cells, wind generators, and solar photovoltaics.
Distribution	The delivery of energy to retail customers.
Dry Cooling	The typical steam power plant requires cooling water to improve overall cycle efficiency by returning the exhaust steam to a liquid state that can then be returned to the boiler to produce more steam. In a dry-cooled power plant, the exhaust steam is cooled by use of air-cooled condensers, thereby eliminating the use of water from this portion of the power production process; however, the air-cooled condensers are more expensive and overall plant efficiency is reduced versus water-cooled plants.
Dual-fueled(or dual-fired)unit	A generating unit that can produce electricity using two or more fuels. In some of these units, only the primary fuel can be used continuously; the alternate fuel(s) can be used only as a start-up fuel or in emergencies.



Eastern Interconnection	One of two major alternating current electric grids in North America, which encompasses the area east of the Rocky Mountains and a portion of northern Texas. The Eastern Interconnection consists of 36 balancing authorities: 31 in the United States and 5 in Canada.
Effluent	Wastewater, treated or untreated, that flows out of a treatment plant, sewer, or industrial outfall. Generally refers to wastes discharged into surface waters.
Electric Generating Units (EGU)	A solid fuel-fired steam generating unit that serves a generator who produces electricity for sale to the electric grid.
Electric Reliability Council of Texas (ERCOT)	The Electric Reliability Council of Texas (ERCOT) serves as an independent system operator, managing the flow of electrical power to 24 million customers in the state of Texas, representing approximately 90% of Texas' electrical load. ERCOT operates a competitive wholesale electricity market, ensuring reliability over more than 46,000 miles of transmission lines, for approximately 550 generating units and for its customers in Texas.
Electric Utilities	All enterprises engaged in the production and/or distribution of electricity for use by the public, including investor-owned electric utility companies; cooperatively-owned electric utilities; government-owned electric utilities (municipal systems, federal agencies, state projects, and public power districts).
Emergency Operations Resource	Emergency Operations Resource: An online Generation Resource that is started, synchronized and injects Energy, or a Demand Response Resource that reduces its Energy consumption, within two hundred forty (240) minutes but over sixty (60) minutes of being notified and that has a minimum run time of over one hour but less than four hours and that will participate in setting prices.
Emissions	Discharges into the atmosphere from stacks, other vents, and surface areas of commercial and industrial facilities; from residential chimneys; and from motor vehicle, locomotive, or aircraft exhaust.
Energy	The amount of electricity a generation resource produces, or an end user consumes, in any given period of time. It is usually measured in units of kilowatt-hours, megawatt-hours, or gigawatt-hours.
Energy Efficiency	In the context of resource planning, energy efficiency refers to actions taken by consumers to reduce their overall consumption of electric energy. These reductions could be the result of installation of more efficient equipment, improvements to the thermal envelopes of structures, or behavioral changes. Energy efficiency improvements can be encouraged through utility-sponsored programs, mandated by building codes or other standards or simply implemented by the customer.
Energy Savings	A reduction in the amount of electricity used by end users. In this IRP, it specifically refers to the reduction that is result of participation in energy efficiency programs and load management programs.
Energy Mix	The percentage of each type of energy generated in a scenario or profile. Together, the percentages for each scenario add up to 100%.
Environmental Protection Agency (EPA)	A governmental agency established in 1970 to research, monitor, and establish standards that protect human health and the environment. The EPA also has the authority to enforce regulations when necessary, although normally the states implement them.
Exchange	A marketplace in which shares, options and futures on stocks, bonds, commodities and indexes are traded.



Extended Locational Marginal Price (ELMP)	MISO extends the LMP and MCP by allowing the cost of committing Fast Start Resources, the Energy cost of Fast Start Resources dispatched at limits, and Emergency Demand Response Resources to set Energy and reserve prices. This process is known as the Extended LMP.
Fast Start Resource	An online Generation Resource that is started, synchronized and injects Energy, or a Demand Response Resource that reduces its Energy consumption, within sixty 60 minutes of being notified and that has a minimum run time of one hour or less and that will participate in setting prices; or, an offline Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within ten 10 minutes of being notified and that has a minimum run time of one hour or less, and that will participate in setting prices. A Fast Start Resource does not include fuel-limited resources such as pumped storage, run-of-river hydro, and wind resources.
Federal Energy Regulatory Commission (FERC)	A governmental agency that regulates the interstate transmission of natural gas, oil, and electricity and wholesale power transactions. FERC also regulates natural gas and hydropower projects.
Financial Markets	Markets where financially settled products (instruments) are traded (bought and sold). In commodity markets, it is markets where financially settled commodity derivatives are traded. Nymex is purely financial, where any residual delivery obligations on the futures contracts are matched and settled physically off-exchange by the matched parties. ICE trades both physically and financially settled products. Brokers also do both physical and financial transactions. Financial markets are also a term used for capital markets where stocks, bonds, T-Bills, foreign exchange and other financial instruments are traded.
Financial Transactions	A transaction that involves only the exchange of money, with no physical delivery.
Financial Transmission Right	A financial instrument that entitles the holder to receive compensation for Congestion Costs that arise when the transmission grid is congested in the Day-Ahead Energy Market, and differences in Day-Ahead Locational Marginal Prices (LMPs) result from the dispatch of generators to relieve the congestion.
Firm Transportation	Energy network service assuring market participants of a specified quality and quantity of service under normal operating conditions. May ascribe rights to specific receipt and/or delivery points for service. Network facilities are generally designed, installed, and dedicated to meeting firm transportation service requirements.
First Contingency Reliability Criteria	The requirement that an electric system be planned and operated so that it can safely withstand the loss of the largest single system element (i.e. power plant or transmission line).
Fixed Price Transactions	Buying or selling a commodity at a fixed price. For example, fixed physical gas prices are used to form indices at some locations; and fixed basis prices plus Nymex settled prices are used to form price indices at other locations.
Flexibility	The ability to anticipate and adapt to frequent, significant changes in generation output and demand; and enable new sources of flexibility.
Flexible Resource	Dispatchable generation resource capable of reaching full capacity in under an hour from cold start.
Floating Price Transactions	Buying or selling a commodity at a price that is not fixed and will be set by mutual agreement, usually based on a published price index.



Force Majeure	Disruptions in service caused by natural disasters (earthquakes, hurricanes, floods, etc.); wars, riots, or other major upheaval; or, performance failures of parties outside the control of the contracting party.
Forward Price Curve	The set of prices of contracts for delivery of a good over a span of time in the future. For example Nymex deals in natural gas futures contracts for 72 months in the future. Each of the 72 contract months end-of-day settlement price forms the forward curve for Nymex gas futures for the day.
Fuel-adjustment Clause	A provision of a power sales agreement or rate schedule that allows for the electricity price to be changed based on changes in the price of the fuel used to generate the power.
Fuel Cell	A device that converts chemical energy into electrical energy using a fuel. Fuel cells require a constant supply of fuel and oxygen for its chemical reaction unlike batteries where the chemicals react with each other to provide the electricity.
Futures Market	A market in which contracts for future delivery of a commodity or a security are bought and sold. Nymex is the primary futures market for energy commodities in the United States.
Gas Turbine	An engine, similar to a jet engine, that burns fuel to produce a large volume of exhaust gases that expand through a series of precision blades to rotate a shaft. The shaft may turn an electric generator; such plants can be built at a lower cost than other large power plants, but they are relatively inefficient and therefore more expensive to operate.
Generation	The act of producing electrical energy from other forms of energy (such as thermal, mechanical, chemical or nuclear); also, the amount of electric energy produced, usually expressed in kilowatthours (KWh) or megawatthours (MWh).
Generator	An electrical device used to convert mechanical energy to electrical energy. The generator moves a conductor through a magnetic field and directs the current produced by the induced voltage to an external electric circuit.
Geothermal	Energy produced below the Earth's crust in a layer of hot and molten rock called magma, heating nearby rock and water that has seeped deep into the Earth. At geothermal power plants, wells are drilled into the rock to more effectively capture the hot water and steam to be used to drive electric generators.
Gigawatt (GW)	1 billion watts, the same as 1,000 Megawatts, or 1 million kilowatts.
Greenhouse Gas (GHG)	A collection of gaseous substances, primarily consisting of carbon dioxide, methane, and nitrogen oxides, which have been shown to warm the earth's atmosphere by trapping solar radiation. Greenhouse gases also include chlorofluorocarbons, a group of chemicals used primarily in cooling systems and which are now either outlawed or severely restricted by most industrialized nations.
Grid (Power or electric)	An interconnected network of electric power transmission lines. The United States power grid, which covers most of the country as well as parts of Canada and Mexico, is made up the Eastern Interconnection, Western Interconnection, and Texas Interconnection. These networks include extra-high-voltage connections between individual utilities, which transfer electrical energy from one part of the network to another. The Interconnects distribute electricity in their respective areas via a network of smaller units that enable better management of power distribution.
Groundwater	Water that is held in soil or in rocks underground. Groundwater is distinct from surface water, which is water held in lakes and rivers.



Hazardous Air Pollutants (HAP)	Substances covered by air quality criteria, which may cause or contribute to illness or death.
Heat Rate	A measure of the amount of thermal energy required to produce a given amount of electric energy. It is usually expressed in British thermal units per kilowatt-hour (Btu/kWh). The performance of a power plant is measured by its fuel consumption rate (Btu/hr) and the corresponding amount of electric energy generated; thus, heat rate can be used to indicate the efficiency with which thermal energy is converted into electric energy.
Heating Degree-day	A measure of how cold a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the average of the day's high and low temperatures from the base temperature (65 degrees), with negative values set equal to zero. Each day's heating degree-days are summed to create a heating degree-day measure for a specified reference period. Heating degree-days are used in energy analysis as an indicator of space heating energy requirements or use.
Heating, Ventilating and Air Conditioning (HVAC)	Technology which provides indoor air comfort.
Hedging	The attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks. For example, a company that has an obligation to purchase fuel oil in six months may want to eliminate the risk that prices will increase before that time. In this case, the company could hedge, or reduce, that risk by purchasing a futures contract that provides the right to purchase fuel oil at a fixed price. Any profit or loss on the futures contract should offset the effects of higher or lower oil prices at the time the company needs to buy oil.
Henry Hub	A location near the coastal town of Egan, LA and the Texas border where more than a dozen major natural gas pipelines converge and exchange gas. It is owned and operated by Sabine Pipeline, a subsidiary of Chevron-Texaco. Widely used for physical trading, including physical delivery of the Nymex natural gas futures contracts. Henry Hub is also one of the most widely used points for monthly and daily price indexes.
Hg (Mercury)	See Mercury.
Hub	In the context of the electric grid, a hub is a location on the transmission network having a high concentration of interconnected transmission lines, generating sources, and/or counterparties willing to transact power trades such that this becomes a location having a great deal of commercial activity.
Hybrid Cooling	A type of technology that utilizes a combination of water cooling and dry cooling techniques. The relative contribution from each is dependent upon the plant design, weather conditions, and water consumption policies. See also Dry Cooling.
Imbalance Energy (Imbalance)	Discrepancy between the amount that a seller contracted to deliver and the actual volume of power delivered. Imbalances are resolved through monetary payment.



Index	Also Price Index. A representative price usually computed and published by a trade journal or transaction venues (e.g., ICE), using information from actual fixed price transactions. Buyers and sellers not active in a market may transact at a price index that is representative of the market. It is also used by state regulators as a benchmark for distributor pass-through of commodity costs to consumers. Market participants who are active and willing to transact at fixed prices during the trading period, in effect, are the ones forming the index prices. A price index based on large volumes, many transactions and many counterparties, is representative of a liquid and competitive market point, but indices formed at points with few transactions may be less reliable.
Installed Capacity	The total potential output of a given set of existing generators, usually measured in megawatts. A share of potential (not actual) output that load-serving entities are required to procure as an administrative measure to ensure adequate generation supply. (See also Capacity Markets, Locational Installed Capacity).
Intercontinental Exchange (ICE)	Founded in 2000, ICE is an on-line commodity market place and exchange.
Integrated Gasification Combined Cycle (IGCC)	A power generation technology which allows a reduction of emissions by combining two technologies: (1) coal gasification, which uses coal to create a clean-burning gas; and, (2) combined cycle generation.
Intensity	Metric employed to characterize the emission of pollutants, relative to the power produced. For example, tons of CO ₂ emitted per MWh or gallons of water used per MWh can be used to help characterize the energy intensity of the system resources independent of load growth.
Interconnection	A connection between two electric systems permitting the transfer of electric energy in either direction. Additionally, an interconnection refers to the facilities that connect a generator to a system.
Intermediate Resource	Generation resources that usually fulfill a somewhat flexible role in the generating system. During some times of the year, these generating units will be started in the morning hours, used to meet daytime peak loads and then brought off-line in the evening. The operation may change during heavier load times of the year when these units may operate in more of a baseload manner and remain on-line for all hours of the day.
Intermittent (or Variable [Energy]) Resource	Generating resources that have some degree of variability in the production pattern, typically due to weather conditions. An example of an intermittent generating source is a wind project. The power output from the wind project is entirely dependent upon the wind conditions and will fluctuate with changes in wind conditions.
Interruptible or Nonfirm Transportation	Transmission service that is reserved and scheduled on an as-available basis and is subject to curtailment or interruption.
Investment Tax Credit (ITC)	Allows taxpayers to take a dollar-for-dollar reduction in the amount of federal income taxes that must be paid. Certain qualified facilities are characterized as energy property and are the reduction depending on the technology. A taxpayer cannot take both an ITC and PTC for a facility that could qualify for both; one must elect to receive either an ITC or PTC for each project.
Independent System Operator (ISO)	An independent, Federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system. (See also Regional Transmission Organization).



Kentucky Department for Environmental Protection (KDEP)	Administers a variety of programs to improve the health and welfare of citizens and ensure the quality of Kentucky's air, land, and water resources are consistent with USEPA regulations, policy, and guidelines.
Kentucky Public Service Commission (PSC or Commission)	The Kentucky Public Service Commission is a three-member administrative body with quasi-legislative and quasi-judicial duties and powers regulating more than 1,100 utilities. The Commission regulates the intrastate rates and services of investor-owned electric, natural gas, telephone, water, and sewage utilities, customer-owned electric and telephone cooperatives, water districts and associations, and certain aspects of gas pipelines.
Kentucky Revised Statutes (KRS)	The official compilation of rules that govern the Commonwealth of Kentucky's agencies, boards, and commissions.
Kilowatt (kW)	Unit of measure for demand. One thousand Watts.
Kilowatt-Hour (kWh)	Unit of measure for energy. The equivalent of one thousand Watts used steadily for one hour.
Kurtosis	Kurtosis is a measure of the "tails" of the probability distribution of a real-valued random variable. Positive kurtosis skews the distribution up (skinnier tails), while negative kurtosis skews the distribution down (fatter tails).
Light-Emitting Diode (LED)	A semiconductor light source increasingly used for lighting. LEDs present many advantages over incandescent light sources including lower energy consumption, improved robustness, smaller size, faster switching, and greater durability and reliability.
Liquefied Natural Gas (LNG)	Reducing the temperature of natural gas to -259 degrees Fahrenheit at atmospheric pressure will convert the gas into a liquid, with a volume about 1/600 compared to its volume as a gas.
Load	The moment-to-moment measurement of the power requirement in the entire system.
Load Center	A point at which the load of a given area is assumed to be concentrated.
Load Control	The process of managing demand requirements in order to achieve a desired load pattern. Load control devices are installed on customers' appliances or services to reduce the electric system's demand when a peak situation is about to occur. Examples of load control devices would include controls on air conditioner compressors, hot water heaters and dual-fuel heaters.
Load Factor	A measure of natural gas pipeline utilization equal to average gas flows over a given time divided by an assumed maximum or peak flow.
Load Pocket	A geographic area that has a high demand of energy constrained by transmission import limitations. For example, the metro Phoenix area is considered a load pocket.
Loads & Resources Table	Presents the annual expected resource needs and additions.
Load-serving Entity (LSE)	Any entity, including a load aggregator or power marketer, that serves end-users within a control area and has been granted the authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-users located within the control area.
Load Shedding	The reduction of system demands by systematically and in a predetermined sequence interrupting the load flow to major customers and/or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations.



Local Distribution Company (LDC)	Any firm, other than a natural gas pipeline, engaged in the transportation or local distribution of natural gas and its sale to customers that will consume the gas.
Locational Marginal Price (LMP)	The cost of providing the next MW of electrical energy at a specific location on the transmission grid. This includes a marginal congestion component and marginal loss component in addition to marginal energy component to account for losses and congestion.
Loss of Load Expectation (LOLE)	The expectation that generation resources will fall short of the resource need. The LOLE is usually set as 1 day in 10 years.
Losses on Peak	Total electric energy losses during the hour of greatest energy demand. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution equipment (wire, transformers, etc.).
Low NOx Burner (LNB)	A type of burner that is typically used in utility boilers to produce steam. Air used for combustion is split into two or more parts. The initial combustion, which occurs at a high temperature, takes place in an oxygen-deficient condition to form molecular nitrogen (N ₂) instead of NO _x . Further down the flame, additional air is added to complete the combustion after the nitrogen has been driven out of the coal as N ₂ .
Lowest Achievable Emission Rate (LAER)	The most stringent emission limitation derived from either of the following: (a) the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or, (b) the most stringent emission limitation achieved in practice by such class or category of source. The emissions rate may result from a combination of emissions-limiting measures such as: (1) a change in the raw material processed; (2) a process modification; and, (3) add-on controls.
Major Modification	Any physical change or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.
Major Sources	Term used to determine applicability of permitting regulation to stationary sources. For Title V of the Clean Air Act, refers to sources of air pollution that emit or have the potential to emit 100 tons per year or more of any criteria air pollutant.
Margin Requirement	Money or collateral deposited with a broker, clearing member or clearing organization intended to hold futures contracts and cover changes in the value of futures contracts. Margin is one way of dealing with credit exposure. Properly designed margining, along with effective clearing, has helped exchanges stay in business even as occasional large defaults occur.
Marginal Electric Generating Unit	In organized wholesale markets, the price of the marginal source of electricity usually sets the price of the unit providing the next increment or decrement of energy, which price usually sets the price for all generation.
Mark-to-Market	Adjustment of the book value or collateral value of a security – including a security such as a multi-year contract – to reflect current market value for the applicable period.
Market	A venue where participants buy and sell products or services. Usually there is agreement of product description and some standard terms to enable determination of value and price.
Market Clearing Price (MCP)	The marginal cost to serve market-wide and zonal reserve requirements.



Market Concentration	A measure, usually an estimate, of the market share of a participant or groups of participant in the overall market or a submarket (a given region, product, or time, for example).
Market Participant	A market buyer or a market seller, or both, that meets reasonable credit-worthiness standards established by the market operator.
Market Power	The ability of any market participant with a large market share to significantly control or affect price by withholding production from the market, limiting service availability, or reducing purchases.
Market Structure	The rules, mechanisms and processes, under which a market operates to form prices, provide benefits and introduce risks to participants, and ultimately end consumers. Structure could enhance or inhibit competition, create just and reasonable outcomes, provide economically efficient incentives, or introduce unintended consequences, including adverse market outcomes.
Maximum Achievable Control Technology (MACT)	The standards which are established by EPA to require the maximum degree of emission reduction that EPA determines to be achievable for hazardous air pollutants. These standards are authorized by Section 112 of the Clean Air Act.
Megawatt (MW)	One megawatt equals one million watts. See Watt.
Megawatt-Hour (MWh)	One million watt-hours See Watt-Hour.
Member Resources (or member-sited resources)	Resource options which rely upon active participation by customers to produce either a reduction in energy consumption or peak demand. These customer-side resource programs include energy efficiency programs, demand response programs, and alternative rate schedules. Energy efficiency programs are directed at achieving reductions in customer energy consumption through more efficient equipment or improvements to a building's thermal envelope. Demand response programs generally target reductions during the highest usage periods of the year through special rate schedules (such as time-of-use prices), energy storage options, or other similar programs.
Merchant Generator	A generating plant built with no energy sales contracts in place.
Mercury	A naturally-occurring element that is found in air, water and soil. Coal contains mercury and when coal is burned, mercury is released into the environment.
Midcontinent Independent System Operator (MISO)	An Independent System Operator (ISO) and Regional Transmission Organization (RTO) that provides open-access transmission service and monitoring for high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region that includes much of Arkansas, Mississippi, and Louisiana. MISO also operates a real-time energy market.
Must Take Generation	Electricity production that must be taken when it is produced by the utility. Generally refers to qualifying facilities under the Public Utility Regulatory Policies Act (PURPA).
Nameplate Capacity	A rating for each generating unit that specifies the maximum expected output of the generating unit.
National Ambient Air Quality Standards (NAAQS)	The standards established by EPA under authority of the Clean Air Act that apply to outdoor air throughout the country. Primary standards are designed to protect human health, with an adequate margin of safety.



National Environmental Policy Act (NEPA)	Establishes a process by which federal agencies must study the environmental effects of their actions, so these effects can be taken into consideration during federal decision-making.
Native Load	Wholesale and retail customers that the electric transmission provider is obligated to serve.
Natural Gas	A naturally occurring combustible mixture of gases recovered from the earth from wells. It is composed predominantly of methane, but contains other light hydrocarbons and impurities.
Net Present Value (NPV)	Method for evaluating the cost or profitability of an investment. Individual future cash amounts are discounted back to their present values and then summed.
New Source Performance Standards (NSPS)	Pollution control standards issued by the Environmental Protection Agency.
New Source Review (NSR)	A permitting program that was established by Congress as part of the 1977 Clean Air Act Amendments. NSR is a preconstruction permitting program to ensure air quality is not significantly degraded from the addition of new and modified factories, boilers, and power plants and that advances in pollution control occur with industrial expansion.
New York Mercantile Exchange (Nymex)	The centralized exchange where CFTC-sanctioned natural gas and electricity futures are traded in the United States. Nymex is also a central credit clearing house where the credit risk of counterparties is transferred and risk-managed through clearing membership, reserve funds and risk management protocols with CFTC oversight as a designated clearing organization (DCO).
Nitrogen Oxide (NOx)	Compounds of nitrogen and oxygen formed by combustion under high temperature and high pressure and a major contributor to the formation of ozone.
Non-Spin Reserves	A generating reserve not connected to the system but capable of serving demand within a specified time, usually ten minutes.
North American Electric Reliability Corporation (NERC)	NERC is a non-government organization which has statutory responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices.
NOx Budget Trading Program (NBP)	An ozone season cap-and-trade program intended to help states meet their NOx state implementation plan (SIP) required reductions. Twenty-one states and the District of Columbia began participating in 2003–04 or will participate in the future.
Nuclear Regulatory Commission (NRC)	The federal agency responsible for the regulation and inspection of nuclear power plants to assure safety.
Nuclear Fuel	Fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.
Off-Peak	Period of relatively low system demand. These periods often occur in daily, weekly, and seasonal patterns.
On-Peak	Periods of relatively high system demand. These periods often occur in daily, weekly, and seasonal patterns.
Open Access	Order No. 888 requires utilities to allow others to use their transmission and distribution facilities, to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee.



Operating Reserves (or reserves or Contingency Reserves)	A combination of spinning and non-spinning reserves. Operating reserve is the portion of all reserves KYMEA is required to carry over and above firm system demand to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. KYMEA carries a 15% reserve margin.
Operation & Maintenance (O&M)	Actions taken after construction to ensure that facilities constructed will maintain performance by being properly operated and maintained to achieve normative efficiency levels in an optimum manner.
Outage	The period during which a generating unit, transmission line, or other facility is out of service. A forced or unplanned outage is the shutdown of a generating unit, transmission line or other facility for emergency reasons. A scheduled or planned outage is the shutdown for inspection or maintenance, in accordance with an advance schedule.
Ozone	Ozone, the triatomic form of oxygen (O ₃), is a gaseous atmospheric constituent. In the troposphere, it is created both naturally and by photochemical reactions involving gases resulting from human activities (photochemical smog). The layer of ozone that begins approximately 15 km above Earth and thins to an almost negligible amount at about 50 km, shields the Earth from harmful ultraviolet radiation from the sun.
Particulate Matter	Particle pollution in the air that includes a mixture of solid particles and liquid droplets.
Peak Demand (or Peak Load or Peak)	The greatest demand that occurred or is expected to occur during a prescribed time period.
Peaking Resources	Technologies used to respond to high customer demands during the hot summer afternoons. These could include combustion turbines and DR measures and may include short-term market purchases.
Peaking Units	These generation units usually see relatively infrequent service during the non-summer months. During the summer, peaking units are used during the hot summer afternoons in response to high customer demands. It is not unusual for peaking units to operate less than 10% of the hours during the year.
Peakshaving LNG Facility	A liquefied natural gas plant that supplies a gas pipeline system during peak-use periods. During slack periods the liquefied gas is stored. With the need for additional gas, the liquid product is gasified and fed into local distribution and gas pipeline systems.
Physical Basis	Describes a physical natural gas purchase for the following month where the price is tied to the closing price of the expiring Nymex futures contract.
Pivotal Supplier	A power supplier whose capacity must be used to meet peak demand and whose capacity exceeds the market's supply margin.
Planning Horizon	For the purpose of this IRP, the three planning periods considered are: Existing-Term: May 1, 2019 – May 31, 2022 (3 Years) Near-Term: June 1, 2022 – May 31, 2027 (5 Years) Long-Term: June 1, 2027 – May 31, 2042 (14 Years)
Planning Reserve Margin Requirement (PRMR)	A measure of making sure there exists enough generation capacity to meet demand.
Plant Factor	The capacity factor of an entire generating facility including all available generating units. See capacity factor.



PM10	Particles with diameters that are 10 micrometers or smaller. Sources of particles include combustion, crushing or grinding operations, and dust from paved or unpaved roads.
Power Marketer	A business entity engaged in buying and selling electricity. Power marketers do not usually own generating or transmission facilities. Power marketers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. These entities must file with FERC to obtain status as a power marketer.
Prevention of Significant Deterioration (PSD)	EPA program in which state and/or federal permits are required in order to restrict emissions from new or modified sources in places where air quality already meets or exceeds primary and secondary ambient air quality standards.
Production Tax Credit (PTC)	Allows a tax credit for the generation of qualified energy from qualified facilities. The PTC amounts, credit periods, and definitions of qualified facilities are technology-specific. Qualified energy resources include: wind, closed-loop biomass, open-loop biomass, geothermal, solar, small irrigation power, municipal solid waste, qualified hydropower production, and marine and hydrokinetic renewable energy. A taxpayer cannot take both an ITC and a PTC for a facility that could qualify for both – one must elect to receive either an ITC or PTC for each project.
Project Financing	A form of asset-based financing in which a firm finances a discrete set of assets (the project) on a stand-alone basis.
Purchased Power Agreement (PPA)	A contractual agreement between two entities for the sale and purchase of electric energy and capacity from a specific generating unit, utility system, or unspecified wholesale market sources.
Ramp Rate	The rate at power system load or generator output varies, or the limits to such rates due to mechanical or reliability considerations.
Rate Pancaking	Rate pancaking is the stacking or accumulation of transmission charges for service that use the transmission facilities of multiple transmission providers. RTOs were formed to end subjecting transmission customers to multiple transmission charges for long-distance power deliveries.
Real-Time Market	Bid-based real-time market solved with security constrained economic dispatch.
Real-Time Operations	Operational activity which manages the economic commitment of KYMEA's generation resources to match the system load on a real-time basis. Requires making decisions to optimize system operation to provide lowest cost, reliable power to KYMEA customers.
Real-Time Pricing	The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.
Real-Time Traders	Individuals involved solely in commodity trading of power, specifically electricity.
Regional Haze Rule	Requirements established by EPA to address source-by-source visibility impairment.
Regional Transmission Organization (RTO)	A voluntary organization of electric transmission owners, transmission users and other entities approved by FERC to efficiently coordinate electric transmission planning (and expansion), operation and use on a regional (and interregional) basis. Operation of transmission facilities by the RTO must be performed on a non-discriminatory basis.



Regression Models	A statistical technique used to find relationships between variables for the purpose of predicting future values.
Renewable Energy	An energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.
Request for Proposal (RFP)	A competitive solicitation for suppliers, often through a bidding process, to submit a proposal on a specific commodity or service.
Reliability Commitments	SCUC-based reliability commitment processes to ensure that sufficient generation will be online to meet forecast real-time requirements.
Reliability Coordinator	The entity that is the highest level of authority who is responsible for the Reliable Operation of the BES, has the Wide Area view of the BES, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Imperative	The shared responsibility of utilities, states and MISO to address the host of complex and urgent challenges to electric system reliability in the MISO region.
Reliability Must Run (RMR)	A unit that must run for operational or reliability reasons, regardless of economic considerations. Also called a reliability agreement.
Reserve Margin	The percentage of installed capacity exceeding the expected peak demand during a specified period.
Residential Direct Load Control	Demand response programs where the utility or a third-party contractor can remotely control customer-specific loads and reduce or cycle the energy consumption for a specified period of time.
Resource Conservation and Recovery Act (RCRA)	Gives EPA the authority to control hazardous waste from the "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also set forth a framework for the management of non-hazardous solid wastes.
Resource Models	A set of mathematic models to represent resource physical or business constraints.
Revenue Requirements	Annual revenue level required to supply customers energy needs, including: (1) carrying charges on existing and future generation, future transmission over and above KYMEA Ten Year Transmission Plan, and capital expenditures on existing generation; (2) fuel costs; (3) purchase power costs; (4) operating and maintenance costs for existing and future generation; (5) energy efficiency program and incentive costs; (6) distributed energy program and incentive costs; and, (7) power plant emissions costs including SO ₂ and CO ₂ . Revenue requirements as used in the resource plan filing do not include costs associated with existing transmission, existing and future distribution, or sales tax on retail electric sales.
Risk Management	The process of analyzing exposure to risk and determining how to best handle such exposure.
Rolling Blackouts	A controlled and temporary interruption of electrical service. They are necessary when a utility is unable to meet heavy peak demands because of an extreme deficiency in power supply.
Safe Harbor	The ability of management to discuss in good faith a company's prospects and financial projections with analysts and investors without fearing litigation.



Scenario Analysis	Refers to the grouping together of a set of assumptions of key uncertain variables that could potentially all occur in tandem. The goal of scenario analysis is to illustrate the impact to the portfolios of multiple key variables being stressed in a plausible manner. Results of these studies provide information on diversity, cost, environmental impacts, robustness and overall risk to assist in the selection of a resource plan.
Security Constrained Economic Dispatch (SCED)	Security-constrained economic dispatch is an area-wide optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the area's generation fleet and transmission system.
Security Constrained Unit Commitment (SCUC)	Security Constrained Unit Commitment Transmission Constraint: A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Selected Plan	The best-fitting plan chosen by KYMEA that comprehensively considers a wide range of supply- and demand-side options.
Selective Catalytic Reduction (SCR) Controls	A post-combustion pollution control technology that removes NOx emissions from an air stream. Ammonia (NH3) is injected into the flue gas downstream from the combustion process and upstream from a catalyst bed. The NH3 reacts with the NOx on the catalyst surface to form nitrogen (N2) and water vapor (H2O).
Self-Dispatching	Resources that generate based on an outside stimulus, for example solar when the sun is shining on the panels. It also refers to generation that the utility cannot start or curtail at will.
Service Territory (Retail)	The area where a utility provides power.
Short Position	The selling side of the open futures contract; A trader whose net position in the futures market shows an excess of open sales over open purchases.
Simple Cycle	See Combustion Turbine.
Skewness	Skewness is a measure of the asymmetry of the probability distribution of a random variable about its mean. Negative skew commonly indicates that the tail is on the left side of the distribution, and positive skew indicates that the tail is on the right.
Societal Cost Test (SCT)	A variant of the Total Resource Cost Test. It measures the impacts of DSM on society as a whole by including externality costs of power generation not captured by the market.
Solar Photovoltaic (PV, or Solar PV)	A method of generating electrical power by converting solar radiation directly into electricity.
Solar Thermal	A method for harnessing solar energy for thermal energy.
Spinning Reserves	Available generating capacity that is synchronously connected to the electric grid and capable of automatically responding to frequency deviations on the system.
Spot Market	A commodities or securities market in which goods are sold for cash and delivered immediately.
Standby Generation	Customer-owned generation resources, typically diesel- or gas-fired, that provide customers with a guaranteed source of power in the event that either power quality or reliability issues occur with their local utility.



Start-up Costs	The costs associated with starting a power plant. These costs have become more of a consideration as more variable energy resources have been added to the electricity system and start-ups have become more frequent for some types of generation.
Steam Plant	A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.
Sulfur Dioxide (SO ₂)	A colorless gas of compounds of sulfur and oxygen that is produced primarily by the combustion of fossil fuel.
Summer Peak	See Peak Demand.
Swaps	An exchange of streams of payments over time according to specified terms. A common type is a fixed-for-floating swap, in which one party agrees to pay a fixed price in return for receiving a changing price (e.g., spot price) from another party.
Terawatt-Hour (TWh)	A terawatt-hour is a unit of energy equal to outputting one trillion watts for one hour.
Total Member Load Peak	The greatest demand for energy during a specified time period by customers that KYMEA has a requirement to serve.
Total Resource Cost Test (TRCT)	Measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's.
Transmission	The transportation of bulk energy along a network or grid of power lines. It is often intended to refer specifically to high-voltage (69,000 volts or higher) electricity of the type bought and sold on the wholesale market. An additional stage of service, referred to as distribution, is required to actually deliver usable low-voltage energy to an end-use customer.
Usage Charge	A charge levied on power suppliers or their customers for the use of transmission or distribution lines and facilities.
Utility-Scale	A resource that is sized to provide power to a utility and not directly to an on-site customer.
Variable (Intermittent) Resource (Energy)	Generating resources that have some degree of variability in the production pattern, typically due to weather conditions. An example would be wind energy. The power output from the wind project is entirely dependent upon the wind conditions and will fluctuate with changes in wind conditions.
Visibility	The ability to see and coordinate relevant resource, demand and power-flow attributes in operations and planning horizons.
Volatile Organic Compounds (VOC)	Types of organic compounds which have significant vapor pressures (evaporate easily, forming a gas) and which can affect the environment and human health.
Volatility	A measure of price fluctuations (for example, of a commodity) over a certain period of time.
Voltage Reduction	Any intentional reduction of system voltage by 3% or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.
Volumetric Risk	The effect on revenue of fluctuations in demand for a product or service.
Water Intensity	The amount of water needed to produce a unit of electricity. In general, this document will give water intensity as acre-feet per megawatt-hour.



Watt-Hour	The total amount of energy used in one hour by a device that requires one watt of power for continuous operation. Electric energy sold to retail customers is commonly measured in kilowatt-hours.
Watt	The electrical unit of real power or rate of doing work; specifically, the rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor.
Western Interconnection	The interconnected electrical systems that EnCompass the region of the Western Electricity Coordinating Council of the North American Electric Reliability Council. The region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California (Mexico), and all or portions of the 14 western states in between.
West Texas Intermediate (WTI)	Also known as Texas Sweet Light, is a type of crude oil used as a benchmark in oil pricing and the underlying commodity of New York Mercantile Exchange's oil futures contracts. This is usually the type referenced in Western news reports about oil prices, alongside North Sea Brent Crude. WTI is a light crude that contains about 0.24% sulfur, rating it a sweet (low-sulfur) crude, sweeter than Brent. Its properties and production site make it ideal for being refined in the United States, mostly in the Midwest and Gulf Coast regions.
Wholesale Customer	Any party who purchases electricity in bulk for resale to end-use customers. Wholesale customers may include marketers, utilities and distribution companies, co-ops, and any other entity engaged in energy resale.
Wholesale Electricity Markets	The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.
Winter Heating Season	The November 1 through March 31 period, during which most natural gas use for space heating takes place.
Zonal Price	A pricing mechanism for a specific zone within a control area.



External Data Resources	
Resource	Webpage
Database of State Incentives for Renewables & Efficiency (DSIRE)	https://www.dsireusa.org/
Emissions & Generation Resource Integrated Database (eGRID)	https://www.epa.gov/egrid/data-explorer
EnCompass Power Planning Software	https://anchor-power.com/
Energy Storage Grand Challenge Cost and Performance Assessment, 2020	https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
Existing Hydropower Assets Plan Dataset, 2020	https://hydrosourc.ornl.gov/datasets
Horizons National Database (NDB) and Scenario Service	https://www.horizons-energy.com/data/
Kentucky Energy Profile, 2019	https://eec.ky.gov/Energy/News-Publications/Pages/Kentucky-Energy-Profile.aspx
Kentucky State Dataset, Woods & Poole Economics	https://www.woodsandpoole.com/our-databases/counties-metro-areas/data-pamphlets-state-region-us-totals/
National Renewable Energy Laboratory (NREL)	https://data.nrel.gov/
	https://www.nrel.gov/geothermal/data-tools.html
	https://www.nrel.gov/gis/biomass.html
National Solar Radiation Database	https://maps.nrel.gov/nsrdb-viewer/
NOAA OneStop	https://data.noaa.gov/onestop/
Open Access Technology International, Inc. (OATI webSmartOASIS)	https://www.oasis.oati.com/
Seasonally Adjusted Unemployment Rate Database	https://www.bls.gov/data/tools.htm
S&P Global Market Intelligence	https://www.spglobal.com/
U.S. Energy Information Administration (EIA)	https://www.eia.gov/
	https://www.eia.gov/outlooks/aeo/
	https://www.eia.gov/outlooks/steo/
WINDExchange	https://windexchange.energy.gov/maps-data
2019 State of the Market Report for the MISO Electricity Markets	https://www.potomaceconomics.com/

